STRATHCONA RESOURCES LTD

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2023 AND 2022

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 November 13, 2023 and should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements (and related notes) as at and for the three and nine months ended September 30, 2023 and September 30, 2022 (the "**interim financial statements**") and the Company's audited consolidated financial statements (and related notes) for the year ended December 31, 2022 (the "**annual financial statements**"). The interim financial statements and annual financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"). The interim financial statements and annual financial statements and this MD&A of Strathcona have been prepared by management and were approved by the Company's Board of Directors.

This MD&A contains forward looking information; see "Risk Factors" in this MD&A and "Forward-Looking Information" at the end of this MD&A for further information. The following MD&A also contains financial measures that do not have a standardized meaning under IFRS; 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 references to "Strathcona" or "the Company" before October 3, 2023 are to Strathcona Resources Ltd., a predecessor to AmalCo, and all references on or after October 3, 2023 are to AmalCo. 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 unless otherwise indicated. 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 Calgary-based oil and natural gas company engaged in the acquisition, exploration, development and production of petroleum and natural gas reserves in western Canada. At September 30, 2023, the Company was privately owned by the limited partnerships forming Waterous Energy Fund and its affiliates (collectively, "**WEF**"), and management and employees of the Company.

Strathcona has grown its business through a series of strategic acquisitions. The significant differences in financial and operational results of the Company for the three and nine months ended September 30, 2023 compared to prior periods presented within this MD&A are primarily the result of the transactions discussed below.

On March 11, 2022, Strathcona acquired the remaining 43% interest in both Caltex Resources Ltd. ("**Caltex**") and Stickney Resources Ltd. ("**Stickney**") (together, referred to as the "**Caltex and Stickney Amalgamation**"). The properties acquired were heavy oil properties now included in the Lloydminster Heavy Oil segment and the Tucker thermal oil property now included in the Cold Lake Thermal segment.

On August 29, 2022, Strathcona acquired Serafina Energy Ltd. ("**Serafina**") (transaction referred to as the "**Serafina Acquisition**"). The properties acquired were thermal heavy oil properties now included in the Lloydminster Heavy Oil segment.

Refer to Note 4 of the annual financial statements for further details on these transactions.

RECENT DEVELOPMENTS

On October 3, 2023, Strathcona acquired all of the issued and outstanding common shares of Pipestone Energy Corp. ("**Pipestone**") by way of a plan of arrangement (the "**Arrangement**") under the Business Corporations Act (Alberta) (the "**ABCA**"). As part of the Arrangement, Pipestone and Strathcona amalgamated under the ABCA and continued as "Strathcona Resources Ltd." ("**AmalCo**"). Pipestone shareholders received 0.067967 common shares of AmalCo for each Pipestone common share held and Strathcona shareholders received 0.089278 common shares of AmalCo for each Strathcona Class A common share and Class B common share held (together the "**Pipestone Acquisition**"). As of the date hereof, Strathcona's common shares are listed on the Toronto Stock Exchange (the "**TSX**") under the ticker symbol "SCR". The address and principal place of business of AmalCo is Suite 1900, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

Concurrent with completion of the Arrangement, the Company's Revolving Credit Facility was increased to $2.3 billion, and was drawn upon, in part, to repay indebtedness of Pipestone in the amount of approximately $179.0 million. In connection with the Arrangement, certain amendments were made to both the Revolving Credit Facility and Term Credit Facility (see Note 4 of the interim financial statements and the "Bank Credit Facilities" section of this MD&A).

As at the date hereof, initial accounting for the Arrangement is incomplete, and as such, the value of the assets acquired and the liabilities assumed have not been disclosed.

2023 & 2024 GUIDANCE

The following table details production and capital guidance for the full year 2023 and 2024.

	2023 Guidance	**2024 Guidance**
Production (boe/d)	**155,000**	**190,000 - 195,000**
Capital expenditures ($ billions)	**1.0**	**1.3**

PRODUCTION VOLUMES

	Three Months Ended			**Nine Months Ended**	
	September 30, 2023	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Bitumen (bbl/d)	**58,179**	50,951	53,825	**54,393**	45,460
Heavy oil (bbl/d)	**51,256**	37,693	53,470	**54,034**	25,906
Condensate and light oil (bbl/d)	**10,092**	7,884	10,600	**9,594**	8,261
Total oil production (bbl/d)	**119,527**	96,528	117,895	**118,021**	79,627
Other NGLs (bbl/d)	**7,873**	6,386	7,780	**8,049**	7,055
Natural gas (mcf/d)	**120,366**	101,491	108,612	**114,450**	107,757
Total (boe/d)	**147,461**	119,829	143,778	**145,145**	104,642
% oil and condensate	**81 %**	81 %	82 %	**81 %**	76 %
% liquids	**86 %**	86 %	87 %	**87 %**	83 %

Production volumes increased by 27,632 boe per day for the three months ended September 30, 2023 to an average of 147,461 boe per day compared to 119,829 boe per day for the same quarter of 2022. The increase is primarily attributable to production from properties added through the Serafina Acquisition, which was completed in the third quarter of 2022. The Serafina Acquisition contributed heavy oil production of approximately 26,500 boe per day in the three months ended September 30, 2023 compared to 13,100 boe per day in the same period of 2022. The remaining production increase is attributable to strong well results from the 2022 and 2023 capital programs.

Production volumes increased by 40,503 boe per day for the nine months ended September 30, 2023 to an average of 145,145 boe per day compared to 104,642 boe per day for the same period of 2022. The increase is primarily attributable to incremental production of 6,000 boe per day from properties acquired through the Caltex and Stickney Amalgamation and 25,000 boe per day from properties acquired through the Serafina Acquisition. The remaining production increase is attributable to strong well results from the 2022 and 2023 capital programs.

Production volumes increased approximately 3% during the three months ended September 30, 2023 compared to the three months ended June 30, 2023 as production downtime as a result of facility turnarounds at the Lloydminster Heavy Oil assets were more than offset by new well and base production performance at Cold Lake Thermal properties.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	September 30, 2023	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI[1]	**82.26**	91.55	73.78	**77.39**	98.09
WCS Hardisty[2]	**69.38**	71.69	58.64	**59.76**	82.35
WCS USGC[3]	**77.89**	82.91	66.98	**69.12**	91.85
WTI-WCS Hardisty differential	**(12.88)**	(19.86)	(15.14)	**(17.63)**	(15.73)
WTI-WCS USGC differential	**(4.37)**	(8.64)	(6.79)	**(8.27)**	(6.24)
NYMEX-AECO differential (US$/MMbtu)[4]	**(0.95)**	(4.20)	(0.53)	**(0.67)**	(2.88)
Condensate differential[5]	**(4.26)**	(4.29)	(1.44)	**(0.67)**	(0.85)
Average FX rate (C$/US$)	**1.3410**	1.3059	1.3430	**1.3453**	1.2829
CAD$/bbl unless otherwise indicated					
WTI[1]	**110.38**	119.46	99.11	**104.13**	125.77
WCS Hardisty[2]	**93.04**	93.52	78.76	**80.40**	105.54
WCS USGC[3]	**104.45**	108.16	89.97	**92.99**	117.74
AECO 5A (C$/mcf)[6]	**2.60**	4.16	2.45	**2.76**	5.38
Condensate par at Edmonton	**104.60**	113.89	97.19	**103.21**	124.63
AESO weighted average pool price (C$/MWh)[7]	**155.44**	230.30	164.31	**154.25**	148.57
CDOR (%)[8]	**5.33**	3.14	5.02	**5.08**	1.79

(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 Dollar Offered Rate ("CDOR") percentage for 1 month tenors.

WTI crude oil prices increased 11% in the third quarter of 2023 compared to the second quarter of 2023 and decreased by 10% compared to the third quarter of 2022. Sustained global supply curtailments from OPEC+, notably Saudi Arabia and Russia, combined with growing global demand have continued to strengthen WTI crude oil prices. Pricing was also supported by the narrowing of Canadian heavy oil differentials, at both Hardisty and the U.S. Gulf Coast due to factors such as improved capacity on export pipelines and competing demand from Asia and the U.S. Gulf Coast.

AECO 5A natural gas prices increased 6% in the third quarter of 2023 compared to the prior quarter as AECO production reached new all-time highs in the third quarter while subdued downstream demand allowed storage to fill ahead of winter providing a stable price environment through the second and third quarter of 2023.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales - Net of Blending

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2023	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Bitumen blend	**670.8**	601.2	548.0	**1,689.0**	1,867.7
Heavy oil, blended and raw	**489.5**	369.5	434.6	**1,371.8**	862.2
Condensate and light oil	**94.4**	78.2	90.8	**258.7**	252.0
Other natural gas liquids	**16.0**	20.7	14.5	**52.5**	72.2
Natural gas	**29.5**	43.0	24.9	**88.7**	164.4
Oil and natural gas sales	**1,300.2**	1,112.6	1,112.8	**3,460.7**	3,218.5
Gain (loss) purchased product	**0.4**	—	(0.6)	**(1.2)**	(0.7)
Bitumen - blending cost	**(201.8)**	(206.6)	(209.0)	**(646.8)**	(648.7)
Heavy oil - blending cost	**(36.7)**	(31.9)	(40.8)	**(126.7)**	(123.1)
Oil and natural gas sales - net of blending[1]	**1,062.1**	874.1	862.4	**2,686.0**	2,446.0

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

Oil and natural gas sales, net of blending, increased 22% for the three months ended September 30, 2023 to $1,062.1 million compared to $874.1 million for the same quarter in 2022. This increase is primarily attributable to increased sales volumes substantially from the properties acquired in the Serafina Acquisition, and higher realized prices on bitumen and heavy oil, blended and raw due to lower condensate benchmark pricing.

Oil and natural gas sales, net of blending, increased 10% for the nine months ended September 30, 2023 to $2,686.0 million from $2,446.0 million for the same period in 2022. This increase is primarily attributed to higher sales volumes as a result of properties added through the Caltex and Stickney Amalgamation and the Serafina Acquisition, offset by lower average benchmark commodity prices.

Oil and natural gas sales, net of blending, increased 23% for the three months ended September 30, 2023 to $1,062.1 million compared to $862.4 million for the three months ended June 30, 2023. This increase is primarily due to higher realized prices attributed to higher average benchmark commodity prices, bolstered by stronger sales volumes.

Average Realized Prices

	Three Months Ended			Nine Months Ended	
	September 30, 2023	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Bitumen blend ($/bbl)[1][2]	**88.06**	86.15	69.12	**70.19**	99.60
Heavy oil, blended and raw ($/bbl)[1][2]	**92.53**	92.69	81.86	**82.49**	100.88
Condensate and light oil ($/bbl)	**101.67**	107.81	94.13	**98.77**	111.74
Realized oil ($/bbl)	**91.16**	90.57	77.12	**78.19**	101.28
Other natural gas liquids ($/bbl)	**22.09**	35.23	20.48	**23.90**	37.49
Natural gas ($/mcf)	**2.66**	4.61	2.52	**2.84**	5.59
Combined ($/boe)	**77.55**	79.18	66.16	**67.24**	86.09

(1) Realized prices are calculated using oil and natural gas sales, net of blending.
(2) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see “Specified Financial Measures” section of this MD&A.

Combined realized price decreased 2% for the three months ended September 30, 2023 to $77.55 per boe compared to $79.18 per boe in the same quarter of 2022. The decrease is primarily due to lower average benchmark WTI and AECO prices, offset by narrowed WCS differentials at both Hardisty and the US Gulf Coast.

Combined realized price decreased 22% for the nine months ended September 30, 2023 to $67.24 per boe compared to $86.09 per boe in the same period of 2022. The decrease is primarily attributable to reductions in benchmark commodity prices.

Combined realized price increased 17% for the three months ended September 30, 2023 to $77.55 per boe compared to $66.16 per boe for the three months ended June 30, 2023. The increase is primarily due to higher average benchmark commodity prices.

ROYALTIES

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Crown royalties	**142.8**	122.0	70.5	**308.8**	341.5
Freehold royalties	**16.7**	10.9	15.2	**42.7**	25.9
Gross overriding royalties	**38.1**	34.2	12.5	**56.7**	157.6
Other royalties	**5.1**	3.5	8.0	**13.8**	6.8
Royalties	**202.7**	170.6	106.2	**422.0**	531.8
Effective royalty rate (%)(1)	**19.1 %**	19.5 %	12.3 %	**15.7 %**	21.7 %

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

For the three and nine months ended September 30, 2023, the average effective royalty rate was 19.1% and 15.7%, respectively, compared to 19.5% and 21.7% for the same periods in 2022. These decreases are primarily the result of lower benchmark commodity prices.

For the three months ended September 30, 2023, the average effective royalty rate increased to 19.1% from 12.3% in the second quarter of 2023. This increase is primarily driven by higher average benchmark commodity prices during the third quarter of 2023 as well as favorable gas cost allowance credits and adjustments received on annual government filings relating to production within enhanced oil recovery and oil sands projects.

PRODUCTION AND OPERATING EXPENSES

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Production and operating - Energy	**81.4**	77.4	79.7	**249.8**	213.1
Production and operating - Non-energy	**113.9**	75.9	110.9	**340.7**	212.4
Production and operating expenses	**195.3**	153.3	190.6	**590.5**	425.5
Production and operating - Energy ($/boe)	**5.94**	7.01	6.11	**6.25**	7.46
Production and operating - Non-energy ($/boe)	**8.32**	6.88	8.51	**8.53**	7.44
Production and operating expenses ($/boe)	**14.26**	13.89	14.62	**14.78**	14.90

Production and operating expenses increased to $195.3 million ($14.26 per boe) and $590.5 million ($14.78 per boe) for the three and nine months ended September 30, 2023, respectively, from $153.3 million ($13.89 per boe) and $425.5 million ($14.90 per boe) in the same periods in 2022. These increases are primarily attributable to: increased production volumes as a result of the Caltex and Stickney Amalgamation and the Serafina Acquisition which added $30.7 million and $142.3 million in incremental costs in the three and nine month periods, respectively; and general cost inflation across all segments; offset by lower energy costs at Cold Lake Thermal as a result of lower natural gas prices.

Production and operating expenses increased modestly during the three months ended September 30, 2023 compared to the three months ended June 30, 2023.

TRANSPORTATION AND PROCESSING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended **September 30, 2023**	 September 30, 2022	 June 30, 2023	Nine Months Ended **September 30, 2023**	 September 30, 2022
Transportation expenses	**107.6**	57.3	97.9	**326.2**	123.7
Processing expenses	**6.9**	6.3	6.9	**21.0**	19.4
Transportation and processing expenses	**114.5**	63.6	104.8	**347.2**	143.1
$ per boe	**8.36**	5.76	8.04	**8.69**	5.01

Transportation and processing expenses increased to $114.5 million ($8.36 per boe) and $347.2 million ($8.69 per boe) for the three and nine months ended September 30, 2023, respectively, from $63.6 million ($5.76 per boe) and $143.1 million ($5.01 per boe) in the same periods of 2022. These increases are primarily attributable to the Caltex and Stickney Amalgamation and the Serafina Acquisition which resulted in increased production volumes. This incremental production is transported by truck and rail which has a higher transportation cost per barrel compared to legacy Strathcona heavy oil assets which are primarily transported by pipeline.

Transportation and processing expenses increased by 9% for the three months ended September 30, 2023 to $114.5 million ($8.36 per boe) from $104.8 million ($8.04 per boe) in the second quarter of 2023 as a result of increased tariffs and fees on certain take-or-pay arrangements.

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

($ millions, unless otherwise indicated)	Three Months Ended **September 30, 2023**	 September 30, 2022	 June 30, 2023	Nine Months Ended September 30, 2023	 September 30, 2022
Depletion expense[(1)]	**163.6**	94.5	164.1	**484.8**	242.9
Depreciation and amortization expense	**8.0**	2.0	6.6	**20.6**	8.4
DD&A	**171.6**	96.5	170.7	**505.4**	251.3
$ per boe	**12.53**	8.74	13.10	**12.65**	8.80

(1) Effective December 31, 2022, Strathcona voluntarily changed its accounting policy with respect to its decommissioning provision to utilize a credit-adjusted discount rate, which was applied retrospectively. As a result, certain comparative figures have been restated. Refer to "Changes in Accounting Policies" section of this MD&A.

DD&A expense increased 78% for the three months ended September 30, 2023 to $171.6 million ($12.53 per boe) compared to $96.5 million ($8.74 per boe) for the same quarter of 2022. For the nine months ended September 30, 2023, DD&A expense increased 101% to $505.4 million ($12.65 per boe) from $251.3 million ($8.80 per boe) for the same period of 2022. These increases are primarily due to higher sales volumes as a result of the Caltex and Stickney Amalgamation and the Serafina Acquisition and an increased weighting to properties with higher depletion rates.

GENERAL AND ADMINISTRATION EXPENSES ("G&A")

($ millions, unless otherwise indicated)	Three Months Ended **September 30, 2023**	 September 30, 2022	 June 30, 2023	Nine Months Ended **September 30, 2023**	 September 30, 2022
G&A expenses	**20.7**	16.2	20.8	**67.4**	44.6
$ per boe	**1.51**	1.47	1.59	**1.69**	1.56

For the three and nine months ended September 30, 2023, G&A expenses increased to $20.7 million ($1.51 per boe) and $67.4 million ($1.69 per boe), respectively, from $16.2 million ($1.47 per boe) and $44.6 million ($1.56 per boe) in the same periods in 2022. The increases are primarily due to higher staffing levels, consultant fees and information technology costs incurred following the Caltex and Stickney Amalgamation and the Serafina Acquisition.

G&A expenses remained consistent during the three months ended September 30, 2023 compared to the three months ended June 30, 2023.

INTEREST

($ millions, unless otherwise indicated)	Three Months Ended **September 30, 2023**	 September 30, 2022	 June 30, 2023	Nine Months Ended **September 30, 2023**	 September 30, 2022
Interest expense	**50.2**	28.3	50.3	**154.6**	59.5
Weighted average interest rate (%)	**6.3 %**	5.7 %	6.4 %	**6.5 %**	5.0 %

Interest expense increased 77% for the three months ended September 30, 2023 to $50.2 million compared to $28.3 million for the same quarter of 2022. This increase is primarily the result of incremental borrowings drawn in conjunction with the Serafina Acquisition as well as higher interest rates.

For the nine months ended September 30, 2023, interest expense increased 160% to $154.6 million from $59.5 million for the same period of 2022. This increase is primarily the result of incremental borrowings drawn in conjunction with the Caltex and Stickney Amalgamation and the Serafina Acquisition as well as higher interest rates

The impact of higher interest rates in the first nine months of 2023 were partially mitigated through interest rate swaps entered into during the second quarter of 2023. See the "*Risk Management - Market Risk - Interest Rate Risk*" section of this MD&A.

During the nine months ended September 30, 2023, the Company recorded $34.7 million in interest expense on the Senior Notes (as defined below) (September 30, 2022 – $33.1 million); and $131.1 million in interest expense on the Credit Facilities (as defined below) (September 30, 2022 - $26.4 million); and a realized gain of $11.2 million on interest rate swaps (September 30, 2022 - $nil).

Interest expense remained consistent during the three months ended September 30, 2023 compared to the three months ended June 30, 2023.

FINANCE COSTS

($ millions, unless otherwise indicated)	Three Months Ended **September 30, 2023**	 September 30, 2022	 June 30, 2023	Nine Months Ended September 30, 2023	 September 30, 2022
Accretion of lease obligations	**3.0**	2.9	2.8	**8.6**	8.7
Accretion of decommissioning provision (1)	**7.1**	2.8	7.3	**21.6**	6.8
Amortization of debt issuance costs	**3.2**	2.6	3.1	**9.5**	5.6
Accretion of other obligations	**4.8**	—	4.6	**14.0**	—
Finance costs	**18.1**	8.3	17.8	**53.7**	21.1

(1) Effective December 31, 2022, Strathcona voluntarily changed its accounting policy with respect to its decommissioning provision to utilize a credit-adjusted discount rate, which was applied retrospectively. As a result, certain comparative figures have been restated. Refer to "Changes in Accounting Policies" section of this MD&A.

For the three months ended September 30, 2023, finance costs increased 118% to $18.1 million compared to $8.3 million in the same quarter of 2022. For the nine months ended September 30, 2023, finance costs increased 155% to $53.7 million from $21.1 million in the same period of 2022. These increases are due to higher accretion as a result of decommissioning liabilities assumed through the Caltex and Stickney Amalgamation and the Serafina Acquisition; higher amortization of debt issuance costs as a result of fees incurred on the Credit Facilities; and accretion of other obligations which is related to the asset-backed financing agreement entered into in late December 2022 (see Note 5 of the interim financial statements).

INCOME TAX AND TAX POOLS

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Current tax (recovery)	**—**	—	—	**(46.9)**	—
Deferred tax expense (recovery)	**44.6**	(191.0)	81.1	**206.2**	(414.1)
Income tax expense (recovery)	**44.6**	(191.0)	81.1	**159.3**	(414.1)

During the nine months ended September 30, 2023, a current tax recovery of $46.9 million was recorded upon filing of the final tax return of Serafina, 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.

During the nine months ended September 30, 2022, a deferred tax recovery of $414.1 million was recorded. Deferred tax recoveries were recorded to offset deferred tax liabilities on the Caltex Amalgamation and the Serafina Acquisition. The Company determined that its deductible temporary differences met the threshold for utilization after the Serafina Acquisition on August 29, 2022.

Tax Pools

As at September 30, 2023, the Company had approximately $5,609.1 million (December 31, 2022 - $6,038.1 million) of tax pools available for deduction in future periods as shown in the table below.

($ millions, unless otherwise indicated)	Annual Pool Deduction Rate	**September 30, 2023**	December 31, 2022
Canadian oil and gas property expenditures	10 %	**887.8**	955.4
Canadian development expenditures(1)	30 %	**801.3**	731.0
Canadian exploration expenditures(1)	100 %	**4.1**	8.8
Undepreciated capital costs(2)	4 % - 55 %	**1,207.4**	1,178.9
Non-capital losses	100 %	**2,268.2**	2,711.7
Other(3)		**440.3**	452.3
Total tax pools		**5,609.1**	6,038.1

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

(2) As at September 30, 2023, approximately 96% (December 31, 2022 – 97%) of costs in this pool have an annual deduction rate of 25%.

(3) Other tax deductions include scientific research and experimental development costs and credits and financing costs. As at September 30, 2023, approximately 89% (December 31, 2022 – 86%) of these deductions have an annual deduction rate of 100%.

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. There have been no significant changes in the Company's risk management policies or exposures during the three and nine months ended September 30, 2023.

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, 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.

Subsequent to September 30, 2023, the Company amended certain WCS commodity contracts for proceeds of US$14.3 million.

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
Dec 1, 2023 - Dec 31, 2023	Swap	WTI	USD	77,000	bbl/d	$77.77
Jan 1, 2024 - Jan 31, 2024	Swap	WTI	USD	80,000	bbl/d	$76.77
Dec 1, 2023 - Dec 31, 2023	Sold Put	WTI	USD	77,000	bbl/d	$60.00
Jan 1, 2024 - Jan 31, 2024	Sold Put	WTI	USD	80,000	bbl/d	$60.00
Mar 1, 2024 - May 31, 2024	Swap	WTI	USD	5,000	bbl/d	$48.10
Dec 1, 2023 - Jan 31, 2024	Collar	WTI	USD	10,000	bbl/d	$60.00/$118.95
Feb 1, 2024 - Feb 29, 2024	Collar	WTI	USD	80,000	bbl/d	$60.00/$93.00
Mar 1, 2024 - Mar 31, 2024	Collar	WTI	USD	75,000	bbl/d	$60.00/$105.29
Mar 1, 2024 - Aug 31, 2024	Bought Call(2)	WTI	USD	15,739	bbl/d	$165.00
Nov 1, 2023 - Nov 30, 2023	Swap	WTI	CAD	2,750	bbl/d	$108.85
Dec 1, 2023 - Dec 31, 2023	Swap	WTI	CAD	2,500	bbl/d	$109.24
Jan 1, 2024 - Mar 31, 2024	Swap	WTI	CAD	2,000	bbl/d	$111.45
Apr 1, 2024 - Jun 30, 2024	Swap	WTI	CAD	1,750	bbl/d	$109.89
Nov 1, 2023 - Nov 30, 2023	Swap	WCS	USD	3,000	bbl/d	$(15.45)
May 1, 2024 - Dec 31, 2024	Swap	WCS	USD	10,000	bbl/d	$(14.25)
Nov 1, 2023 - Apr 30, 2024	Collar	AECO	CAD	120,000	GJ/d	$2.00/$3.63

(1) For swap contracts, Strathcona receives the fixed price and pays the index. Call options are in-the-money if the index price is above the strike price. For sold calls, Strathcona receives the strike price, and for bought calls, Strathcona pays the strike price. Put options are in-the-money if the index price is below the strike price. For sold puts, Strathcona pays the strike price. 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.

(2) This contract has a premium of US$13.35/bbl payable over the term of the contract.

(3) The Company has a premium of US$14.45/bbl on expired contracts of 14,400 bbl/d which is payable from March 1, 2024 to August 31, 2024.

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 contracts on oil and natural gas sales, as at the date of this MD&A.

Term	Contract	USD per Month	CAD/USD Floor	CAD/USD Ceiling
Mar 1, 2024 - Feb 28, 2025	Collar	30.5 million	1.2081	1.2410

Interest Rate Risk

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

The following table summarizes the Company's interest rate swaps as at the date of this MD&A.

Notional (C$)	Term	Contract	Index	Contract Price
1,500.0 million	May 1, 2023 - Apr 30, 2028	Swap	1 month CDOR	3.4316%

For a listing of the Company's commodity contracts, foreign exchange and interest rate contracts outstanding as at September 30, 2023 refer to Note 13 in the interim 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			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Realized (gain) loss on risk management contracts(1)	**56.1**	68.1	0.4	**61.9**	262.8
Unrealized loss (gain) on risk management contracts(2)	**209.7**	(251.4)	(142.5)	**(2.4)**	(151.7)
Total loss (gain) on risk management contracts	**265.8**	(183.3)	(142.1)	**59.5**	111.1
Realized (gain) loss on risk management contract per boe	**4.09**	6.18	0.03	**1.55**	9.20

(1) Includes realized (gains) losses on commodity price contracts and foreign exchange contracts.

(2) Includes the movement in the valuation of commodity price contracts, foreign exchange contracts and interest rate swaps.

Strathcona realized a loss on risk management contracts of $56.1 million and $61.9 million, for the three and nine months ended September 30, 2023, respectively, compared to a loss of $68.1 million and $262.8 million for the same periods in 2022 and a loss of $0.4 million for the three months ended June 30, 2023. The realized loss on risk management contracts were predominantly due to higher realized commodity benchmark prices in comparison to contracted hedge pricing. The impact of cash settlements on foreign exchange contracts was nominal for the periods presented.

As at September 30, 2023, the mark-to-market value of risk management contracts was a net liability of $210.2 million (December 31, 2022 - net liability of $212.6 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 13 to the interim financial statements.

TRANSACTION RELATED COSTS

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Transaction related costs	**3.5**	2.3	0.4	**5.1**	5.2

Transaction related costs primarily pertain to the legal and consulting costs associated with corporate transactions, as well as consulting fees for ongoing integration work. The transaction costs incurred for the three months ended September 30, 2023 primarily relate to the Pipestone Acquisition. Refer to the "Recent Developments" section of this MD&A for further information.

CAPITAL EXPENDITURES

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

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Cold Lake Thermal	**78.0**	64.8	79.3	**236.3**	168.1
Lloydminster Heavy Oil	**99.2**	38.8	80.1	**264.3**	74.5
Montney	**80.7**	53.1	69.6	**211.7**	146.8
Corporate	**2.3**	0.8	2.7	**8.3**	3.0
Capital expenditures	**260.2**	157.5	231.7	**720.6**	392.4

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

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
Drilling, completion and equipping	**152.9**	98.1	128.3	**415.2**	243.3
Facilities and pipelines	**78.3**	34.0	68.3	**214.5**	102.4
Recompletion, workovers and polymer powder	**17.6**	21.0	18.5	**50.9**	31.6
Capitalized G&A and other expenditures	**11.4**	4.4	16.6	**40.0**	15.1
Capital expenditures	**260.2**	157.5	231.7	**720.6**	392.4

Capital expenditures increased 65% for the three months ended September 30, 2023 to $260.2 million compared to $157.5 million for the same quarter of 2022. This increase is primarily the result of $53.7 million of capital spending on the assets acquired through the Serafina Acquisition and increased drilling and completion activity at the Company's Montney and Cold Lake segments.

For the three months ended September 30, 2023, drilling, completion and equipping activities accounted for 59% of capital expenditures as the Company drilled 59 new wells during the quarter; 20 in Cold Lake Thermal, 31 in Lloydminster Heavy Oil, and 8 in Montney. Drilling, completion and equipping activities for the nine months ended September 30, 2023 accounted for 58% of capital expenditures as the Company drilled 175 new wells; 43 in Cold Lake Thermal, 118 in Lloydminster Heavy Oil and 14 in Montney.

Capital expenditures increased 84% for the nine months September 30, 2023 to $720.6 million compared to $392.4 million for the same quarter of 2022. This increase is the result of additional $278.2 million of capital spending made on the assets acquired through the Caltex and Stickney Amalgamation and the Serafina Acquisition and increased drilling and completion activity at the Company's Montney and Cold Lake segments.

FOREIGN EXCHANGE

($ millions, unless otherwise indicated)	Three Months Ended **September 30, 2023**	September 30, 2022	June 30, 2023	Nine Months Ended **September 30, 2023**	September 30, 2022
Realized (gain) loss	**(1.8)**	(3.1)	0.3	**(1.3)**	(2.8)
Unrealized (gain) loss - Senior Notes	**16.8**	47.8	(13.7)	**1.2**	59.6
Unrealized (gain) loss - Credit Facility	**33.9**	143.0	(17.4)	**(9.2)**	144.9
Unrealized (gain) loss - cross-currency swaps	**(33.3)**	(140.0)	18.2	**7.2**	(141.3)
Unrealized (gain) loss gain - other	**1.3**	2.3	0.4	**0.9**	1.4
Foreign Exchange (gain) loss	**16.9**	50.0	(12.2)	**(1.2)**	61.8

Foreign exchange for the three and nine months ended September 30, 2023 resulted in a loss of $16.9 million and a gain of $1.2 million, respectively, compared to losses of $50.0 million and $61.8 million in the same periods of 2022 and a gain of $12.2 million for the three months ended June 30, 2023. The foreign exchange loss was driven by the weakening of the CAD/USD exchange rate resulting in an unrealized loss on U.S. dollar denominated debt balances net of cross-currency swaps.

SEGMENT RESULTS

Strathcona has three operating segments:

- Cold Lake Thermal which includes three producing assets in the Cold Lake region of Northern Alberta: Lindbergh, Orion and Tucker;
- Lloydminster Heavy Oil which has multiple large oil-in-place reservoirs accessed through enhanced oil recovery techniques, primarily located in Southwest Saskatchewan; and
- Montney which includes assets in the Northwest Alberta Kakwa region and the Northeast British Columbia Groundbirch region.

All amounts not attributable to an operating segment are captured in "Corporate and Eliminations".

For the Three Months Ended	Cold Lake Thermal Segment			Lloydminster Heavy Oil Segment			Montney Segment			Corporate and Eliminations			Consolidated		
	Sept 30, 2023	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023
Production and sales volumes															
Production volumes (boe/d)	**58,179**	50,951	53,829	**51,482**	38,260	53,687	**37,800**	30,618	36,262	**—**	—	—	**147,461**	119,829	143,778
Sales volumes (boe/d)	**57,888**	49,787	53,892	**53,189**	39,587	53,083	**37,797**	30,618	36,264	**—**	—	—	**148,874**	119,992	143,239
Segment revenues															
Oil and natural gas sales	**671.1**	600.0	547.6	**490.2**	372.0	435.2	**139.3**	140.6	129.4	**(0.4)**	—	0.6	**1,300.2**	1,112.6	1,112.8
Sales of purchased products	**—**	—	—	**—**	—	—	**—**	—	—	**7.2**	3.9	14.0	**7.2**	3.9	14.0
Blending costs	**(201.7)**	(206.6)	(208.3)	**(36.8)**	(31.9)	(41.5)	**—**	—	—	**—**	—	—	**(238.5)**	(238.5)	(249.8)
Purchased product	**—**	—	—	**—**	—	—	**—**	—	—	**(6.8)**	(3.9)	(14.6)	**(6.8)**	(3.9)	(14.6)
Oil and natural gas sales, net of blending[1]	**469.4**	393.4	339.3	**453.4**	340.1	393.7	**139.3**	140.6	129.4	**—**	—	—	**1,062.1**	874.1	862.4
Segment expenses															
Royalties	**134.1**	99.5	66.5	**55.1**	47.1	35.4	**13.5**	24.0	4.3	**—**	—	—	**202.7**	170.6	106.2
Production and operating - Energy	**53.9**	56.5	49.7	**27.4**	20.3	29.1	**0.1**	0.6	0.9	**—**	—	—	**81.4**	77.4	79.7
Production and operating - Non-energy	**41.0**	34.7	43.7	**57.6**	28.5	50.8	**15.3**	12.7	16.4	**—**	—	—	**113.9**	75.9	110.9
Transportation and processing	**24.0**	17.9	18.7	**71.9**	28.8	66.7	**18.6**	16.9	19.4	**—**	—	—	**114.5**	63.6	104.8
Acquired inventory	**—**	—	—	**—**	54.2	—	**—**	—	—	**—**	—	—	**—**	54.2	—
Field Operating Income[1]	**216.4**	184.8	160.7	**241.4**	161.2	211.7	**91.8**	86.4	88.4	**—**	—	—	**549.6**	432.4	460.8
Depletion, depreciation and amortization	**39.2**	37.0	36.9	**104.8**	41.2	107.6	**23.8**	16.3	22.7	**3.8**	2.0	3.5	**171.6**	96.5	170.7
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**20.7**	16.2	20.8	**20.7**	16.2	20.8
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(0.9)**	(1.2)	(0.2)	**(0.9)**	(1.2)	(0.2)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**50.2**	28.3	50.3	**50.2**	28.3	50.3
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**18.1**	8.3	17.8	**18.1**	8.3	17.8
Operating Earnings[1]													**289.9**	284.3	201.4
Loss on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**56.1**	68.1	0.4	**56.1**	68.1	0.4
Loss (gain) on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**209.7**	(251.4)	(142.5)	**209.7**	(251.4)	(142.5)
Foreign exchange (gain) loss - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(1.8)**	(3.1)	0.3	**(1.8)**	(3.1)	0.3
Foreign exchange loss (gain) - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**18.7**	53.1	(12.5)	**18.7**	53.1	(12.5)
Transaction related costs	**—**	—	—	**—**	—	—	**—**	—	—	**3.5**	2.3	0.4	**3.5**	2.3	0.4
Unrealized loss on Sable remediation fund	**—**	—	—	**—**	—	—	**—**	—	—	**0.2**	—	0.1	**0.2**	—	0.1
Deferred tax expense (recovery)	**—**	—	—	**—**	—	—	**—**	—	—	**44.6**	(191.0)	81.1	**44.6**	(191.0)	81.1
(Loss) income and comprehensive (loss) income													**(41.1)**	606.3	274.1

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

For the Three Months Ended ($/boe)	Cold Lake Thermal Segment			Lloydminster Heavy Oil Segment			Montney Segment			Corporate and Eliminations			Consolidated		
	Sept 30, 2023	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023	**Sept 30, 2023**	Sept 30, 2022	June 30, 2023
Segment revenues															
Oil and natural gas sales	**92.81**	93.01	78.97	**94.79**	95.71	84.15	**40.06**	49.91	39.22	**(0.03)**	—	0.05	**81.88**	84.58	72.23
Sales of purchased products	**—**	—	—	**—**	—	—	**—**	—	—	**0.53**	0.35	1.07	**0.53**	0.35	1.07
Blending costs	**(4.67)**	(7.12)	(9.78)	**(2.13)**	(2.33)	(2.65)	**—**	—	—	**—**	—	—	**(4.36)**	(5.40)	(6.02)
Purchased product	**—**	—	—	**—**	—	—	**—**	—	—	**(0.50)**	(0.35)	(1.12)	**(0.50)**	(0.35)	(1.12)
Oil and natural gas sales, net of blending(1)	**88.14**	85.89	69.19	**92.66**	93.38	81.50	**40.06**	49.91	39.22	**—**	—	—	**77.55**	79.18	66.16
Segment expenses															
Royalties	**25.18**	21.72	13.57	**11.26**	12.93	7.33	**3.88**	8.52	1.30	**—**	—	—	**14.80**	15.45	8.15
Production and operating - Energy	**10.12**	12.34	9.86	**5.60**	5.57	6.02	**0.03**	0.21	0.28	**—**	—	—	**5.94**	7.01	6.11
Production and operating - Non-energy	**7.70**	7.58	9.17	**11.77**	7.83	10.52	**4.40**	4.51	4.98	**—**	—	—	**8.32**	6.88	8.51
Transportation and processing	**4.51**	3.91	3.80	**14.69**	7.91	13.82	**5.35**	6.00	5.88	**—**	—	—	**8.36**	5.76	8.04
Acquired inventory	**—**	—	—	**—**	14.88	—	**—**	—	—	**—**	—	—	**—**	4.92	—
Field Operating Netback(1)	**40.63**	40.34	32.79	**49.34**	44.26	43.81	**26.40**	30.67	26.78	**—**	—	—	**40.13**	39.16	35.35
Depletion, depreciation and amortization	**7.36**	8.08	7.53	**21.42**	11.31	22.28	**6.84**	5.79	6.89	**0.28**	0.18	0.27	**12.53**	8.74	13.10
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**1.51**	1.47	1.59	**1.51**	1.47	1.59
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(0.07)**	(0.11)	(0.01)	**(0.07)**	(0.11)	(0.01)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**3.67**	2.56	3.86	**3.67**	2.56	3.86
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**1.32**	0.75	1.36	**1.32**	0.75	1.36
Operating Earnings (1)													**21.17**	25.75	15.45
Effective royalty rate (%)(1)	**28.6**	25.3	19.6	**12.2**	13.8	9.0	**9.7**	17.1	3.3				**19.1**	19.5	12.3

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

For the Nine Months Ended	Cold Lake Thermal Segment		Lloydminster Heavy Oil Segment		Montney Segment		Corporate and Eliminations		Consolidated	
	September 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022	**September 30, 2023**	September 30, 2022	**September 30, 2023**	September 30, 2022	**September 30, 2023**	September 30, 2022
Production and sales volumes										
Production volumes (boe/d)	**54,395**	45,460	**54,247**	26,230	**36,503**	32,952	**—**	—	**145,145**	104,642
Sales volumes (boe/d)	**54,330**	44,833	**55,505**	26,837	**36,503**	32,952	**—**	(839)	**146,338**	103,783
Segment revenues										
Oil and natural gas sales	**1,687.0**	1,866.5	**1,374.8**	866.4	**397.7**	503.9	**1.2**	(18.3)	**3,460.7**	3,218.5
Sales of purchased product	**—**	—	**—**	—	**—**	—	**35.0**	46.5	**35.0**	46.5
Blending costs	**(644.6)**	(655.7)	**(128.9)**	(135.1)	**—**	—	**—**	19.0	**(773.5)**	(771.8)
Purchased product	**—**	—	**—**	—	**—**	—	**(36.2)**	(47.2)	**(36.2)**	(47.2)
Oil and natural gas sales, net of blending(1)	**1,042.4**	1,210.8	**1,245.9**	731.3	**397.7**	503.9	**—**	—	**2,686.0**	2,446.0
Segment expenses										
Royalties	**249.5**	355.2	**133.4**	112.4	**39.1**	64.2	**—**	—	**422.0**	531.8
Production and operating - Energy	**158.8**	173.0	**89.1**	37.5	**1.9**	2.6	**—**	—	**249.8**	213.1
Production and operating - Non-energy	**129.0**	93.6	**165.7**	78.6	**46.0**	40.2	**—**	—	**340.7**	212.4
Transportation and processing	**61.7**	49.6	**228.3**	38.6	**57.2**	54.9	**—**	—	**347.2**	143.1
Acquired inventory	**—**	—	**—**	54.2	**—**	—	**—**	—	**—**	54.2
Field Operating Income(1)	**443.4**	539.4	**629.4**	410.0	**253.5**	342.0	**—**	—	**1,326.3**	1,291.4
Depletion, depreciation and amortization	**106.0**	93.3	**319.7**	98.7	**69.2**	50.9	**10.5**	8.4	**505.4**	251.3
General and administrative	**—**	—	**—**	—	**—**	—	**67.4**	44.6	**67.4**	44.6
Other income	**—**	—	**—**	—	**—**	—	**(1.1)**	(3.8)	**(1.1)**	(3.8)
Interest expense	**—**	—	**—**	—	**—**	—	**154.6**	59.5	**154.6**	59.5
Finance costs	**—**	—	**—**	—	**—**	—	**53.7**	21.1	**53.7**	21.1
Operating Earnings(1)									**546.3**	918.7
Loss on risk management contracts - realized	**—**	—	**—**	—	**—**	—	**61.9**	262.8	**61.9**	262.8
(Gain) on risk management contracts - unrealized	**—**	—	**—**	—	**—**	—	**(2.4)**	(151.7)	**(2.4)**	(151.7)
Foreign exchange (gain) - realized	**—**	—	**—**	—	**—**	—	**(1.3)**	(2.8)	**(1.3)**	(2.8)
Foreign exchange loss - unrealized	**—**	—	**—**	—	**—**	—	**0.1**	64.6	**0.1**	64.6
Transaction related costs	**—**	—	**—**	—	**—**	—	**5.1**	5.2	**5.1**	5.2
Unrealized loss on Sable remediation fund	**—**	—	**—**	—	**—**	—	**0.1**	0.7	**0.1**	0.7
Share of equity investment income	**—**	—	**—**	—	**—**	—	**—**	(11.3)	**—**	(11.3)
Gain on step acquisitions of equity method investee	**—**	—	**—**	—	**—**	—	**—**	(132.1)	**—**	(132.1)
Loss on termination of lease liability	**—**	—	**—**	—	**—**	—	**—**	1.4	**—**	1.4
Current income tax (recovery)	**—**	—	**—**	—	**—**	—	**(46.9)**	—	**(46.9)**	—
Deferred tax expense (recovery)	**—**	—	**—**	—	**—**	—	**206.2**	(414.1)	**206.2**	(414.1)
Income and comprehensive income									**323.5**	1,296.0

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

For the Nine Months Ended ($/boe)	Cold Lake Thermal Segment		Lloydminster Heavy Oil Segment		Montney Segment		Corporate and Eliminations		Consolidated	
	September 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022	**September 30, 2023**	September 30, 2022	**September 30, 2023**	September 30, 2022	**September 30, 2023**	September 30, 2022
Segment revenues										
Oil and natural gas sales	**80.82**	106.57	**85.19**	106.98	**39.91**	56.01	**0.03**	(0.64)	**73.67**	93.53
Sales of purchased products	**—**	—	**—**	—	**—**	—	**0.88**	1.63	**0.88**	1.63
Blending costs	**(10.54)**	(7.64)	**(2.96)**	(7.16)	**—**	—	**—**	0.66	**(6.40)**	(7.42)
Purchased product	**—**	—	**—**	—	**—**	—	**(0.91)**	(1.65)	**(0.91)**	(1.65)
Oil and natural gas sales, net of blending[1]	**70.28**	98.93	**82.23**	99.82	**39.91**	56.01	**—**	—	**67.24**	86.09
Segment expenses										
Royalties	**16.83**	29.02	**8.80**	15.34	**3.93**	7.14	**—**	—	**10.56**	18.62
Production and operating - Energy	**10.70**	14.13	**5.88**	5.12	**0.19**	0.29	**—**	—	**6.25**	7.46
Production and operating - Non-energy	**8.70**	7.65	**10.94**	10.73	**4.61**	4.47	**—**	—	**8.53**	7.44
Transportation and processing	**4.16**	4.05	**15.07**	5.27	**5.74**	6.10	**—**	—	**8.69**	5.01
Acquired inventory	**—**	—	**—**	7.40	**—**	—	**—**	—	**—**	1.90
Field Operating Netback [1]	**29.89**	44.08	**41.54**	55.96	**25.44**	38.01	**—**	—	**33.21**	45.66
Depletion, depreciation and amortization	**7.15**	7.62	**21.10**	13.47	**6.94**	5.66	**0.26**	0.29	**12.65**	8.80
General and administrative	**—**	—	**—**	—	**—**	—	**1.69**	1.56	**1.69**	1.56
Other income	**—**	—	**—**	—	**—**	—	**(0.03)**	(0.13)	**(0.03)**	(0.13)
Interest expense	**—**	—	**—**	—	**—**	—	**3.87**	2.08	**3.87**	2.08
Finance costs	**—**	—	**—**	—	**—**	—	**1.34**	0.74	**1.34**	0.74
Operating Earnings [1]									**13.69**	32.61
Effective royalty rate (%)[1]	**23.9**	29.3	**10.7**	15.4	**9.8**	12.7			**15.7**	21.7

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

Cold Lake Thermal

Production at the Cold Lake Thermal segment, for the three months ended September 30, 2023, increased to 58,179 boe per day from 50,951 boe per day compared to same quarter of 2022. The increase in production is primarily due to production brought on from new drills in the year and improved base production performance at the Company's Lindbergh property.

For the nine months ended September 30, 2023, production increased to 54,395 boe per day from 45,460 boe per day in the same period of 2022. The increase is primarily due to new wells drilled as well as the addition of production from the Tucker property, acquired through the Stickney Amalgamation, which contributed approximately 18,000 bbl/d in 2023 compared to 14,700 bbl/d in the same period of 2022.

Oil and natural gas sales net of blending increased to $469.4 million ($88.14 per boe) during the three months ended September 30, 2023 compared to $393.4 million ($85.89 per boe) for the same quarter of 2022. The increase is primarily due to higher sales volumes and lower blending cost as a result of decreased benchmark condensate pricing.

Oil and natural gas sales net of blending decreased to $1,042.4 million ($70.28 per boe) during the nine months ended September 30, 2023 compared to $1,210.8 million ($98.93 per boe) in the same period of 2022. The decrease is primarily due to reductions in benchmark commodity prices, offset by higher sales volumes.

The effective royalty rate for the three months ended September 30, 2023 increased to 28.6% from 25.3% in the same quarter of 2022. The effective royalty rate for the nine months ended September 30, 2023 decreased to 23.9% from 29.3% in the same period of 2022 due to lower benchmark pricing. These changes are reflective of the movement in benchmark pricing in the respective periods.

Energy related production and operating costs for the three and nine months ended September 30, 2023 decreased to $53.9 million ($10.12 per boe) and $158.8 million ($10.70 per boe), respectively, from $56.5 million ($12.34 per boe) and $173.0 million ($14.13 per boe) in the same periods of 2022. These decreases are primarily attributable to the lower price of natural gas in 2023 offset, for the nine months ended September 30, 2023, by higher volumes from the Stickney Amalgamation.

For the three and nine months ended September 30, 2023 non-energy related production and operating costs increased to $41.0 million ($7.70 per boe) and $129.0 million ($8.70 per boe), respectively, from $34.7 million ($7.58 per boe) and $93.6 million ($7.65 per boe) in the same periods of 2022. These increases are primarily due to inflationary pressures and, for the nine months ended September 30, 2023, higher volumes from the Stickney Amalgamation.

For the three months ended September 30, 2023, transportation and processing increased to $24.0 million ($4.51 per boe) from $17.9 million ($3.91 per boe) in the same quarter of 2022. Transportation and processing increased to $61.7 million ($4.16 per boe) for the nine months ended September 30, 2023 from $49.6 million ($4.05 per boe) during the same period of 2022. The increases are primarily due to increased production volumes. The per boe increase was a result of increased tariffs on certain take-or-pay arrangements.

Lloydminster Heavy Oil

Production for the Lloydminster Heavy Oil segment for the three months ended September 30, 2023, increased to 51,482 boe per day from 38,260 boe per day as compared to same period of 2022. This increase is primarily due to the addition of properties acquired through the Serafina Acquisition which contributed approximately 26,500 boe per day in the three months ended September 30, 2023 compared to approximately 13,100 boe per day in the same period of 2022.

Production for the nine months ended September 30, 2023 increased to 54,247 boe per day from 26,230 boe per day in the same period of 2022. The increase is primarily due to the addition of properties acquired through the Caltex Amalgamation and the Serafina Acquisition which contributed approximately 41,000 boe per day for the nine months ended September 30, 2023 compared to approximately 13,400 boe per day for the same period of 2022.

Oil and natural gas sales net of blending increased to $453.4 million ($92.66 per boe) during the three months ended September 30, 2023 compared to $340.1 million ($93.38 per boe) for the same period of 2022. The increase is primarily due to higher sales volumes as well as lower blending cost as a result of lower benchmark condensate pricing. The per boe decrease is the result of lower benchmark commodity prices.

Oil and natural gas sales net of blending increased to $1,245.9 million ($82.23 per boe) during the nine months ended September 30, 2023 compared to $731.3 million ($99.82 per boe) for the same period in 2022. The increase on a dollar basis is primarily due to production from properties acquired through the Caltex Amalgamation and the Serafina Acquisition. The per boe decrease is the result of lower benchmark commodity prices.

The reduction in benchmark commodity prices also impacted royalties. The effective royalty rate for the three and nine months ended September 30, 2023 decreased to 12.2% and 10.7%, respectively, from 13.8% and 15.4% in the same periods of 2022.

Energy related production and operating costs for the three and nine months ended September 30, 2023 increased to $27.4 million ($5.60 per boe) and $89.1 million ($5.88 per boe), respectively, from $20.3 million ($5.57 per boe) and $37.5 million ($5.12 per boe) for the same periods in 2022. The increases are primarily attributable to the incremental production from properties acquired through Serafina Acquisition offset by lower natural gas prices.

Non-energy related production and operating costs for the three and nine months ended September 30, 2023 increased to $57.6 million ($11.77 per boe) and $165.7 million ($10.94 per boe), respectively, from $28.5 million ($7.83 per boe) and $78.6 million ($10.73 per boe) in the same periods of 2022. The increases are primarily due to the incremental production from properties acquired through the Caltex Amalgamation and the Serafina Acquisition and inflationary pressures on maintenance and other costs.

For the three months ended September 30, 2023, transportation and processing increased to $71.9 million ($14.69 per boe) from $28.8 million ($7.91 per boe) in the same quarter of 2022. Transportation and processing increased to $228.3 million ($15.07 per boe) for the nine months ended September 30, 2023 from $38.6 million ($5.27 per boe) during the same period of 2022. The increases are primarily due to the addition of legacy Serafina and Caltex oil volumes which are transported to their respective sales points by rail and truck resulting in higher transportation costs per barrel than legacy Strathcona heavy oil volumes which are transported by pipeline.

Montney

Production at the Company's Montney segment for the three and nine months ended September 30, 2023 increased to 37,800 boe per day and 36,503 boe per day, respectively, from 30,618 boe per day and 32,952 boe per day in the same periods of 2022. These increases are the result of strong well results from the 2022 and 2023 drilling programs at Kakwa.

For the three and nine months ended September 30, 2023, oil and natural gas sales decreased to $139.3 million ($40.06 per boe) and $397.7 million ($39.91 per boe), respectively, from $140.6 million ($49.91 per boe) and $503.9 million ($56.01 per boe) in the same periods of 2022. These decreases were primarily driven by lower benchmark commodity prices, offset by increased production.

The reduction in benchmark commodity prices also impacted royalties. For the three and nine months ended September 30, 2023, royalties as a percentage of sales decreased to 9.7% and 9.8%, respectively, from 17.1% and 12.7% in the same periods of 2022.

Non-energy related production and operating costs increased to $15.3 million ($4.40 per boe) for the three months ended September 30, 2023 from $12.7 million ($4.51 per boe) in the same quarter of 2022. On a dollar basis, the increase is primarily due to inflationary pressures on maintenance and other costs. On a per boe basis, the reduction in operating costs are attributable to the relatively fixed nature of the expenses combined with the higher production in third quarter of 2023 versus the third quarter of 2022.

Non-energy related production and operating costs increased to $46.0 million ($4.61 per boe) for the nine months ended September 30, 2023 from $40.2 million ($4.47 per boe) in the same period of 2022. The increase is primarily due to increased production and inflationary pressures on maintenance and other costs.

Transportation and processing costs increased to $18.6 million ($5.35 per boe) for the three months ended September 30, 2023 from $16.9 million ($6.00 per boe) in the same quarter of 2022. For the nine months ended September 30, 2023, the transportation and processing cost increased to $57.2 million ($5.74 per boe) from $54.9 million ($6.10 per boe) in the same period of 2022. On a dollar basis, the increase in transportation and processing costs are primarily attributable to increased volumes. On a per boe basis, the decrease is primarily the result of access to additional pipeline capacity in 2023 allowing previously trucked condensate volumes to be shipped by pipeline to sales points.

Corporate and Eliminations

Condensate produced from Strathcona’s Montney segment economically offsets consumption at the Cold Lake Thermal and Lloydminster Heavy Oil segments. Strathcona utilizes Company production internally when it is economically beneficial to do so as compared to purchasing third party production. Average daily sales volumes, oil and natural gas sales and blending costs represent the elimination of these intersegment transactions.

CAPITAL RESOURCES

Bank Credit Facilities

Covenant-Based Revolving Credit Facility

At September 30, 2023, the Company had a covenant-based revolving credit facility of $2.0 billion (December 31, 2022 - $2.0 billion) with a syndicate of Canadian, U.S. and international banks (the "**Revolving Credit Facility**"). The Revolving Credit Facility was increased to $2.3 billion on October 3, 2023 in connection with the Pipestone Acquisition. Refer to the "Recent Developments" section of this MD&A for further information.

The Revolving Credit Facility has a maturity date of February 27, 2026. There are no mandatory payments on the Revolving Credit Facility. In addition, the covenant-based Revolving Credit Facility is not a borrowing base facility and does not require annual or semi-annual reviews.

The Revolving Credit Facility bears interest at the applicable prime lending rate, base rate, bankers' acceptance 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 Revolving Credit Facility is secured by a floating charge debenture on the assets of the Company and its subsidiaries.

At September 30, 2023, the Company had letters of credit outstanding under the Revolving Credit Facility of $10.6 million (December 31, 2022 - $12.5 million).

Term Credit Facility

At September 30, 2023, the Company had a $525.0 million term loan (December 31, 2022 - $700.0 million) with a syndicate of Canadian banks (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**"). The Term Credit Facility has a maturity date of February 29, 2024.

Concurrent with the Arrangement (refer to the "Recent Developments" section of this MD&A for further information), the mandatory repayment provisions for the Term Credit Facility were amended. For the third quarter of 2023, an amortization payment of $175.0 million plus 100% of excess cash flow is due by November 15, 2023. Excess cash flow is calculated as Adjusted EBITDA (as defined below) less cash capital and decommissioning expenditures, lease payments (to the extent not already deducted), taxes, interest expense, amortization payments and any extraordinary and non-recurring losses added back in the determination of Adjusted EBITDA. For the fourth quarter of 2023, an amortization payment of $175.0 million is due by February 15, 2024. Mandatory prepayments are also required using 50% of the net cash proceeds from the issuance of shares or hybrid securities, certain debt issuances and certain asset sales. Payments made immediately reduce the Term Credit Facility.

The Revolving Credit Facility may be used to repay amounts owing on the Term Credit Facility if there is availability of $150.0 million after such payment.

The Term Credit Facility is secured by a floating charge debenture on the assets of the Company and its subsidiaries.

Foreign Exchange Risk Management on U.S. Denominated 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 eliminated at the time of borrowing as cross-currency interest rate swap contracts fix the principal and interest payments due at maturity. The terms of the Revolving Credit Facility and the Term Credit Facility allow the Canadian dollar equivalent of U.S. borrowings to exceed contracted amounts due to fluctuations in foreign exchange, provided that settlement amounts have been fixed upfront using cross-currency interest rate swap contracts. 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 September 30, 2023 the cross-currency swap liability was $2.9 million (December 31, 2022 – $4.3 million asset) and total debt includes an unrealized gain of $3.2 million (December 31, 2022 – unrealized loss of $5.9 million) related to U.S. borrowings on the Credit Facilities. Unrealized gains or losses on U.S. borrowings and offsetting unrealized gains or losses on cross-currency swap assets are included in foreign exchange gains in the interim financial statements.

As at September 30, 2023, the Company had cross-currency interest rate swap contracts outstanding totaling.

Notional (US$)	Maturity Date	Contract Price
384.3 million	October 11, 2023	CAD/USD 1.3661

Financial Covenants

At September 30, 2023, the Revolving Credit Facility and Term Credit Facility had three financial covenants which are calculated quarterly (as set out below). The financial covenant calculations under the Revolving Credit Facility and Term Credit Facility credit agreements (the "**Credit Agreements**") are identical.

(i) Total Debt to Adjusted EBITDA Ratio – All debt excluding the Financing Agreement (see Note 4 of the interim financial statements), capital leases and letters of credit constituting debt ("**Total Debt**"), each as defined in the Credit Agreements 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 Agreements (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 Agreements, 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 Agreements.

The Company was in compliance with its September 30, 2023 financial covenants, which are pro forma the Arrangement described in the "Recent Developments" section of this MD&A, and are summarized in the following table.

As at	September 30, 2023
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)[1]	**1.63**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)[1]	**1.26**
Interest Coverage Ratio (≥ 3.50)[1]	**8.01**

[1] See "Specified Financial Measures" section of this MD&A.

Senior Notes

At September 30, 2023, Strathcona had $678.9 million (December 31, 2022 - $677.7 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, after August 1, 2023 at the following redemption prices.

Date	Price
August 1, 2023	**105.156 %**
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

At September 30, 2023, the Company had a $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 letters of credit outstanding under the LC Facility do not impact the Company's borrowing capacity under the Revolving Credit Facility. At September 30, 2023, the Company had letters of credit in the amount of $54.5 million (December 31, 2022 - $52.6 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 Revolving Credit Facility to fund its capital requirements, including its working capital deficiency, and provide liquidity. Future liquidity depends primarily on Funds from Operations, availability on the Revolving Credit Facility and the ability to access debt and equity markets. The Term Credit Facility has amortization payments due November 15, 2023 and February 15, 2024 and a maturity date of February 29, 2024. The Revolving Credit Facility may be used to repay amounts owing on the Term Credit Facility if there is at least $150.0 million of unutilized credit after such payment. All repayments of principal on the Revolving Credit Facility are due at its maturity date in February 2026.

The availability under the Credit Facilities, net of cash, is summarized in the following table.

As at	**September 30, 2023**	December 31, 2022
Credit capacity	**2,525.0**	2,700.0
Credit Facilities debt at period end exchange rate	**(2,141.2)**	(2,408.3)
Unrealized (gain) loss on U.S. borrowings	**(3.2)**	5.9
Letters of credit outstanding	**(10.6)**	(12.5)
Availability	**370.0**	285.1
Cash	**—**	34.3
Availability under Credit Facilities, net of cash	**370.0**	319.4

The Company carries a working capital deficiency as part of its current capital structure. As at September 30, 2023, the working capital deficiency was $252.5 million (December 31, 2022 - $295.3 million) (a non-GAAP financial measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A). Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Company to meet its current and future obligations, to make scheduled principal and 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 sources of capital will not be necessary. The Company's cash flow and the development of projects are dependent on factors discussed in the "Risk Factors" section of this MD&A.

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 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.

DECOMMISSIONING LIABILITY

At September 30, 2023, Strathcona's discounted decommissioning provision balance was $353.6 million (December 31, 2022 - $291.5 million) for future abandonment and reclamation of the Company's oil and natural gas properties. The increase is primarily attributed to changes in estimates of $64.0 million relating to a decrease in the credit-adjusted discount rate to 8.00% at September 30, 2023 from 9.60% at December 31, 2022.

Effective December 31, 2022, Strathcona voluntarily changed its accounting policy with respect to its decommissioning provision to utilize a credit-adjusted discount rate. As a result, certain comparative figures have been restated. Refer to "Changes in Accounting Policies" section of this MD&A.

During the nine months ended September 30, 2023, the Company incurred $23.8 million of decommissioning expenditures compared to $18.7 million in the same period of 2022.

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 September 30, 2023.

	Total	<1 year	1-3 years	4-5 years	> 5 years
Revolving Credit Facility(1)	**1,619.4**	—	1,619.4	—	—
Term Credit Facility(2)	**539.7**	539.7	—	—	—
Senior Notes(3)	**818.9**	46.7	772.2	—	—
Accounts payable and accrued liabilities	**700.4**	700.4	—	—	—
Risk management contract liability	**296.1**	280.0	16.1	—	—
Lease and other obligations(4)	**419.9**	46.1	99.1	81.6	193.1
Total	**4,394.4**	1,612.9	2,506.8	81.6	193.1

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

(2) Contractual amount reflects contracted settlement price on cross-currency interest rate swap contracts ($525.0 million) and includes estimated interest payments ($14.7 million).

(3) Amounts represent repayment of the Senior Notes ($678.9 million) and associated interest payments ($140.0 million) based on foreign exchange rate in effect on September 30, 2023.

(4) Amounts relate to undiscounted payments for lease and other obligations. The estimation of future cash payments related to other obligations are subject to forecast lending rates and timing of exercise of the repurchase option under the Financing Agreement, which is assumed to be exercised on January 1, 2029. See Note 5 of the interim financial statements.

As at September 30, 2023, 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	**1,283.5**	200.8	336.8	228.9	517.0
Capital commitments	**66.6**	51.4	15.2	—	—
Other	**11.4**	3.8	5.7	1.9	—
Total	**1,361.5**	256.0	357.7	230.8	517.0

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 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 which are not disclosed in the notes to the annual financial statements.

SHARE CAPITAL

At September 30, 2023, the authorized capital of the Company consisted of an unlimited number of voting Class A common shares, an unlimited number of voting Class B common shares and an unlimited number of preferred shares. Pursuant to the Arrangement, Strathcona shareholders received 0.089278 common shares of AmalCo for each Strathcona Class A common share or Class B common share held. Following completion of the Arrangement on October 3, 2023, the authorized capital of AmalCo consists of an unlimited number of voting common shares and an unlimited number of preferred shares. Refer to the "Recent Developments" section of this MD&A for further information.

The following table summarizes the number of shares outstanding as at September 30, 2023, prior to completion of the Arrangement, and November 13, 2023, following completion of the Arrangement.

Share Class (millions)	**Shares Outstanding at September 30, 2023**	**Shares Outstanding at November 13, 2023**
Preferred shares	nil	nil
Class A Common Shares	932.6	nil
Class B Common Shares	1,254.1	nil
Common Shares	nil	214.2
Balance outstanding	**2,186.7**	**214.2**

The Company had no outstanding securities which were convertible into shares as at September 30, 2023 or November 13, 2023.

RELATED PARTY TRANSACTIONS

For the nine months ended September 30, 2023, there were no related party transactions.

On January 31, 2022, Strathcona exchanged $30.9 million of its shares in its investment in Stickney with an affiliate of WEF ("**WEF Fund II**") for shares of Caltex.

On January 31, 2022, Strathcona issued an unsecured, interest-bearing loan in the amount of $25.0 million to Stickney. The loan was extinguished upon the Caltex and Stickney Amalgamation.

On March 11, 2022, Strathcona acquired the remaining interests in Caltex and Stickney from WEF Fund II for share consideration valued at $295.8 million and $242.0 million respectively, and amalgamated with the entities.

Prior to the March 11, 2022 amalgamations, the Company provided management and administrative services to Caltex and Stickney. The fees received pursuant to this agreement from January 1, 2022 to March 11, 2022 totaled $0.6 million for Stickney and $1.3 million for Caltex.

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 judgments in preparing the financial statements are discussed in Note 2 of the annual financial statements. There have been no material changes to Strathcona's critical accounting estimates and judgments during the nine months ended September 30, 2023.

CHANGES IN ACCOUNTING POLICIES

Voluntary change in accounting policy

As detailed in Note 2 of the annual financial statements, effective December 31, 2022, the Company voluntarily changed its accounting policy with respect to its decommissioning provision to utilize a credit adjusted discount rate to determine the discounted amount of the liability presented at each balance sheet date. The Company previously utilized a risk-free discount rate to determine the discounted amount of its decommissioning liability. Concurrent with the voluntary accounting policy change, there was also an impact to depletion expense recorded in the respective periods due to change in estimated present value of future development costs at each period end for purposes of unit-of-production calculations.

This voluntary change in accounting policy was applied retrospectively and the effect of this change is described below. Comparative amounts in the interim financial statements have been restated as a result of these changes.

Reconciliation of the Condensed Consolidated Interim Statements of Income and Comprehensive Income

For the Three Months Ended September 30,	2022		
	Prior to accounting policy change	Effect of change	Restated
Depletion, depreciation and amortization	136.3	(39.8)	96.5
Finance costs	8.6	(0.3)	8.3
Deferred tax recovery	(212.4)	21.4	(191.0)
Net income	587.6	18.7	606.3
Net income per share			
Basic and Diluted	0.27	0.01	0.28

For the Nine Months Ended September 30,	2022		
	Prior to accounting policy change	Effect of change	Restated
Depletion, depreciation and amortization	338.6	(87.3)	251.3
Finance costs	21.6	(0.5)	21.1
Deferred tax recovery	(435.5)	21.4	(414.1)
Net income	1,229.6	66.4	1,296.0
Net income per share			
Basic and Diluted	0.58	0.03	0.61

Reconciliation of the Condensed Consolidated Interim Statements of Cash Flows

For the Three Months Ended September 30,	2022		
	Previous accounting policy	Effect of change	Restated
Net income	587.6	18.7	606.3
Items not involving cash	(266.9)	(18.7)	(285.6)

For the Nine Months Ended September 30,	2022		
	Previous accounting policy	Effect of change	Restated
Net income	1,229.6	66.4	1,296.0
Items not involving cash	(309.0)	(66.4)	(375.4)

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. Refer to the “Risk Factors” section in each of Appendix H - "*Information Concerning Strathcona Resources Ltd."* and Appendix I - "*Information Concerning AmalCo After Giving Effect to the Arrangement*" to the management information circular of Pipestone dated August 25, 2023, regarding the special meeting of the shareholders of Pipestone held on September 27, 2023, with respect to the Arrangement (the "**Arrangement Circular**"), which is available at www.sedarplus.ca.

SUMMARY OF QUARTERLY RESULTS

	2023			2022				2021
($ millions, unless otherwise indicated)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Operating results (boe/d)								
Average production volumes	**147,461**	143,778	144,160	143,371	119,829	111,153	82,535	74,648
Average sales volumes	**148,874**	143,239	146,877	141,595	119,992	110,430	81,357	68,643
Financial Results								
Oil and natural gas sales	**1,300.2**	1,112.8	1,047.7	1,124.9	1,112.6	1,331.5	774.4	521.5
Net Income (loss)(2)	**(41.1)**	274.1	90.5	62.2	606.3	349.7	340.0	248.3
Net income per share(2)	**(0.02)**	0.13	0.04	0.03	0.28	0.16	0.17	0.13
Cash flow from operating activities	**430.5**	343.1	181.1	482.2	373.5	391.9	207.7	126.0
Operating Earnings(1)	**289.9**	201.4	55.0	166.4	284.3	405.1	227.3	135.3
Funds from Operations(1)	**425.3**	389.2	276.9	308.1	322.9	393.4	209.5	86.7
Free Cash Flow(1)	**154.5**	152.2	34.9	69.1	154.8	253.6	101.1	(7.3)
Field Operating Income(1)	**549.6**	460.8	315.9	395.1	432.4	538.2	320.8	228.0
Field Operating Netback ($/boe)(1)	**40.13**	35.35	23.90	30.33	39.16	53.55	43.81	36.15
Capital expenditures	**260.2**	231.7	228.7	228.5	157.5	136.8	98.1	90.6
Decommissioning expenditures	**7.1**	4.9	12.1	4.5	8.3	1.4	9.0	3.4
Total assets(2)	**9,588.9**	9,451.2	9,289.5	9,164.5	9,416.3	6,091.0	6,047.4	3,838.8
Debt	**2,787.6**	2,898.2	3,041.7	3,044.1	3,545.9	1,213.4	1,472.5	911.5
Total equity	**4,526.4**	4,567.5	4,292.7	4,202.2	4,088.9	3,594.6	3,269.6	2,304.9
Common shares outstanding, end of period	**2,186.7**	2,186.7	2,186.5	2,186.5	2,186.6	2,186.6	2,185.8	1,944.8

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

(2) Effective December 31, 2022, Strathcona voluntarily changed its accounting policy with respect to its decommissioning provision to utilize a credit adjusted discount rate, which was applied retrospectively. As a result, certain comparative figures have been restated. Refer to “Changes in Accounting Policies” section of this MD&A.

Over the past eight quarters, the Company's oil and natural gas sales have fluctuated due to the acquisitions as described in the “Description of Business” section of this MD&A and note 4 of the annual financial statements, volatility in the crude oil, condensate and natural gas benchmark prices, changes in production and fluctuations in corporate oil price differentials. The Company's production has fluctuated due to 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 acquisitions as described in the “Description of Business” section of this MD&A and note 4 of the annual financial statements, 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 this period 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 the acquisitions as described in the “Description of Business” section of this MD&A and note 4 of the annual financial statements.

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”, “Effective royalty rate”, “Working Capital Deficiency”, “Field Operating Income”, “Field Operating Netback”, “Funds from Operations”, “Free Cash Flow”, “Operating Earnings”, “Senior Debt”, “Total Debt”, “Adjusted EBITDA” and “Interest Coverage Ratio” which are not recognized measures under generally accepted accounting principles (“**GAAP**”) and do not have a standardized meaning prescribed by IFRS. 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”, “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 “**Working Capital Deficiency**” is calculated by taking certain current assets including cash, accounts receivable, inventory and prepaid expenses and deposits less accounts payable and deferred revenue. Management uses this metric to manage the Company’s capital and cash flow requirements.

($ millions, unless otherwise indicated)	**September 30, 2023**	December 31, 2022
Cash	**—**	34.3
Accounts receivable	**384.0**	299.1
Inventory	**41.6**	64.2
Prepaid expenses and deposits	**29.1**	10.0
Accounts payable	**(700.4)**	(652.9)
Deferred revenue	**(6.8)**	(50.0)
Working Capital Deficiency	**(252.5)**	(295.3)

The term “**Oil and natural gas sales, net of blending**” is calculated by deducting sales of 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 Company 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 blending cost from sales and dividing by the respective sales volume. This ratio is useful to management when analyzing realized pricing against benchmark commodity prices.

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

“**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.

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

($ millions, unless otherwise indicated)	Three Months Ended **September 30, 2023**	 September 30, 2022	 June 30, 2023	Nine Months Ended **September 30, 2023**	 September 30, 2022
Oil and natural gas sales	**1,300.2**	1,112.6	1,112.8	**3,460.7**	3,218.5
Sales of purchased products	**7.2**	3.9	14.0	**35.0**	46.5
Purchased product	**(6.8)**	(3.9)	(14.6)	**(36.2)**	(47.2)
Blending costs	**(238.5)**	(238.5)	(249.8)	**(773.5)**	(771.8)
Oil and natural gas sales, net of blending	**1,062.1**	874.1	862.4	**2,686.0**	2,446.0
Royalties	**202.7**	170.6	106.2	**422.0**	531.8
Production and operating	**195.3**	153.3	190.6	**590.5**	425.5
Transportation and processing	**114.5**	63.6	104.8	**347.2**	143.1
Acquired inventory	**—**	54.2	—	**—**	54.2
Field Operating Income	**549.6**	432.4	460.8	**1,326.3**	1,291.4
Field Operating Netback ($/boe)	**40.13**	39.16	35.35	**33.21**	45.66

“**Operating Earnings**” is considered a key financial metric for evaluating the profitability of Strathcona’s principal business and is derived from (loss) income and comprehensive (loss) income 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 (loss) income and comprehensive (loss) income adjusted for non-cash items and transaction costs.

“**Free Cash Flow**” indicates funds available for deleveraging, funding future growth, or, at some point in the future, shareholder returns. Free Cash Flow is derived from (loss) income and comprehensive (loss) income 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, (loss) income and comprehensive (loss) income, is set forth below.

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2023**	September 30, 2022	June 30, 2023	**September 30, 2023**	September 30, 2022
(Loss) income and comprehensive (loss) income	**(41.1)**	606.3	274.1	**323.5**	1,296.0
Loss (gain) on risk management contracts	**265.8**	(183.3)	(142.1)	**59.5**	111.1
Foreign exchange loss (gain)	**16.9**	50.0	(12.2)	**(1.2)**	61.8
Transaction related costs	**3.5**	2.3	0.4	**5.1**	5.2
Unrealized loss on Sable remediation fund	**0.2**	—	0.1	**0.1**	0.7
Share of equity investment income	**—**	—	—	**—**	(11.3)
Gain on step acquisitions of equity method investee	**—**	—	—	**—**	(132.1)
Loss on termination of lease liability	**—**	—	—	**—**	1.4
Current income tax recovery	**—**	—	—	**(46.9)**	—
Deferred tax expense (recovery)	**44.6**	(191.0)	81.1	**206.2**	(414.1)
Operating Earnings	**289.9**	284.3	201.4	**546.3**	918.7
Depletion, depreciation and amortization	**171.6**	96.5	170.7	**505.4**	251.3
Finance costs	**18.1**	8.3	17.8	**53.7**	21.1
Other income - ARO government grant	**—**	(1.2)	—	**(0.3)**	(3.5)
Current income tax recovery	**—**	—	—	**46.9**	—
Gain on termination of lease liability	**—**	—	—	**—**	(1.8)
Loss on risk management contracts - realized	**(56.1)**	(68.1)	(0.4)	**(61.9)**	(262.8)
Foreign exchange gain (loss) - realized	**1.8**	3.1	(0.3)	**1.3**	2.8
Funds from Operations	**425.3**	322.9	389.2	**1,091.4**	925.8
Capital expenditures	**(260.2)**	(157.5)	(231.7)	**(720.6)**	(392.4)
Decommissioning costs	**(7.1)**	(8.3)	(4.9)	**(24.1)**	(18.7)
Transaction related costs	**(3.5)**	(2.3)	(0.4)	**(5.1)**	(5.2)
Free Cash Flow	**154.5**	154.8	152.2	**341.6**	509.5

Supplementary Financial Measures

The terms “Production and operating – Energy” and “Production and operating – Non-energy” are supplementary financial measures as they refer to portions of production and operating expenses. Non-energy operating expenses reflect the cost of operating activities relating to the production of resources. Energy operating expenses reflect the cost of gas and propane fuel, utilities and carbon tax incurred to operate facilities.

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

The term “Crown royalties”, “Freehold royalties” and “Gross over-riding royalties” are supplementary financial measures as they refer to portions of royalty expenses. Crown royalties reflect the cost of royalties paid for production on land where petroleum oil and natural gas rights are owned by government bodies. Freehold royalties reflect the cost of royalties paid for production on land where petroleum oil and natural gas rights are owned by private individuals or entities. Gross over-riding royalties reflect the cost of royalties paid to third parties when the WCS heavy oil benchmark exceeds US$60.00/bbl.

The term “Transportation expense” and “Processing expense” are supplementary financial measures as they refer to portions of transportation and processing expenses. Transportation expenses reflect the cost of transporting oil and natural gas to the sales point. Processing expenses reflect costs incurred to refine produced volumes to meet sales specifications.

The term “Depletion expense” and “Depreciation expense” are supplementary financial measures as they refer to portions of depletion, depreciation and amortization expenses. Depletion expenses reflect the cost of development of oil and natural gas reserves. Depreciation expense reflects the cost of a fixed asset over its expected useful life.

Financial Covenant Calculations

Total Debt and Senior Debt are defined in the Credit Facilities for financial covenant purposes, and are calculated as follows.

($ millions, unless otherwise indicated)	As at September 30, 2023
Revolving Credit Facility	**1,619.4**
Term Credit Facility	**521.8**
Unrealized gain (loss) on SOFR loans	**3.2**
Pipestone debt assumed	**179.0**
Senior Debt	**2,323.4**
Senior Notes	**678.9**
Total Debt	**3,002.3**

Adjusted EBITDA is defined in the Credit Facilities for financial covenant purposes, and is calculated on a trailing 12-month basis, as follows.

($ millions, unless otherwise indicated)	Trailing 12-months ended September 30, 2023
Net income	**385.7**
Adjusted for	
Interest and finance costs	**266.9**
Unrealized gain on commodity contracts	**58.9**
Depletion, depreciation, amortization and impairment	**649.8**
Unrealized foreign exchange loss	**(15.1)**
Unrealized gain on Sable remediation fund	**0.1**
Income tax expense	**201.5**
ARO government grants	**(1.8)**
IFRS 16 adjustment	**(20.4)**
EBITDA from Pipestone assets	**307.8**
Non-recurring losses	**11.1**
Adjusted EBITDA	**1,844.5**

Interest Charges are defined in the Credit Facilities for financial covenant purposes and are calculated on a trailing 12-month basis, as follows.

($ millions, unless otherwise indicated)	Trailing 12-months ended September 30, 2023
Interest on debt	**204.5**
Other adjustments(1)	**25.9**
Interest Charges	**230.4**

(1) Other adjustments include interest on finance leases, as defined in the Credit Facilities, and interest adjustments related to material acquisitions.

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 (comprised of 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, collectively, conventional natural gas.

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 2023 and 2024 production and capital spending guidance; the Company's use of hedging arrangements; the Company's ability to meet current and future obligations, including making scheduled principal and interest payments and to fund the other needs of the business; the timing and amount of amortization payments due under the Term Credit Agreement; future liquidity and financial capacity; anticipated proceeds from financial instruments, including commodity contracts; sources of funding for the Company's capital program and the terms of Strathcona's future contractual obligations, including its obligations under the Credit Agreements 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; 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. In addition, certain forward-looking information with respect to the Company's 2024 capital budget assumes commodity prices and exchange rates of: US$80 / bbl WTI, assuming a US$15 / bbl WCS-WTI differential, 0.73 USD-CAD and C$3 / mcf 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 and the conflict in Israel, and other heightened geopolitical risks 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; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of the Company's acquisitions; incorrect assessment of the value of acquisitions; delays resulting from or inability to obtain required regulatory approvals; 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 each of Appendix H - "*Information Concerning Strathcona Resources Ltd*." and Appendix "I" – "*Information Concerning AmalCo After Giving Effect to the Arrangement*" to the Arrangement Circular, which is available at www.sedarplus.ca.

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 can be found at: www.sedarplus.ca and www.strathconaresources.com.