

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2026 AND 2025

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis ("**MD&A**") of the financial condition and results of operations for Strathcona Resources Ltd. (the "**Company**" or "**Strathcona**") is dated November 8, 2026 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, 2026 and 2025 (the "**interim financial statements**") and the Company's audited consolidated financial statements as at and for the years ended December 31, 2025 and 2024 (the "**annual financial statements**"). The interim financial statements have been prepared in accordance with IFRS® Accounting Standards (the "**Accounting Standards**") as issued by the International Accounting Standards Board, in Canadian dollars, except where indicated otherwise. The interim financial statements, annual financial statements and MD&A of Strathcona have been prepared by management, reviewed by the Audit Committee of the Company's Board of Directors and were approved by the Company's Board of Directors.

This MD&A contains forward-looking information; see "*Forward-Looking Information*" in this MD&A for further information. This MD&A also contains financial measures that do not have a standardized meaning under the Accounting Standards and may not be comparable to similar financial measures disclosed by other issuers; see "*Specified Financial Measures*" in this MD&A for further information. This MD&A contains certain oil and gas metrics and measures; see "*Advisories Regarding Oil & Gas Information*" at the end of this MD&A.

All dollar amounts are referenced in Canadian dollars and, in the case of amounts presented in tabular form, in millions of Canadian dollars, except when noted otherwise. All per unit figures are based on commodity sales volumes, net of blending. Sales volumes differ from production volumes resulting from changes in oil inventory.

DESCRIPTION OF BUSINESS

Strathcona is a corporation that exists under, and is governed by, the provisions of the *Business Corporations Act* (Alberta). Strathcona's common shares are listed on the Toronto Stock Exchange under the trading symbol "SCR". Following the disposition of its Montney business through the Groundbirch Asset Sale and the Kakwa and Grande Prairie Asset Sales in 2025 (each as defined and described under *"Presentation of Continuing and Discontinued Operations"* in this MD&A), Strathcona is a Calgary-based pure play heavy oil producer engaged in the acquisition, exploration, development and production of petroleum and natural gas reserves with operations focused on thermal oil and enhanced oil recovery. Strathcona's crude oil property interests are principally located in Western Canada, in the provinces of Alberta and Saskatchewan.

At the date of this MD&A, approximately 56.9% of the Company's common shares were owned by certain limited partnerships comprising Waterous Energy Fund (collectively, "**WEF**").

RECENT DEVELOPMENTS

On November 8, 2026, Strathcona entered into a definitive agreement to acquire all of the outstanding shares of Greenfire Resources Ltd. ("Greenfire") (the "Transaction"). For each Greenfire share, Greenfire shareholders may elect to receive either $11.00 in cash or 0.25 of a Strathcona share.

Strathcona expects to fund cash consideration of up to approximately $740 million and the repayment of Greenfire's outstanding indebtedness by drawing on its existing Credit Facilities.

WEF controls approximately 56.9% of Strathcona and 72.0% of Greenfire, so the Transaction is a related party transaction for Strathcona. WEF has entered into a binding agreement in which they have committed to, among other things, vote in favour of the Transaction and to elect to receive share consideration for their Greenfire shares. After closing, WEF is expected to own or control between 60% and 64% of Strathcona's outstanding shares.

The Transaction requires approval by each company's shareholders at special meetings expected in January 2027. This includes minority approval by a majority of votes cast by shareholders of each company at a special meeting to be called by each company, excluding WEF. It also requires court approval, *Competition Act* approval and satisfaction of other customary conditions. Closing is expected in the first quarter of 2027. For more details, see the Strathcona and Greenfire joint press release dated November 8, 2026.

PRESENTATION OF CONTINUING AND DISCONTINUED OPERATIONS

During the year ended December 31, 2025, the Company entered into three separate asset purchase and sale agreements to dispose of its Montney segment. The Montney segment represents a separate major line of business and geographical area of operations, therefore, its results have been classified as discontinued operations in accordance with IFRS 5 *Non-Current Assets Held for Sale and Discontinued Operations.*

Groundbirch Asset Sale

On June 1, 2025, the Company completed the sale of assets located primarily in the Groundbirch area in Northeast British Columbia (the "**Groundbirch Asset Sale**") for aggregate proceeds of $292 million, inclusive of closing adjustments, paid in common shares of Tourmaline Oil Corp. An associated gain on sale of assets of $138 million was recognized on close of the transaction.

Kakwa and Grande Prairie Asset Sales

On May 14, 2025, the Company entered into asset purchase and sale agreements pursuant to which the Company agreed to sell assets primarily located in the Kakwa and Grande Prairie areas in Northwest Alberta (the **"Kakwa and Grande Prairie Asset Sales**"). On July 2, 2025, the Company completed the Kakwa and Grande Prairie Asset Sales for total cash consideration of $2,399 million, inclusive of closing adjustments. An associated gain on sale of assets of $604 million was recognized on close of the transaction.

The financial results for the three and nine months ended September 30, 2026 and 2025 and the three months ended June 30, 2026, are presented below to reconcile continuing and discontinued operations to total results. Total results is a non-GAAP measure, which does not have a standardized meaning under the Accounting Standards and may not be comparable to similar financial measures disclosed by other issuers. Total results is used by management of Strathcona to assess the historical financial performance of the total business and is not intended to be indicative of future results of the Company.

($ millions, unless otherwise indicated)	Three Months Ended September 30, 2026			Three Months Ended September 30, 2025			Three Months Ended June 30, 2026		
	Cont.	Disc.	**Total**	Cont.	Disc.	**Total**	Cont.	Disc.	**Total**
Revenues and other income									
Oil and natural gas sales	1,459	—	**1,459**	1,009	3	**1,012**	1,486	—	**1,486**
Sale of purchased product	21	—	**21**	31	—	**31**	82	—	**82**
Royalties	(262)	—	**(262)**	(128)	—	**(128)**	(232)	—	**(232)**
Oil and natural gas revenues	1,218	—	**1,218**	912	3	**915**	1,336	—	**1,336**
Gain (loss) on risk management contracts	34	—	**34**	(27)	—	**(27)**	52	—	**52**
Midstream revenue	7	—	**7**	9	—	**9**	9	—	**9**
Other income	1	—	**1**	8	—	**8**	—	—	**—**
	1,260	—	**1,260**	902	3	**905**	1,397	—	**1,397**
Expenses									
Purchased product	21	—	**21**	31	—	**31**	80	—	**80**
Blending costs	332	—	**332**	222	—	**222**	417	—	**417**
Production and operating	188	—	**188**	145	(4)	**141**	171	—	**171**
Transportation and processing	104	—	**104**	92	—	**92**	96	—	**96**
General and administrative	23	—	**23**	24	(2)	**22**	26	—	**26**
Interest	28	—	**28**	23	—	**23**	29	—	**29**
Transaction related costs	2	—	**2**	4	15	**19**	1	—	**1**
Finance costs	9	—	**9**	14	—	**14**	10	—	**10**
Depletion, depreciation and amortization	150	—	**150**	151	—	**151**	140	—	**140**
Foreign exchange loss (gain)	2	—	**2**	17	—	**17**	(2)	—	**(2)**
Change in decommissioning liabilities	6	—	**6**	—	—	**—**	1	—	**1**
	865	—	**865**	723	9	**732**	969	—	**969**
Gain on marketable securities	—	—	**—**	22	—	**22**	—	—	**—**
Gain on sale of assets, net	—	—	**—**	—	616	**616**	—	—	**—**
Income before income taxes	395	—	**395**	201	610	**811**	428	—	**428**
Income tax expense	97	—	**97**	57	181	**238**	95	—	**95**
Income and comprehensive income	298	—	**298**	144	429	**573**	333	—	**333**

($ millions, unless otherwise indicated)	Nine Months Ended September 30, 2026			Nine Months Ended September 30, 2025		
	Cont.	Disc.	**Total**	Cont.	Disc.	**Total**
Revenues and other income						
Oil and natural gas sales	4,066	—	**4,066**	3,159	521	**3,680**
Sale of purchased product	107	—	**107**	53	—	**53**
Royalties	(636)	—	**(636)**	(336)	(35)	**(371)**
Oil and natural gas revenues	3,537	—	**3,537**	2,876	486	**3,362**
Gain (loss) on risk management contracts	15	—	**15**	(85)	—	**(85)**
Midstream revenue	25	—	**25**	16	—	**16**
Other income	1	—	**1**	14	—	**14**
	3,578	—	**3,578**	2,821	486	**3,307**
Expenses						
Purchased product	105	—	**105**	53	—	**53**
Blending costs	1,055	—	**1,055**	798	—	**798**
Production and operating	544	—	**544**	509	84	**593**
Transportation and processing	294	—	**294**	274	111	**385**
General and administrative	77	—	**77**	64	10	**74**
Interest	85	—	**85**	107	—	**107**
Transaction related costs	3	—	**3**	19	19	**38**
Finance costs	30	—	**30**	41	13	**54**
Depletion, depreciation and amortization	432	—	**432**	454	90	**544**
Foreign exchange loss (gain)	4	—	**4**	(23)	—	**(23)**
Change in decommissioning liabilities	20	—	**20**	—	—	**—**
Contingent consideration	42	—	**42**	—	—	**—**
	2,691	—	**2,691**	2,296	327	**2,623**
Gain on marketable securities	—	—	**—**	69	—	**69**
Gain on sale of assets, net	—	—	**—**	—	621	**621**
Loss on settlement of other obligations	—	—	**—**		(1)	**(1)**
Income before income taxes	887	—	**887**	594	779	**1,373**
Income tax expense	217	—	**217**	138	225	**363**
Income and comprehensive income	670	—	**670**	456	554	**1,010**

The following tables reconcile total operating earnings for the three and nine months ended September 30, 2026 and 2025 and the three months ended June 30, 2026.

($ millions, unless otherwise indicated)	Three Months Ended September 30, 2026			Three Months Ended September 30, 2025			Three Months Ended June 30, 2026		
	Cont.	Disc.	**Total**	Cont.	Disc.	**Total**	**Cont.**	**Disc.**	**Total**
Revenues									
Oil and natural gas sales	1,459	—	**1,459**	1,009	3	**1,012**	1,486	**—**	**1,486**
Sale of purchased product	21	—	**21**	31	—	**31**	82	**—**	**82**
Blending costs	(332)	—	**(332)**	(222)	—	**(222)**	(417)	**—**	**(417)**
Purchased product	(21)	—	**(21)**	(31)	—	**(31)**	(80)	**—**	**(80)**
Midstream revenue	7	—	**7**	9	—	**9**	9	**—**	**9**
Oil and natural gas sales, net of blending[1]	1,134	—	**1,134**	796	3	**799**	1,080	—	**1,080**
Expenses									
Royalties	262	—	**262**	128	—	**128**	232	**—**	**232**
Production and operating	188	—	**188**	145	(4)	**141**	171	**—**	**171**
Transportation and processing	104	—	**104**	92	—	**92**	96	**—**	**96**
Field operating income[1]	580	—	**580**	431	7	**438**	581	—	**581**
Depletion, depreciation and amortization	150	—	**150**	151	—	**151**	140	**—**	**140**
General and administrative	23	—	**23**	24	(2)	**22**	26	**—**	**26**
Finance costs	9	—	**9**	14	—	**14**	10	**—**	**10**
Other income	(1)	—	**(1)**	(8)	—	**(8)**	—	**—**	**—**
Interest	28	—	**28**	23	—	**23**	29	**—**	**29**
Operating earnings	371	—	**371**	227	9	**236**	376	—	**376**

($ millions, unless otherwise indicated)	Nine Months Ended September 30, 2026			Nine Months Ended September 30, 2025		
	Cont.	Disc.	**Total**	Cont.	Disc.	**Total**
Revenues						
Oil and natural gas sales	4,066	—	**4,066**	3,159	521	**3,680**
Sale of purchased product	107	—	**107**	53	—	**53**
Blending costs	(1,055)	—	**(1,055)**	(798)	—	**(798)**
Purchased product	(105)	—	**(105)**	(53)	—	**(53)**
Midstream revenue	25	—	**25**	16	—	**16**
Oil and natural gas sales, net of blending[1]	3,038	—	**3,038**	2,377	521	**2,898**
Expenses						
Royalties	636	—	**636**	336	35	**371**
Production and operating	544	—	**544**	509	84	**593**
Transportation and processing	294	—	**294**	274	111	**385**
Field operating income[1]	1,564	—	**1,564**	1,258	291	**1,549**
Depletion, depreciation and amortization	432	—	**432**	454	90	**544**
General and administrative	77	—	**77**	64	10	**74**
Finance costs	30	—	**30**	41	13	**54**
Other income	(1)	—	**(1)**	(14)	—	**(14)**
Interest	85	—	**85**	107	—	**107**
Operating earnings	941	—	**941**	606	178	**784**

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

PRODUCTION VOLUMES

	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Bitumen (bbl/d)	**64,776**	61,157	62,782	**62,990**	60,919
Heavy oil (bbl/d)	**58,294**	53,943	53,753	**55,594**	51,983
Condensate and light oil (bbl/d)	**61**	39	69	**69**	60
Total oil production (bbl/d)	**123,131**	115,139	116,604	**118,653**	112,962
Other NGLs (bbl/d)	**17**	4	12	**15**	17
Natural gas (mcf/d)	**2,030**	2,642	2,436	**2,244**	2,853
Total (boe/d) - continuing operations	**123,486**	115,584	117,022	**119,042**	113,455
Total (boe/d) - discontinued operations	**—**	617	—	**—**	50,317
Total (boe/d)	**123,486**	116,201	117,022	**119,042**	163,772
% liquids - continuing operations	**99.7 %**	99.6 %	99.7 %	**99.7 %**	99.6 %

Production volumes from continuing operations increased 7% (or 7,902 boe per day) for the three months ended September 30, 2026 to an average of 123,486 boe per day compared to 115,584 boe per day for the same period of 2025. The increase was primarily attributable to the acquisition of the Vawn thermal heavy oil asset in the fourth quarter of 2025 (the "**Vawn Acquisition**") which contributed average production of 7,459 boe per day during the third quarter of 2026 and the start up of the Meota Central facility in late July 2026, both at the Lloydminster Thermal segment, higher production at the Cold Lake segment, partially offset by lower production at the Lloydminster Conventional segment due to development challenges.

Production volumes from continuing operations increased 5% (or 5,587 boe per day) for the nine months ended September 30, 2026 to an average of 119,042 boe per day compared to 113,455 boe per day for the same period of 2025. The increase was primarily due to the Vawn Acquisition which contributed average production of 6,694 boe per day at the Lloydminster Thermal segment, higher production at the Cold Lake segment, partially offset by lower production at the Lloydminster Conventional segment due to development challenges.

Production volumes from continuing operations increased 6% (or 6,464 boe per day) during the three months ended September 30, 2026 to an average of 123,486 boe per day compared to 117,022 boe per day for the three months ended June 30, 2026. The increase was primarily due to the start up of the Meota Central facility at the Lloydminster Thermal segment and increased production at the Cold Lake segment.

SALES VOLUMES

	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Bitumen (bbl/d)	**64,917**	61,433	62,390	**63,057**	60,878
Heavy oil (bbl/d)	**58,683**	53,319	53,253	**55,940**	52,808
Condensate and light oil (bbl/d)	**61**	39	69	**69**	60
Total oil sales (bbl/d)	**123,661**	114,791	115,712	**119,066**	113,746
Other NGLs (bbl/d)	**17**	4	12	**15**	17
Natural gas (mcf/d)	**2,030**	2,642	2,436	**2,244**	2,853
Total (boe/d) - continuing operations	**124,016**	115,235	116,130	**119,455**	114,233
Total (boe/d) - discontinued operations	**—**	617	—	**—**	50,325
Total (boe/d)	**124,016**	115,852	116,130	**119,455**	164,558

Sales volumes typically trend with production volumes, except in cases of an inventory build or draw. Strathcona carries inventory on rail cars in transit to the U.S. Gulf Coast, on pipelines and in storage tanks.

For the three months ended September 30, 2026, there was a drawdown of pipeline inventory which increased overall sales volumes. For the nine months ended September 30, 2026, pipeline inventory was sold resulting in sales volumes exceeding production volumes.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI[(1)]	**85.79**	64.93	92.77	**83.50**	66.70
WCS Hardisty[(2)]	**71.90**	54.54	78.11	**69.26**	55.59
WCS USGC[(3)]	**80.25**	62.59	87.35	**77.60**	63.77
WTI-WCS Hardisty differential	**(13.89)**	(10.39)	(14.66)	**(14.24)**	(11.11)
WTI-WCS USGC differential	**(5.54)**	(2.34)	(5.42)	**(5.90)**	(2.93)
NYMEX-AECO differential (US$/MMbtu)[(4)]	**(1.96)**	(2.42)	(1.92)	**(2.43)**	(2.30)
Condensate differential[(5)]	**(3.42)**	(1.83)	2.68	**(0.42)**	(1.21)
Average Exchange rate (C$/US$)	**1.3988**	1.3774	1.3836	**1.3847**	1.3987
CAD$/bbl unless otherwise indicated					
WTI[(1)]	**119.98**	89.43	128.25	**115.63**	93.36
WCS Hardisty[(2)]	**100.56**	75.10	107.95	**95.91**	77.79
WCS USGC[(3)]	**112.24**	86.19	120.74	**107.47**	89.26
AECO 5A (C$/gj)[(6)]	**1.48**	0.60	1.55	**1.64**	1.42
Condensate par at Edmonton	**115.17**	86.91	131.96	**115.02**	91.65
AESO weighted average pool price (C$/MWh)[(7)]	**36.69**	51.84	30.12	**33.11**	44.77
CORRA (%)[(8)]	**2.29**	2.74	2.28	**2.28**	2.85

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

During the third quarter of 2026, WTI pricing averaged US$85.79 per bbl, an 8% decrease from the second quarter of 2026. The primary driver of this decrease was the temporary easing of geopolitical tensions.

The WTI-WCS USGC differential was relatively unchanged, when compared to the second quarter of 2026, widening by 2%. The WTI-WCS Hardisty differential narrowed by 5% in the third quarter of 2026, when compared to the second quarter of 2026, primarily due to limited egress constraints.

AECO 5A natural gas prices decreased in the third quarter of 2026 by 5%, when compared to the second quarter of 2026, primarily due to elevated natural gas storage inventories and ongoing transportation and offtake constraints.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales – Net of Blending

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2026**	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Bitumen blend	**829**	586	875	**2,351**	1,856
Heavy oil, blended and raw	**630**	423	610	**1,713**	1,301
Condensate and light oil	**—**	—	1	**1**	1
Natural gas	**—**	—	—	**1**	1
Oil and natural gas sales	**1,459**	1,009	1,486	**4,066**	3,159
Midstream revenue	**7**	9	9	**25**	16
Gain on purchased product	**—**	—	2	**2**	—
Bitumen – blending cost	**(269)**	(194)	(338)	**(858)**	(683)
Heavy oil – blending cost	**(63)**	(28)	(79)	**(197)**	(115)
Oil and natural gas sales, net of blending - continuing operations[(1)]	**1,134**	796	1,080	**3,038**	2,377
Oil and natural gas sales, net of blending - discontinued operations[(1)]	**—**	3	—	**—**	521
Oil and natural gas sales, net of blending[(1)]	**1,134**	799	1,080	**3,038**	2,898

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

Oil and natural gas sales, net of blending from continuing operations increased 42% (or $338 million) for the three months ended September 30, 2026 to $1,134 million compared to $796 million in the same period of 2025. This increase was primarily related to higher oil benchmark pricing and an increase in sales volumes, partially offset by increased blending costs due to higher condensate benchmark pricing.

Oil and natural gas sales, net of blending, from continuing operations increased 28% (or $661 million) for the nine months ended September 30, 2026 to $3,038 million compared to $2,377 million for the same period in 2025. This increase was primarily attributable to higher oil benchmark pricing, increased sales volumes and revenue contributions from the Hardisty Rail Terminal ("**HRT**") that was acquired in April 2025, partially offset by increased blending costs due to higher condensate benchmark pricing.

Oil and natural gas sales, net of blending from continuing operations increased 5% (or $54 million) for the three months ended September 30, 2026 to $1,134 million compared to $1,080 million for the three months ended June 30, 2026. This increase was primarily due to higher sales volumes and lower blending costs as the result of a decrease in condensate benchmark pricing, partially offset by weaker oil benchmark pricing.

Average Realized Prices

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Bitumen blend ($/bbl)[1]	**93.60**	69.32	94.61	**86.69**	70.55
Heavy oil, blended and raw ($/bbl)[1]	**105.03**	80.60	109.72	**99.42**	82.27
Condensate and light oil ($/bbl)	**103.73**	—	97.89	**87.49**	63.16
Realized oil ($/bbl)	**99.01**	74.53	101.56	**92.61**	75.98
Other natural gas liquids ($/bbl)	**—**	—	—	**—**	25.14
Natural gas ($/mcf)	**—**	1.12	—	**1.66**	1.75
Midstream revenue ($/bbl)	**0.67**	0.91	0.82	**0.78**	0.52
Combined ($/boe) - continuing operations	**99.45**	75.08	102.24	**93.18**	76.23
Combined ($/boe) - discontinued operations	**—**	58.34	—	**—**	37.90
Combined ($/boe)	**99.45**	74.97	102.24	**93.18**	64.50

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

For the three and nine months ended September 30, 2026, combined realized price from continuing operations increased 32% (or $24.37 per boe) and 22% (or $16.95 per boe), respectively, compared to the same periods of 2025. The increases were primarily attributable to higher average WCS Hardisty and USGC benchmark prices, partially offset by higher condensate benchmark pricing, which increased per barrel blending costs.

Combined realized price from continuing operations decreased 3% (or $2.79 per boe) for the three months ended September 30, 2026 compared to the three months ended June 30, 2026. This decrease was primarily attributable to lower average WCS Hardisty and USGC benchmark prices, partially offset by decreased per barrel blend costs as the result of lower condensate benchmark pricing.

ROYALTIES

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Crown royalties	**200**	107	158	**470**	267
Freehold royalties	**7**	6	9	**21**	18
Gross overriding royalties	**48**	9	57	**126**	33
Other royalties	**7**	6	8	**19**	18
Royalties - continuing operations	**262**	128	232	**636**	336
Royalties - discontinued operations	**—**	—	—	**—**	35
Royalties	**262**	128	232	**636**	371
Effective royalty rate (%) - continuing operations[1]	**23.1 %**	16.0 %	21.4 %	**20.9 %**	14.1 %

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

For the three and nine months ended September 30, 2026, the effective royalty rate from continuing operations increased to 23.1% and 20.9%, from 16.0% and 14.1%, respectively, in the comparable periods in 2025. These increases were primarily attributable to higher commodity benchmark pricing.

The effective royalty rate increased to 23.1% for the three months ended September 30, 2026, from 21.4% for the three months ended June 30, 2026. This increase was primarily due to higher full year forecasted commodity benchmark pricing which increased overall crown royalties, partially offset by a decrease in gross overriding royalties due to lower realized benchmark pricing in the quarter.

PRODUCTION AND OPERATING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Production and operating – Energy	**67**	38	62	**206**	171
Production and operating – Non-energy	**121**	107	109	**338**	338
Production and operating expenses - continuing operations	**188**	145	171	**544**	509
Production and operating expenses - discontinued operations	**—**	(4)	—	**—**	84
Production and operating expenses	**188**	141	171	**544**	593
Production and operating – Energy - continuing operations ($/boe)	**5.77**	3.65	6.03	**6.32**	5.47
Production and operating – Non-energy - continuing operations ($/boe)	**10.56**	10.09	10.32	**10.36**	10.85
Production and operating expenses - continuing operations ($/boe)	**16.33**	13.74	16.35	**16.68**	16.32

Production and operating expenses from continuing operations increased 30% (or $43 million) for the three months ended September 30, 2026 to $188 million ($16.33 per boe) from $145 million ($13.74 per boe) in the same period of 2025. Energy expenses increased by 76% (or $29 million) primarily due to an increase in fuel costs as the result of higher AECO pricing, increased carbon tax expense due to higher compliance obligations and as a result of the Vawn Acquisition, which contributed $5 million in energy costs. Non-energy expenses increased 13% (or $14 million) primarily due to the Vawn Acquisition, which contributed $5 million in costs, higher surface maintenance costs due to an increase in activity at the Cold Lake and Lloydminster Thermal segments and an increase in chemical costs at the Cold Lake segment.

Production and operating expenses from continuing operations increased 7% (or $35 million) for the nine months ended September 30, 2026 to $544 million ($16.68 per boe) from $509 million ($16.32 per boe) in the same period of 2025. Energy expenses increased by 20% (or $35 million) primarily due to an increase in fuel costs as the result of higher AECO pricing, an increase in carbon tax expense due to higher compliance obligations and the addition of $19 million in operating expenses as the result of the Vawn Acquisition. Non-energy expenses remained consistent for the nine months ended September 30, 2026, compared to the same period of 2025. Impacts included $16 million in operating costs associated with the Vawn Acquisition, partially offset by lower chemical and surface maintenance costs at both the Cold Lake and Lloydminster Conventional segments.

Production and operating expenses from continuing operations increased 10% (or $17 million) for the three months ended September 30, 2026 to $188 million ($16.33 per boe) from $171 million ($16.35 per boe) for the three months ended June 30, 2026. Energy expenses increased 8% (or $5 million) primarily due to the Meota Central facility commencing operations and higher fuel costs, partially offset by a decrease in carbon tax expense due to emission related adjustments. Non-energy expenses increased 11% (or $12 million) primarily due to an increase in surface maintenance activity at all segments, higher chemical expenses at both the Cold Lake and Lloydminster Thermal segments, partially offset by a decrease in downhole maintenance at the Cold Lake segment.

TRANSPORTATION EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Transportation expenses - continuing operations	**104**	92	96	**294**	274
Transportation and processing expenses - discontinued operations	**—**	—	—	**—**	111
Transportation and processing expenses	**104**	92	96	**294**	385
$ per boe - continuing operations	**9.13**	8.67	9.08	**9.02**	8.79

Transportation expenses from continuing operations increased 13% (or $12 million) for the three months ended September 30, 2026 to $104 million ($9.13 per boe) compared to $92 million ($8.67 per boe) in the same period of 2025. This increase was primarily attributable to increased sales volumes at the Cold Lake and Lloydminster Thermal segments, higher rail transportation costs resulting from increased fuel charges and the utilization of make up rights at the Cold Lake segment in the comparable period of 2025. The Vawn Acquisition contributed $2 million to transportation costs in the current quarter.

Transportation expenses from continuing operations increased 7% (or $20 million) for the nine months ended September 30, 2026 to $294 million ($9.02 per boe) compared to $274 million ($8.79 per boe) in the same period of 2025. This increase was primarily attributable to increased sales volumes at the Cold Lake segment, higher rail transportation costs resulting from increased fuel charges and the utilization of make up rights at the Cold Lake segment in the comparable period of 2025. The Vawn Acquisition contributed $6 million to transportation costs in the current year.

Transportation expenses from continuing operations increased 8% (or $8 million) for the three months ended September 30, 2026 to $104 million ($9.13 per boe) from $96 million ($9.08 per boe) in the three months ended June 30, 2026. This increase was primarily attributable to increased sales volumes at the Lloydminster Thermal segment.

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

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Depletion expense	**141**	142	131	**406**	426
Depreciation and amortization expense	**9**	9	9	**26**	28
DD&A - continuing operations	**150**	151	140	**432**	454
DD&A - discontinued operations	**—**	—	—	**—**	90
DD&A	**150**	151	140	**432**	544
$ per boe - continuing operations	**13.21**	14.27	13.22	**13.26**	14.57

DD&A expense from continuing operations decreased 1% (or $1 million) for the three months ended September 30, 2026 to $150 million ($13.21 per boe) compared to $151 million ($14.27 per boe) for the same period of 2025. For the nine months ended September 30, 2026, DD&A expense from continuing operations decreased 5% (or $22 million) to $432 million ($13.26 per boe), compared to $454 million ($14.57 per boe) for the same period of 2025. These decreases were primarily due to an impairment loss of $376 million recorded at year end 2025 at the Lloydminster Conventional segment, which lowered the depletable base for certain fields.

DD&A expense from continuing operations, for the three months ended September 30, 2026, increased 7% (or $10 million) to $150 million ($13.21 per boe) compared to $140 million ($13.22 per boe) for the three months ended June 30, 2026. This increase was primarily due to higher sales volumes.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A")

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2026**	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
G&A expenses - continuing operations	**23**	24	26	**77**	64
G&A expenses - discontinued operations	**—**	(2)	—	**—**	10
G&A expenses	**23**	22	26	**77**	74
$ per boe - continuing operations	**2.03**	2.23	2.43	**2.36**	2.05

For the three months ended September 30, 2026, G&A expenses from continuing operations decreased 4% (or $1 million) compared to the same period of 2025. This decrease was primarily the result of lower professional fees in the current quarter.

For the nine months ended September 30, 2026, G&A expenses from continuing operations increased 20% (or $13 million) compared to the same period of 2025. This increase was primarily due to a higher annual Company bonus payment and the reallocation of corporate costs across the business following the sale of the Montney segment.

G&A expenses from continuing operations for the three months ended September 30, 2026 decreased 12% (or $3 million) compared to the three months ended June 30, 2026. This decrease was primarily due to lower professional fees in the current quarter.

INTEREST

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2026**	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Interest	**28**	23	29	**85**	107
Weighted average interest rate (%)	**4.8 %**	6.6 %	4.8 %	**4.7 %**	5.8 %

For the three months ended September 30, 2026, interest expense increased 22% (or $5 million) when compared to the same period of 2025. This increase was primarily attributable to higher overall debt balances, partially offset by lower interest rates. Debt balances decreased in 2025 following the sale of the Montney segment and increased at the end of 2025 after the special distribution. The Company's weighted average interest rate decreased following the repayment of the senior notes at the end of 2025.

For the nine months ended September 30, 2026, interest expense decreased 21% (or $22 million) when compared to the same period of 2025. This decrease was primarily attributable to lower interest rates and lower overall debt balances.

Interest expense decreased 3% (or $1 million) to $28 million for the three months ended September 30, 2026, compared to $29 million for the three months ended June 30, 2026. The decrease in interest expense was due to lower debt balances.

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

TAX POOLS

As at September 30, 2026, the Company had approximately $2,219 million (December 31, 2025 - $2,790 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, 2026**	December 31, 2025
Canadian oil and gas property expenditures[1]	10%	**320**	254
Canadian development expenditures[1]	30%	**348**	165
Canadian exploration expenditures[1]	100%	**9**	3
Undepreciated capital costs[2]	4% - 55%	**1,327**	1,232
Non-capital losses	100%	**177**	897
Other[3]		**38**	239
Total tax pools		**2,219**	2,790

(1) Amount is net of tax pools where deductibility is uncertain.
(2) As at September 30, 2026, approximately 93% (December 31, 2025 – 91%) of costs in this pool have an annual deduction rate of 25% or higher.
(3) "Other" tax pools are comprised of federal and provincial scientific research and experimental development expenditure pools and credits and financing costs.

CAPITAL EXPENDITURES

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

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2026**	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Drilling, completion and equipping	**97**	107	94	**323**	520
Facilities and pipelines	**118**	146	106	**352**	405
Recompletion, workovers and polymer powder	**12**	16	18	**46**	48
Capitalized G&A and other expenditures[1]	**12**	9	13	**45**	32
Capital expenditures[2]	**239**	278	231	**766**	1,005

(1) Comparative periods have been revised to exclude land expenditures from capital expenditures.
(2) Capital expenditures includes continuing and discontinued operations.

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

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2026**	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Cold Lake	**78**	97	69	**224**	284
Lloydminster Thermal	**123**	142	129	**411**	352
Lloydminster Conventional	**38**	38	32	**130**	118
Corporate	**—**	1	1	**1**	1
Capital expenditures - continuing operations	**239**	278	231	**766**	755
Capital expenditures - discontinued operations	**—**	—	—	**—**	250
Capital expenditures[1]	**239**	278	231	**766**	1,005

(1) Comparative periods have been revised to exclude land expenditures from capital expenditures.

For the three months ended September 30, 2026, drilling, completion and equipping activities accounted for 41% of capital expenditures as the Company drilled 61 new wells; 16 in Cold Lake, 25 in Lloydminster Thermal and 20 in Lloydminster Conventional. For the nine months ended September 30, 2026, drilling, completion and equipping activities accounted for 42% of capital expenditures as the Company drilled 184 new wells during the period; 41 in Cold Lake, 68 in Lloydminster Thermal and 75 in Lloydminster Conventional.

For the three and nine months ended September 30, 2026, facilities and pipeline expenditures accounted for 49% and 46% of capital expenditures, respectively, and related primarily to the construction of the Meota Central processing facility, increased spending on pads and above ground flow line facilities at Meota East, and the Plover Lake central processing facility expansion.

DECOMMISSIONING EXPENDITURES

The following table summarizes the Company's decommissioning expenditures by province.

	Three Months Ended			Nine Months Ended	
($ millions, unless otherwise indicated)	**September 30, 2026**	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Alberta	**4**	2	4	**12**	15
British Columbia	**4**	4	1	**19**	18
Saskatchewan	**1**	2	4	**6**	2
Total decommissioning expenditures[(1)]	**9**	8	9	**37**	35

(1) Decommissioning expenditures includes continuing and discontinued operations.

ACQUISITIONS

Vawn Acquisition

In connection with the Vawn Acquisition completed in 2025, contingent consideration of $1 million is payable for each dollar per barrel that the WCS benchmark crude oil price averages above C$70.00 per barrel in a specified three-month period, payable quarterly over the 14-quarter period following the close of the transaction, up to a maximum of $75 million. During the nine months ended September 30, 2026, a $42 million increase in the fair value of the obligation was recorded as an unrealized loss in the Condensed Consolidated Interim Statements of Income and Comprehensive Income, based on the discounted present value of expected future payments using forecast WCS pricing and a 10% discount rate, resulting in a total estimated amount owing under the agreement of $75 million. During the nine months ended September 30, 2026, $66 million of this liability was settled.

RISK MANAGEMENT

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

Credit Risk

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

Upon 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 comprised 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 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 exposed to price fluctuations. Furthermore, the Company may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, the Company may forego the benefits that would otherwise be experienced if commodity prices increase.

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

Term	Contract	Index	Currency	Volume	Units	Price
Jan 1, 2026 - Dec 31, 2026	Swap	WCS	USD	50,000	bbl/d	$(12.00)

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

Term	Contract	Index	Currency	Volume	Units	Price
Jan 1, 2026 - Dec 31, 2026	Swap	AECO	CAD	100,000	GJ/d	$2.00
Jan 1, 2027 - Dec 31, 2028	Swap	AECO	CAD	110,000	GJ/d	$3.10
Jan 1, 2029 - Dec 31, 2029	Swap	AECO	CAD	130,000	GJ/d	$2.49

Foreign Exchange Risk

The Company is exposed to fluctuations of the CAD to USD exchange rate given commodity pricing is directly influenced by U.S. dollar denominated benchmark pricing. In addition, the Company periodically borrows from its Credit Facilities in U.S. dollars (see the "*Capital Resources*" section of this MD&A). The Company actively manages foreign exchange risk using foreign exchange derivatives.

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

Term[(1)]	Contract	USD per Month	CAD/USD Floor	CAD/USD Ceiling
Mar 31, 2027 - Aug 31, 2028	Collar	100 million	1.3500	1.4500

(1) On the date that is three months prior to the start date for each month in the term, the Company is entered into the above collar if CAD/USD fixes at or above 1.3775. The collars have a European expiry date (i.e. exercise is based on CAD/USD on the last business day of the month).

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

Interest Rate Risk

The Company is exposed to movements in floating interest rates on the Credit Facilities.

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

Notional (C$)	Term	Contract	Index	Contract Price
1,500 million	Dec 1, 2025 - Feb 1, 2027	Floor	CORRA	2.25%
1,500 million	Feb 1, 2027 - Apr 1, 2027	Floor	CORRA	2.50%
1,500 million	Apr 1, 2027 - May 1, 2028	Floor	CORRA	2.75%
1,500 million	May 1, 2028 - Dec 1, 2031	Swaption[(1)]	CORRA	3.18%

(1) The swap counterparties have the option to enter into a CORRA swap on April 28, 2028.

For a listing of the Company's commodity contracts, foreign exchange and interest rate contracts outstanding as at September 30, 2026, refer to Note 11 in the interim financial statements.

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, 2026**	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
(Gain) loss on risk management contracts - realized	**(7)**	20	(12)	**(35)**	25
(Gain) loss on risk management contracts - unrealized	**(27)**	7	(40)	**20**	60
Total (gain) loss on risk management contracts	**(34)**	27	(52)	**(15)**	85
Realized (gain) loss on risk management contracts per boe[(1)]	**(0.61)**	1.86	(1.09)	**(1.07)**	0.81

(1) Calculated using sales volumes for both continuing and discontinued operations.

Strathcona realized a gain on risk management contracts of $7 million for the three months ended September 30, 2026, compared to a loss of $20 million for the same period in 2025 and a gain of $12 million for the three months ended June 30, 2026. The Company realized a gain on risk management contracts of $35 million for the nine months ended September 30, 2026, compared to a loss of $25 million for the same period in 2025. The realized gains and losses are attributable to differences between contracted hedge prices and realized commodity benchmark prices.

As at September 30, 2026, the mark-to-market value of risk management contracts was a net liability of $46 million (December 31, 2025 - net liability of $26 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 11 of the interim financial statements.

SEGMENT RESULTS

The Chief Operating Decision Makers ("**CODMs**") of the Company are comprised of the Chief Financial Officer, Chief Operating Officer and Chief Commercial Officer.

The CODMs assess performance based on the distinct attributes of its oil production operations. Each segment encompasses a group of assets with a unique combination of geographic focus, hydrocarbon resource type and extraction method, resulting in its own discrete economic profile. Segment profit is measured using Operating Earnings, which is the profit measure regularly reviewed by the CODMs for the purposes of performance assessment and resource allocation. The Company operates through three business segments:

- Cold Lake, which includes the development and production of bitumen in the Cold Lake region of Northern Alberta;
- Lloydminster Thermal, which includes the development and production of heavy oil through thermal steam-assisted gravity drainage methods in Southwest Saskatchewan; and
- Lloydminster Conventional, which includes the development and production of heavy oil through both conventional and enhanced oil recovery initiatives primarily in Southeast Alberta and Southwest Saskatchewan.

Activities not directly attributable to an operating segment are reported under Corporate and Midstream.

Strathcona's midstream operations is comprised of the wholly-owned Hardisty Rail Terminal ("**HRT**"), acquired in April 2025, which has throughput of approximately 40,000 barrels per day, the majority of which is committed under take-or-pay arrangements.

For the Three Months Ended ($ millions, unless otherwise indicated)	Cold Lake Segment			Lloydminster Thermal Segment			Lloydminster Conventional Segment			Corporate and Midstream			Consolidated		
	Sep 30, 2026	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026
Production volumes															
Bitumen (bbl/d)	**64,776**	61,157	62,782	**—**	—	—	**—**	—	—	**—**	—	—	**64,776**	61,157	62,782
Heavy oil (bbl/d)	**—**	—	—	**38,547**	31,937	33,571	**19,747**	22,006	20,182	**—**	—	—	**58,294**	53,943	53,753
Condensate and light oil (bbl/d)	**—**	—	—	**—**	—	—	**61**	39	69	**—**	—	—	**61**	39	69
Other NGLs (bbl/d)	**—**	—	—	**—**	—	—	**17**	4	12	**—**	—	—	**17**	4	12
Natural gas (mcf/d)	**—**	—	—	**—**	—	—	**2,030**	2,642	2,436	**—**	—	—	**2,030**	2,642	2,436
Production volumes (boe/d)	**64,776**	61,157	62,782	**38,547**	31,937	33,571	**20,163**	22,489	20,669	**—**	—	—	**123,486**	115,584	117,022
Sales volumes (boe/d)	**64,917**	61,433	62,390	**39,053**	30,941	33,164	**20,046**	22,861	20,576	**—**	—	—	**124,016**	115,235	116,130
Segment revenues															
Oil and natural gas sales	**829**	586	875	**426**	247	388	**204**	176	223	**—**	—	—	**1,459**	1,009	1,486
Sale of purchased products	**—**	6	—	**—**	—	8	**8**	9	6	**13**	16	68	**21**	31	82
Blending costs	**(269)**	(194)	(338)	**(37)**	(3)	(43)	**(26)**	(25)	(36)	**—**	—	—	**(332)**	(222)	(417)
Purchased product	**—**	(6)	—	**—**	—	(7)	**(8)**	(9)	(5)	**(13)**	(16)	(68)	**(21)**	(31)	(80)
Midstream revenue	**—**	—	—	**—**	—	—	**—**	—	—	**7**	9	9	**7**	9	9
Oil and natural gas sales, net of blending - continuing[1]	**560**	392	537	**389**	244	346	**178**	151	188	**7**	9	9	**1,134**	796	1,080
Segment expenses															
Royalties	**194**	86	173	**40**	22	32	**28**	20	27	**—**	—	—	**262**	128	232
Production and operating – Energy	**30**	19	24	**29**	13	30	**8**	6	8	**—**	—	—	**67**	38	62
Production and operating – Non-energy	**54**	48	45	**31**	22	29	**30**	32	30	**6**	5	5	**121**	107	109
Transportation	**23**	21	23	**74**	63	64	**7**	8	9	**—**	—	—	**104**	92	96
Field Operating Income - Continuing[1]	**259**	218	272	**215**	124	191	**105**	85	114	**1**	4	4	**580**	431	581
Depletion, depreciation and amortization	**44**	43	44	**68**	65	58	**35**	41	35	**3**	2	3	**150**	151	140
General and administrative	**8**	9	9	**8**	8	9	**7**	7	8	**—**	—	—	**23**	24	26
Finance costs	**—**	1	1	**—**	1	1	**—**	—	—	**9**	12	8	**9**	14	10
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(1)**	(8)	—	**(1)**	(8)	—
Interest	**—**	—	—	**—**	—	—	**—**	—	—	**28**	23	29	**28**	23	29
Operating Earnings - Continuing	**207**	165	218	**139**	50	123	**63**	37	71	**(38)**	(25)	(36)	**371**	227	376
(Gain) loss on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(7)**	20	(12)	**(7)**	20	(12)
(Gain) loss on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(27)**	7	(40)	**(27)**	7	(40)
Foreign exchange loss (gain) - realized	**—**	—	—	**—**	—	—	**—**	—	—	**3**	(2)	—	**3**	(2)	—
Foreign exchange (gain) loss - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(1)**	19	(2)	**(1)**	19	(2)
Transaction related costs	**—**	—	—	**—**	—	—	**—**	—	—	**2**	4	1	**2**	4	1
Gain on marketable securities - realized	**—**	—	—	**—**	—	—	**—**	—	—	**—**	(22)	—	**—**	(22)	—
Change in decommissioning liabilities	**—**	—	—	**—**	—	—	**—**	—	—	**6**	—	1	**6**	—	1
Deferred tax expense	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—	**97**	57	95
Income and comprehensive income from continuing operations													**298**	144	333
Income and comprehensive income from discontinued operations, net of tax													**—**	429	—
Income and comprehensive income													**298**	573	333

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

For the Three Months Ended ($/boe)	Cold Lake Segment			Lloydminster Thermal Segment			Lloydminster Conventional Segment			Corporate and Midstream			Consolidated		
	Sep 30, 2026	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026	**Sep 30, 2026**	Sep 30, 2025	Jun 30, 2026
Segment revenues															
Oil and natural gas sales	**100.22**	75.05	107.28	**109.26**	85.92	116.55	**100.21**	74.00	106.97	**—**	—	—	**102.70**	77.48	109.51
Sale of purchased products	**—**	0.96	—	**—**	—	2.55	**4.65**	4.23	3.00	**1.14**	1.56	6.47	**1.89**	2.37	7.73
Blending costs	**(6.62)**	(5.72)	(12.67)	**(0.65)**	(0.05)	(2.39)	**(3.90)**	(2.60)	(6.55)	**—**	—	—	**(3.93)**	(3.27)	(8.27)
Purchased product	**—**	(0.97)	—	**—**	—	(2.04)	**(4.66)**	(4.26)	(2.81)	**(1.12)**	(1.60)	(6.47)	**(1.88)**	(2.41)	(7.55)
Midstream revenue	**—**	—	—	**—**	—	—	**—**	—	—	**0.67**	0.91	0.82	**0.67**	0.91	0.82
Oil and natural gas sales, net of blending - continuing[1]	**93.60**	69.32	94.61	**108.61**	85.87	114.67	**96.30**	71.37	100.61	**0.69**	0.87	0.82	**99.45**	75.08	102.24
Segment expenses															
Royalties	**32.55**	15.25	30.38	**10.95**	7.55	10.82	**15.35**	9.43	14.16	**—**	—	—	**22.97**	12.03	21.92
Production and operating – Energy	**4.93**	3.34	4.39	**8.06**	4.54	10.13	**4.01**	3.26	4.29	**0.01**	—	0.01	**5.77**	3.65	6.03
Production and operating – Non-energy	**9.19**	8.67	7.97	**8.66**	7.78	9.41	**15.95**	14.89	15.97	**0.44**	0.43	0.52	**10.56**	10.09	10.32
Transportation	**3.82**	3.75	4.00	**20.75**	22.38	21.05	**3.70**	3.24	5.20	**—**	0.02	—	**9.13**	8.67	9.08
Field Operating Netback - Continuing[1]	**43.11**	38.31	47.87	**60.19**	43.62	63.26	**57.29**	40.55	60.99	**0.24**	0.42	0.29	**51.02**	40.64	54.89
Depletion, depreciation and amortization	**7.57**	7.55	7.73	**18.87**	22.78	19.29	**18.84**	19.63	18.67	**0.26**	0.23	0.25	**13.21**	14.27	13.22
General and administrative	**1.39**	1.53	1.55	**2.22**	2.83	2.83	**3.67**	2.67	4.35	**0.01**	—	0.02	**2.03**	2.23	2.43
Finance costs	**0.12**	0.15	0.12	**0.09**	0.24	0.11	**0.01**	0.02	0.01	**0.73**	1.12	0.76	**0.82**	1.27	0.86
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(0.02)**	(0.76)	(0.03)	**(0.02)**	(0.76)	(0.03)
Interest	**—**	—	—	**—**	—	—	**—**	—	—	**2.48**	2.18	2.75	**2.48**	2.18	2.75
Operating Earnings - Continuing	**34.03**	29.08	38.47	**39.01**	17.77	41.03	**34.77**	18.23	37.96	**(3.22)**	(2.35)	(3.46)	**32.50**	21.45	35.66
Effective royalty rate (%)[1]	**34.8**	22.0	32.1	**10.1**	8.8	9.4	**15.9**	13.2	14.1	**—**	—	—	**23.1**	16.0	21.4

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

For the Nine Months Ended ($ millions, unless otherwise indicated)	Cold Lake Segment		Lloydminster Thermal Segment		Lloydminster Conventional Segment		Corporate and Midstream		Consolidated	
	September 30, 2026	September 30, 2025	**September 30, 2026**	September 30, 2025	**September 30, 2026**	September 30, 2025	**September 30, 2026**	September 30, 2025	**September 30, 2026**	September 30, 2025
Production volumes										
Bitumen (bbl/d)	**62,990**	60,919	**—**	—	**—**	—	**—**	—	**62,990**	60,919
Heavy oil (bbl/d)	**—**	—	**35,586**	29,216	**20,008**	22,767	**—**	—	**55,594**	51,983
Condensate and light oil (bbl/d)	**—**	—	**—**	—	**69**	60	**—**	—	**69**	60
Other NGLs (bbl/d)	**—**	—	**—**	—	**15**	17	**—**	—	**15**	17
Natural gas (mcf/d)	**—**	—	**—**	—	**2,244**	2,853	**—**	—	**2,244**	2,853
Production volumes (boe/d)	**62,990**	60,919	**35,586**	29,216	**20,466**	23,320	**—**	—	**119,042**	113,455
Sales volumes (boe/d)	**63,057**	60,878	**35,967**	29,887	**20,431**	23,468	**—**	—	**119,455**	114,233
Segment revenues										
Oil and natural gas sales	**2,351**	1,856	**1,118**	739	**597**	564	**—**	—	**4,066**	3,159
Sale of purchased product	**2**	8	**8**	—	**14**	19	**83**	26	**107**	53
Blending costs	**(858)**	(683)	**(112)**	(18)	**(85)**	(97)	**—**	—	**(1,055)**	(798)
Purchased product	**(2)**	(8)	**(6)**	—	**(14)**	(19)	**(83)**	(26)	**(105)**	(53)
Midstream revenue	**—**	—	**—**	—	**—**	—	**25**	16	**25**	16
Oil and natural gas sales, net of blending - continuing[1]	**1,493**	1,173	**1,008**	721	**512**	467	**25**	16	**3,038**	2,377
Segment expenses										
Royalties	**468**	218	**93**	55	**75**	63	**—**	—	**636**	336
Production and operating – Energy	**89**	85	**92**	62	**25**	24	**—**	—	**206**	171
Production and operating – Non-energy	**143**	155	**90**	74	**89**	99	**16**	10	**338**	338
Transportation	**69**	64	**201**	187	**24**	23	**—**	—	**294**	274
Field Operating Income - Continuing[1]	**724**	651	**532**	343	**299**	258	**9**	6	**1,564**	1,258
Depletion, depreciation and amortization	**132**	123	**188**	188	**104**	133	**8**	10	**432**	454
General and administrative	**27**	24	**27**	21	**23**	19	**—**	—	**77**	64
Finance costs	**2**	3	**1**	2	**—**	—	**27**	36	**30**	41
Other income	**—**	—	**—**	—	**—**	—	**(1)**	(14)	**(1)**	(14)
Interest	**—**	—	**—**	—	**—**	—	**85**	107	**85**	107
Operating Earnings - Continuing	**563**	501	**316**	132	**172**	106	**(110)**	(133)	**941**	606
(Gain) loss on risk management contracts - realized	**—**	—	**—**	—	**—**	—	**(35)**	25	**(35)**	25
Loss on risk management contracts - unrealized	**—**	—	**—**	—	**—**	—	**20**	60	**20**	60
Foreign exchange loss - realized	**—**	—	**—**	—	**—**	—	**2**	2	**2**	2
Foreign exchange loss (gain) - unrealized	**—**	—	**—**	—	**—**	—	**2**	(25)	**2**	(25)
Transaction related costs	**—**	—	**—**	—	**—**	—	**3**	19	**3**	19
Gain on marketable securities - realized	**—**	—	**—**	—	**—**	—	**—**	(69)	**—**	(69)
Change in decommissioning liabilities	**—**	—	**—**	—	**—**	—	**20**	—	**20**	—
Loss on contingent consideration	**—**	—	**—**	—	**—**	—	**42**	—	**42**	—
Deferred tax expense	**—**	—	**—**	—	**—**	—	**—**	—	**217**	138
Income and comprehensive income from continuing operations									**670**	456
Income and comprehensive income from discontinued operations, net of tax									**—**	554
Income and comprehensive income									**670**	**1,010**

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

For the Nine Months Ended ($/boe)	Cold Lake Segment		Lloydminster Thermal Segment		Lloydminster Conventional Segment		Corporate and Midstream		Consolidated	
	September 30, 2026	September 30, 2025	**September 30, 2026**	September 30, 2025	**September 30, 2026**	September 30, 2025	**September 30, 2026**	September 30, 2025	**September 30, 2026**	September 30, 2025
Segment revenues										
Oil and natural gas sales	**95.71**	77.77	**103.83**	88.56	**95.52**	77.69	**—**	0.01	**97.79**	80.05
Sale of purchased products	**0.12**	0.47	**0.78**	—	**2.55**	2.92	**2.55**	0.83	**3.28**	1.69
Blending costs	**(9.02)**	(7.20)	**(1.27)**	(0.16)	**(3.74)**	(4.82)	**—**	—	**(5.45)**	(4.32)
Purchased product	**(0.12)**	(0.49)	**(0.63)**	—	**(2.48)**	(2.94)	**(2.54)**	(0.85)	**(3.22)**	(1.71)
Midstream revenue	**—**	—	**—**	—	**—**		**0.78**	0.52	**0.78**	0.52
Oil and natural gas sales, net of blending - continuing[1]	**86.69**	70.55	**102.71**	88.40	**91.85**	72.85	**0.79**	0.51	**93.18**	76.23
Segment expenses										
Royalties	**27.21**	13.08	**9.44**	6.70	**13.40**	9.98	**—**	—	**19.50**	10.77
Production and operating – Energy	**5.17**	5.09	**9.38**	7.56	**4.36**	3.75	**0.01**	0.01	**6.32**	5.47
Production and operating – Non-energy	**8.34**	9.37	**9.14**	9.09	**15.90**	15.42	**0.48**	0.32	**10.36**	10.85
Transportation	**4.00**	3.86	**20.46**	22.95	**4.33**	3.51	**—**	0.01	**9.02**	8.79
Field Operating Netback - Continuing[1]	**41.97**	39.15	**54.29**	42.10	**53.86**	40.19	**0.30**	0.17	**47.98**	40.35
Depletion, depreciation and amortization	**7.71**	7.43	**19.16**	22.98	**18.61**	20.82	**0.24**	0.32	**13.26**	14.57
General and administrative	**1.59**	1.41	**2.70**	2.63	**4.09**	2.74	**0.01**	—	**2.36**	2.05
Finance costs	**0.12**	0.14	**0.11**	0.29	**0.01**	0.02	**0.82**	1.15	**0.92**	1.30
Other income	**—**	—	**—**	—	**—**	—	**(0.02)**	(0.46)	**(0.02)**	(0.46)
Interest	**—**	—	**—**	—	**—**	—	**2.61**	3.44	**2.61**	3.44
Operating Earnings - Continuing	**32.55**	30.17	**32.32**	16.20	**31.15**	16.61	**(3.36)**	(4.28)	**28.85**	19.45
Effective royalty rate (%)[1]	**31.4**	18.5	**9.2**	7.6	**14.6**	13.7	**—**	—	**20.9**	14.1

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

Cold Lake Segment

Production at the Cold Lake segment for the three months ended September 30, 2026 increased to 64,776 boe per day compared to 61,157 boe per day in the same period of 2025. This increase was primarily due to production gains at Lindbergh and Orion, and underperformance due to high water cuts and low reservoir pressure at Lindbergh in the comparable period, partially offset by production gains at Tucker in the comparable period. For the nine months ended September 30, 2026, production increased to 62,990 boe per day, compared to 60,919 boe per day in the same period of 2025. This increase was primarily due to production gains at Orion, partially offset by a planned steam plant outage at Tucker.

Oil and natural gas sales, net of blending, increased to $560 million ($93.60 per boe) during the three months ended September 30, 2026 compared to $392 million ($69.32 per boe) for the same period of 2025. During the nine months ended September 30, 2026, oil and natural gas sales, net of blending, increased to $1,493 million ($86.69 per boe) compared to $1,173 million ($70.55 per boe) for the same period of 2025. These increases were primarily due to higher WCS Hardisty benchmark pricing and an increase in sales volumes, partially offset by increased blending costs due to higher condensate benchmark pricing.

The effective royalty rate for the three and nine months ended September 30, 2026 increased to 34.8% and 31.4%, respectively, from 22.0% and 18.5%, in the same periods of 2025. These increases were primarily the result of higher commodity benchmark pricing.

Energy related production and operating expenses for the three months ended September 30, 2026 increased to $30 million ($4.93 per boe) from $19 million ($3.34 per boe) in the same period in 2025. During the nine months ended September 30, 2026 energy related production and operating expenses increased to $89 million ($5.17 per boe) from $85 million ($5.09 per boe) in the same period of 2025. These increases were primarily attributable to higher fuel costs due to an increase in natural gas benchmark prices and an increase in carbon tax expense as the result of higher compliance obligations.

Non-energy related production and operating expenses for the three months ended September 30, 2026 increased to $54 million ($9.19 per boe) from $48 million ($8.67 per boe) in the same period in 2025. This increase was primarily due to increased surface maintenance costs, road maintenance and inventory purchases, partially offset by a decrease in downhole maintenance. During the nine months ended September 30, 2026, non-energy related production and operating expenses decreased to $143 million ($8.34 per boe) from $155 million ($9.37 per boe) for the same period of 2025. This decrease was primarily attributable to lower chemical and surface maintenance costs, partially offset by an increase in property taxes.

For the three months ended September 30, 2026, transportation expenses increased to $23 million ($3.82 per boe) compared to $21 million ($3.75 per boe) in the same period of 2025. This increase was primarily attributable to higher sales volumes at Lindbergh and the timing and utilization of make-up rights. For the nine months ended September 30, 2026, transportation expenses increased to $69 million ($4.00 per boe) from $64 million ($3.86 per boe), in the same period of 2025. This increase was primarily attributable to the timing and utilization of make-up rights.

Depletion, depreciation and amortization for the three and nine months ended September 30, 2026 increased to $44 million ($7.57 per boe) and $132 million ($7.71 per boe), respectively, compared to $43 million ($7.55 per boe) and $123 million ($7.43 per boe) in the same periods of 2025. These increases were primarily due to higher sales volumes.

General and administrative for the three months ended September 30, 2026 decreased to $8 million ($1.39 per boe) compared to $9 million ($1.53 per boe) in the same period of 2025. General and administrative for the nine months ended September 30, 2026 increased to $27 million ($1.59 per boe) compared to $24 million ($1.41 per boe) in the same period of 2025. This increase was primarily due to a higher annual Company bonus payment made in the first quarter of 2026 compared to the prior year and the reallocation of corporate costs across the business following the sale of the Montney segment.

Lloydminster Thermal Segment

Production at the Lloydminster Thermal segment for the three months ended September 30, 2026 increased to 38,547 boe per day compared to 31,937 boe per day in the same period of 2025. For the nine months ended September 30, 2026, production increased to 35,586 boe per day, compared to 29,216 boe per day in the same period of 2025. These increases were primarily due to the Vawn Acquisition and the start-up of the new Meota Central facility at the end of July.

Oil and natural gas sales, net of blending, increased to $389 million ($108.61 per boe) during the three months ended September 30, 2026 compared to $244 million ($85.87 per boe) for the same period of 2025. For the nine months ended September 30, 2026, oil and natural gas sales, net of blending, increased to $1,008 million ($102.71 per boe) compared to $721 million ($88.40 per boe) for the same period of 2025. These increases were primarily attributable to higher WCS USGC benchmark prices and an increase in sales volumes, partially offset by increased blending costs at Vawn due to higher condensate benchmark pricing.

The effective royalty rate for the three and nine months ended September 30, 2026 increased to 10.1% and 9.2%, respectively, compared to 8.8% and 7.6% in the same periods of 2025. These increases were the result of higher commodity benchmark pricing.

Energy related production and operating expenses for the three months ended September 30, 2026 increased to $29 million ($8.06 per boe) compared to $13 million ($4.54 per boe) for the same period in 2025. Energy related production and operating expenses for the nine months ended September 30, 2026 increased to $92 million ($9.38 per boe) compared to $62 million ($7.56 per boe) for the same period in 2025. These increases were primarily due to increases in operating costs associated with the Vawn Acquisition of $5 million and $19 million, for the three and nine month periods ended September 30, 2026, higher fuel costs due to an increase in natural gas benchmark prices and the start-up of the new Meota Central facility at the end of July, and an increase in carbon tax expense as the result of higher compliance obligations.

Non-energy related production and operating expenses for the three months ended September 30, 2026 increased to $31 million ($8.66 per boe) compared to $22 million ($7.78 per boe) in the same period of 2025. This increase was primarily due to $5 million in operating costs associated with the Vawn Acqusition, an increase in surface maintenance costs due to increased activity and the addition of the Meota Central facility, and an increase in property taxes due to higher mill rates. Non-energy related production and operating expenses for the nine months ended September 30, 2026 increased to $90 million ($9.14 per boe), compared to $74 million ($9.09 per boe) for the same period in 2025. This increase was primarily due to $16 million in operating costs associated with the Vawn Acquisition and higher downhole and surface maintenance expenses.

For the three months ended September 30, 2026, transportation expenses increased to $74 million ($20.75 per boe) compared to $63 million ($22.38 per boe) in the same period of 2025. This increase was due to increased sales volumes, primarily as a result of the Vawn Acquisition which contributed $2 million of transportation costs in the current quarter, and higher rail transportation costs resulting from increased fuel charges. For the nine months ended September 30, 2026, transportation expenses increased to $201 million ($20.46 per boe) from $187 million ($22.95 per boe) in the same period of 2025. This increase was due to increased sales volumes, primarily as a result of the Vawn Acquisition which contributed $6 million of transportation costs in the current year, and higher rail transportation costs resulting from increased fuel charges. Despite the increases in absolute costs, the decreases on a per boe basis for the three and nine months ended September 30, 2026 reflects that the majority of the incremental costs relate to Vawn volumes, which are transported by pipeline and incur lower per barrel transportation costs.

Depletion, depreciation and amortization for the three months ended September 30, 2026 increased to $68 million ($18.87 per boe) compared to $65 million ($22.78 per boe) in the same period of 2025. This increase was primarily due to higher sales volumes. Depletion, depreciation and amortization for the nine months ended September 30, 2026 remained consistent at $188 million ($19.16 per boe) compared to $188 million ($22.98 per boe), in the same period of 2025. These decreases, on a per boe basis, were primarily due to the addition of Vawn, which carries a lower depletion rate per barrel.

General and administrative for the three months ended September 30, 2026 remained consistent at $8 million ($2.22 per boe) compared to $8 million ($2.83 per boe) in the same period of 2025. General and administrative for the nine months ended September 30, 2026 increased to $27 million ($2.70 per boe) compared to $21 million ($2.63 per boe) in the same period of 2025. This increases was primarily due to a higher annual Company bonus payment made in the first quarter of 2026 compared to the prior year and the reallocation of corporate costs across the business following the sale of the Montney segment.

Lloydminster Conventional Segment

Production at the Lloydminster Conventional segment for the three months ended September 30, 2026, decreased to 20,163 boe per day compared to 22,489 boe per day in the same period of 2025. For the nine months ended September 30, 2026, production decreased to 20,466 boe per day, compared to 23,320 boe per day in the same period of 2025. These decreases were primarily attributable to development challenges and weather and equipment related issues.

Oil and natural gas sales, net of blending, increased to $178 million ($96.30 per boe) during the three months ended September 30, 2026 compared to $151 million ($71.37 per boe) for the same period of 2025. Oil and natural gas sales, net of blending, increased to $512 million ($91.85 per boe) during the nine months ended September 30, 2026 compared to $467 million ($72.85 per boe) for the same period of 2025. These increases were primarily attributable to higher WCS Hardisty benchmark pricing, partially offset by increased blending costs due to higher condensate benchmark pricing and a decrease in sales volumes.

The effective royalty rate for the three and nine months ended September 30, 2026 increased to 15.9% and 14.6%, respectively, compared to 13.2% and 13.7%, in the same periods of 2025. These increases were the result of higher commodity benchmark pricing.

Energy related production and operating expenses for the three months ended September 30, 2026 increased to $8 million ($4.01 per boe) compared to $6 million ($3.26 per boe) for the same period in 2025. This increase was primarily due to a slight increase in electricity and carbon tax expenses. During the nine months ended September 30, 2026 energy related production and operating expenses remained consistent at $25 million ($4.36 per boe) from $24 million ($3.75 per boe) for the same period in 2025. Despite absolute costs remaining consistent, the increase on a per boe basis reflects the decrease in sales volumes.

Non-energy related production and operating expenses for the three months ended September 30, 2026 decreased to $30 million ($15.95 per boe) compared to $32 million ($14.89 per boe) in the same period of 2025. Non-energy related production and operating expenses for the nine months ended September 30, 2026 decreased to $89 million ($15.90 per boe) compared to $99 million ($15.42 per boe) for the same period in 2025. These decreases were primarily attributable to lower surface and downhole maintenance costs, and lower chemical costs as the result of improved H2S scavenger pricing. Despite the decreases in absolute costs, the increase on a per boe basis reflects the decrease in sales volumes.

For the three months ended September 30, 2026, transportation expenses decreased to $7 million ($3.70 per boe) compared to $8 million ($3.24 per boe) in the same period of 2025. Despite the decrease on an absolute basis, the increase on a per boe basis reflects the decrease in sales volumes. For the nine months ended September 30, 2026, transportation expenses increased to $24 million ($4.33 per boe) from $23 million ($3.51 per boe) in the same period of 2025. Transportation expenses increased primarily due to certain volumes from Winter being temporarily transported by rail during the second quarter of 2026, which incur higher per barrel transportation costs.

Depletion, depreciation and amortization for the three and nine months ended September 30, 2026 decreased to $35 million ($18.84 per boe) and $104 million ($18.61 per boe), respectively, compared to $41 million ($19.63 per boe) and $133 million ($20.82 per boe), in the same periods of 2025. These decreases were primarily due to an impairment loss of $376 million recorded at year end 2025, which lowered the depletable base for certain fields.

General and administrative for the three months ended September 30, 2026 remained consistent at $7 million ($3.67 per boe) compared to $7 million ($2.67 per boe) in the same period of 2025. General and administrative for the nine months ended September 30, 2026 increased to $23 million ($4.09 per boe) compared to $19 million ($2.74 per boe) in the same period of 2025. This increase was primarily due to a higher annual Company bonus payment made in the first quarter of 2026 compared to the prior year and the reallocation of corporate costs across the business following the sale of the Montney segment.

Midstream

Midstream revenue for the three and nine months ended September 30, 2026 was $7 million ($0.67 per boe) and $25 million ($0.78 per boe), respectively, compared to $9 million ($0.91 per boe) and $16 million ($0.52 per boe) in the same periods of 2025. Non-energy related production and operating expenses associated with midstream operations, for the three and nine months ended September 30, 2026, were $6 million ($0.44 per boe) and $16 million ($0.48 per boe), respectively, compared to $5 million ($0.43 per boe) and $10 million ($0.32 per boe) in the same periods of 2025.

CAPITAL RESOURCES

Bank Credit Facilities

Covenant-Based Revolving Credit Facility and Term Credit Facility

At September 30, 2026, the Company had a covenant-based revolving credit facility (the "**Revolving Credit Facility**") with total capacity of $3.51 billion (December 31, 2025 – $3.24 billion) and a US$175 million covenant-based term facility (December 31, 2025 - US$175 million) (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**") with a syndicate of Canadian, U.S. and international financial institutions. The agreement governing the Credit Facilities (the "**Credit Agreement**") includes an accordion feature which permits the Company to increase the available Credit Facilities by up to an additional $750 million, subject to the satisfaction of certain conditions.

At September 30, 2026, the Credit Facilities have a maturity date of December 31, 2030. There are no mandatory payments on either the Revolving Credit Facility or the Term Credit Facility. Borrowings under the Revolving Credit Facility may be drawn and repaid from time to time by the Company in Canadian or U.S. dollars. Borrowings under the Term Credit Facility were made in a single upfront draw in U.S. dollars and amounts repaid by the Company may not be re-borrowed. The Credit Facilities are not subject to annual or semi-annual reviews.

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

At September 30, 2026, the Company had letters of credit outstanding under the Revolving Credit Facility of $3 million (December 31, 2025 - $2 million).

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

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

Foreign currency risk associated with these borrowings is offset at the time of borrowing as cross-currency interest rate swap contracts fix the principal and interest payments due at maturity. Debt on the balance sheet includes the Canadian dollar equivalent of U.S. borrowings translated at the period end exchange rate, which does not include the offsetting impact of cross-currency interest rate swaps. As at September 30, 2026 the cross-currency swap asset was $25 million (December 31, 2025 – a liability of $5 million) and total debt includes an unrealized loss of $25 million (December 31, 2025 – unrealized gain of $5 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 interest swap contracts are included in foreign exchange gains or losses in the interim financial statements.

As at September 30, 2026, the Company had the following cross-currency interest rate swap contracts outstanding:

Notional (US$)	Maturity Date	Contract Price
1,060 million	October 23, 2026	CAD/USD 1.4019
175 million	October 28, 2026	CAD/USD 1.4095

Financial Covenants

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

(i) Total Debt to Adjusted EBITDA Ratio – All debt, excluding capital leases and letters of credit constituting debt ("**Total Debt**"), each as defined in the Credit Agreement shall not exceed 4.0 times trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period ("**Adjusted EBITDA**"). For the

purposes of Adjusted EBITDA, lease payments are deducted from the calculation if a lease would have been considered an operating lease before the adoption of IFRS 16.

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

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

As at September 30, 2026, the Company was in compliance with such financial covenants.

Demand Letter of Credit Facility

As at September 30, 2026, the Company had a $250 million (December 31, 2025 - $200 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 ("**EDC**") in favor of the financial institution. The Company and its subsidiaries have indemnified EDC for the amount of any payment made by EDC to the financial institution pursuant to such account performance security guarantee; however, the obligations under such indemnity are unsecured. The letters of credit outstanding under the LC Facility do not impact the Company's borrowing capacity under the Revolving Credit Facility. As at September 30, 2026, the Company had letters of credit in the amount of $53 million (December 31, 2025 - $57 million) outstanding under the LC Facility.

CAPITAL MANAGEMENT AND LIQUIDITY

The Company's policy is to maintain a strong capital base with the objectives of preserving financial flexibility, upholding creditor and market confidence, and sustaining the business's future development. 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, debt and working capital.

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

The availability under the Credit Facilities are summarized in the following table.

As at	**September 30, 2026**	December 31, 2025
Revolving Credit Facility capacity	**3,505**	3,240
Term Credit Facility capacity[(1)]	**249**	240
Credit Facilities capacity	**3,754**	3,480
Credit Facilities debt[(1)]	**(1,757)**	(2,116)
Unrealized loss (gain) on U.S. borrowings	**25**	(5)
Letters of credit outstanding	**(3)**	(2)
Availability	**2,019**	1,357

(1) CAD equivalent converted at the period end exchange rate.

The Company has a working capital deficiency as part of its current capital structure. As at September 30, 2026, the working capital deficiency was $481 million (December 31, 2025 - deficiency of $396 million). Management believes that its current capital resources and its ability to manage cash flow and working capital levels will allow the Company to remedy its working capital deficiency, meet its current and future obligations, make scheduled interest payments, fund planned capital expenditures and fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future or additional sources of capital will not be necessary. The Company's cash flow and the development of projects are subject to certain risk factors discussed in the "*Risk Factors*" section of the Company's annual information form for the year ended December 31, 2025.

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

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

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, 2026.

	Total	<1 year	1-3 years	4-5 years	> 5 years
Credit Facilities[1]	**1,732**	—	—	1,732	—
Accounts payable and accrued liabilities	**835**	835	—	—	—
Risk management contract liability	**99**	42	57	—	—
Lease obligations[2]	**96**	26	29	18	23
Contingent consideration	**9**	9	—	—	—
Total	**2,771**	912	86	1,750	23

(1) Contractual amount reflects contracted settlement price on cross currency interest rate swap contracts and excludes future interest payments on borrowings.
(2) Amounts relate to undiscounted payments for lease obligations.

As at September 30, 2026, the Company was committed to the following non-cancellable payments.

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Transportation and processing	**2,585**	171	364	362	1,688
Capital	**192**	179	10	—	3
Other	**60**	16	43	1	—
Total	**2,837**	366	417	363	1,691

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

SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares and an unlimited number of preferred shares. No preferred shares have been issued by the Company as at September 30, 2026 (December 31, 2025 – $nil).

The following table summarizes the number of shares outstanding as at November 8, 2026:

Share Class	Shares Outstanding at November 8, 2026
Common shares	213,823,475

Share Pass-through Transactions

On March 5, 2026, one WEF limited partnership completed a share pass-through transaction that resulted in the disposition of 7,102,958 Strathcona common shares (the "**March Pass-through Transaction**"). Following the March Pass-through Transaction, WEF's ownership of Strathcona's outstanding common shares decreased from approximately 69.9% to approximately 66.6%.

The March Pass-through Transaction was comprised of a series of reorganizational steps, which included the issuance by Strathcona of 7,102,958 common shares to partners of the WEF limited partnership upon the dissolution of such limited partnership. Notwithstanding such issuance, the number of issued and outstanding common shares remained the same following completion of the March Pass-through Transaction.

On June 23, 2026, certain WEF limited partnerships completed a share pass-through transaction that resulted in the disposition of 13,551,243 Strathcona common shares (the **"June Pass-through Transaction**"). Following the June Pass-through Transaction, WEF's ownership of Strathcona's outstanding common shares decreased from approximately 66.6% to approximately 60.2%.

On October 6, 2026, certain WEF limited partnerships completed a share pass-through transaction that resulted in the disposition of 7,115,755 Strathcona common shares (the **"October Pass-through Transaction"**). Following the October Pass-through Transaction, WEF's ownership of Strathcona's outstanding common shares decreased from approximately 60.2% to approximately 56.9%.

Dividends

During the three and nine months ended September 30, 2026, Strathcona declared and paid dividends of $64 million ($0.30 per common share) and $193 million ($0.90 per common share), respectively ($64 million ($0.30 per common share) and $184 million ($0.86 per common share) for the three and nine months ended September 30, 2025).

On November 8, 2026, the Strathcona Board of Directors declared a quarterly dividend of $0.32 per common share to be paid on December 14, 2026 to all shareholders of record on December 4, 2026.

Normal Course Issuer Bid

On March 12, 2026, the Toronto Stock Exchange approved Strathcona's normal course issuer bid ("**NCIB**") to acquire up to 5% of its issued and outstanding shares (up to a maximum of approximately 10.7 million common shares of the Company). The NCIB commenced on March 17, 2026 and will terminate on March 16, 2027 or such earlier time as the maximum number of common shares has been purchased or Strathcona decides not to make any further purchases. For the three and nine months ended September 30, 2026, no common shares were repurchased under the NCIB. Subsequent to September 30, 2026, the Company repurchased and cancelled 400,000 common shares under its NCIB for consideration of $14 million.

SUMMARY OF QUARTERLY RESULTS

($ millions, unless otherwise indicated)	2026 Q3	2026 Q2	2026 Q1	2025 Q4	2025 Q3	2025 Q2	2025 Q1[1]	2024[1] Q4
Operating results (boe/d)								
Average production volumes	**123,486**	117,022	116,542	117,715	116,201	181,368	194,609	187,203
Continuing operations	**123,486**	117,022	116,542	117,679	115,584	108,926	115,859	111,013
Discontinued operations	**—**	—	—	36	617	72,442	78,750	76,190
Financial Results								
Oil and natural gas sales	**1,459**	1,486	1,121	937	1,012	1,209	1,459	1,293
Continuing operations	**1,459**	1,486	1,121	937	1,009	974	1,176	1,043
Discontinued operations	**—**	—	—	—	3	235	283	250
Net income (loss)	**298**	333	39	(99)	573	231	206	88
Continuing operations	**298**	333	39	(90)	144	158	153	50
Discontinued operations	**—**	—	—	(9)	429	73	53	38
Net income (loss) per share	**1.39**	1.55	0.18	(0.47)	2.68	1.08	0.96	0.41
Continuing operations	**1.39**	1.55	0.18	(0.42)	0.68	0.74	0.71	0.23
Discontinued operations	**—**	—	—	(0.05)	2.00	0.34	0.25	0.18
Operating Earnings	**371**	376	194	146	236	225	322	190
Continuing operations	**371**	376	194	138	227	127	251	137
Discontinued operations[2]	**—**	—	—	8	9	98	71	53
Free Cash Flow[2][3]	**286**	298	49	59	97	33	186	—
Continuing operations[2][3]	**286**	298	49	39	88	43	170	2
Discontinued operations[2][3]	**—**		—	20	9	(10)	16	(2)
Capital expenditures[3][4]	**239**	231	296	170	278	378	349	392
Decommissioning expenditures[4]	**9**	9	19	9	8	3	24	13

(1) Comparative periods have been revised to reflect current period presentation.
(2) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see the "*Specified Financial Measures*" section of this MD&A.
(3) Comparative periods have been revised to exclude land expenditures from capital expenditures.
(4) Includes continuing and discontinued operations.

Over the past eight quarters, the Company's oil and natural gas sales have fluctuated due to the volatility in the crude oil, condensate and natural gas benchmark prices, oil price differentials, changes in production, the Groundbirch Asset Sale, the Kakwa and Grande Prairie Asset Sales and the Vawn Acquisition. The Company's production has fluctuated due to asset acquisitions and dispositions, changes in its development capital spending levels and natural declines.

Net income (loss) has fluctuated over the past eight quarters primarily due to the changes in Funds from Operations, the Groundbirch Asset Sale, the Kakwa and Grande Prairie Asset Sales, the Vawn Acquisition, unrealized gains and losses from risk management contracts, which fluctuate with changes in forward market prices and foreign exchange rates, unrealized gain on marketable securities, which fluctuate with changes in listed share prices, 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 have fluctuated throughout the past eight quarters due to changes in the Company's development capital spending levels which vary based on a number of factors, including the prevailing commodity price environment.

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SPECIFIED FINANCIAL MEASURES

Non-GAAP and Other Financial Measures and Ratios

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

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

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

The term "**Effective royalty rate**" is calculated by dividing royalties by oil and natural gas sales, sale of purchased product and midstream revenue, net of blending and purchased product. 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. Quantitative reconciliations of Field Operating Income and Field Operating Netback to the most directly comparable GAAP financial measure, oil and natural gas sales, are contained under the headings "*Presentation of Continuing and Discontinued Operations*" and "*Segment Results*", respectively, of this MD&A.

"**Operating Earnings - Discontinued**" is considered a key financial metric for evaluating the profitability of Strathcona's discontinued business. "**Operating Earnings - Continuing**" is a GAAP financial measure as it is used by the Company's CODMs to evaluate profit or loss and is presented in the interim financial statements. A quantitative reconciliation of Operating Earnings - Discontinued to the most directly comparable GAAP financial measure, Oil and natural gas sales, is contained under the heading "*Presentation of Continuing and Discontinued Operations*" of this MD&A.

"**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 Operating Earnings and adjusted for DD&A, finance costs, gains and losses on risk management contracts – realized and gains and losses on foreign exchange - realized.

"Free Cash Flow" is a key financial metric for evaluating Strathcona's liquidity as it indicates the funds available for deleveraging, funding future growth, or shareholder returns. Free Cash Flow is derived from Operating Earnings and adjusted for DD&A, finance costs, gains and losses on risk management contracts – realized and gains and losses on foreign exchange - realized, capital expenditures and decommissioning costs.

Quantitative reconciliations of Funds from Operations and Free Cash Flow for both continuing and discontinued operations to the most directly comparable GAAP financial measure, Operating Earnings, are set forth below.

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Operating Earnings - Continuing	**371**	227	376	**941**	606
Depletion, depreciation and amortization	**150**	151	140	**432**	454
Finance costs	**9**	14	10	**30**	41
Gain (loss) on risk management contracts - realized	**7**	(20)	12	**35**	(25)
Foreign exchange (loss) gain - realized	**(3)**	2	—	**(2)**	(2)
Funds from Operations - Continuing	**534**	374	538	**1,436**	1,074
Capital expenditures[(1)]	**(239)**	(278)	(231)	**(766)**	(755)
Decommissioning costs	**(9)**	(8)	(9)	**(37)**	(33)
Free Cash Flow - Continuing	**286**	88	298	**633**	286

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Operating Earnings - Discontinued	**—**	9	—	**—**	178
Depletion, depreciation and amortization	**—**	—	—	**—**	90
Finance costs	**—**	—	—	**—**	13
Funds from Operations - Discontinued	**—**	9	—	**—**	281
Capital expenditures[(1)]	**—**	—	—	**—**	(250)
Decommissioning costs	**—**	—	—	**—**	(2)
Free Cash Flow - Discontinued	**—**	9	—	**—**	29

The following table reconciles Operating Earnings, Funds from Operations and Free Cash Flow from continuing and discontinued operations:

($ millions, unless otherwise indicated)	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025	June 30, 2026	**September 30, 2026**	September 30, 2025
Operating Earnings	**371**	236	376	**941**	784
Depletion, depreciation and amortization	**150**	151	140	**432**	544
Finance costs	**9**	14	10	**30**	54
Gain (loss) on risk management contracts - realized	**7**	(20)	12	**35**	(25)
Foreign exchange (loss) gain - realized	**(3)**	2	—	**(2)**	(2)
Funds from Operations	**534**	383	538	**1,436**	1,355
Capital expenditures[(1)]	**(239)**	(278)	(231)	**(766)**	(1,005)
Decommissioning costs	**(9)**	(8)	(9)	**(37)**	(35)
Free Cash Flow	**286**	97	298	**633**	315

(1) Comparative periods have been revised to exclude land expenditures from capital expenditures.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

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

On January 1, 2026, Strathcona adopted Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures, relating to settling financial liabilities using an electronic payment system and the assessment of contractual cash flow characteristics of financial assets. There was no material impact to the Company's financial statements.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Strathcona is required to comply with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*. The certification of interim filings for the interim period ended September 30, 2026 requires that Strathcona disclose in the MD&A any changes in Strathcona's internal controls over financial reporting ("**ICFR**") that occurred during the period that have materially affected, or are reasonably likely to materially affect, Strathcona's ICFR. Strathcona confirms that no such changes were made to its ICFR during the three months ended September 30, 2026.

ADVISORIES REGARDING OIL & GAS INFORMATION

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

National Instrument 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.

The Company's three and nine months ended average daily production volumes for 2026 and 2025, and the references to "natural gas", "crude oil" and "total liquids", reported in this MD&A consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 6 mcf : 1 bbl where applicable:

	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025[1]	June 30, 2026	**September 30, 2026**	September 30, 2025[1]
Cold Lake segment					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**—**	—	—	**—**	—
Bitumen (bbl/d)	**64,776**	61,157	62,782	**62,990**	60,919
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**64,776**	61,157	62,782	**62,990**	60,919
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**64,776**	61,157	62,782	**62,990**	60,919
Lloydminster Thermal segment[1]					
Heavy crude oil (bbl/d)	**38,547**	31,937	33,571	**35,586**	29,216
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**38,547**	31,937	33,571	**35,586**	29,216
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**38,547**	31,937	33,571	**35,586**	29,216
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**38,547**	31,937	33,571	**35,586**	29,216
Lloydminster Conventional segment[1]					
Heavy crude oil (bbl/d)	**19,747**	22,006	20,182	**20,008**	22,767
Light and medium crude oil (bbl/d)	**48**	1	56	**58**	47
Total crude oil (bbl/d)	**19,795**	22,007	20,238	**20,066**	22,814
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**30**	42	25	**26**	30
Total liquids (bbl/d)	**19,825**	22,049	20,263	**20,092**	22,844
Conventional natural gas (mcf/d)	**2,030**	2,642	2,436	**2,244**	2,853
Total (boe/d)	**20,163**	22,489	20,669	**20,466**	23,320
Discontinued operations					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	16
Light and medium crude oil (bbl/d)	**—**	17	—	**—**	267
Total crude oil (bbl/d)	**—**	17	—	**—**	283
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**—**	424	—	**—**	21,523
Total liquids (bbl/d)	**—**	441	—	**—**	21,806
Conventional natural gas (mcf/d)	**—**	1,059	—	**—**	171,069
Total (boe/d)	**—**	617	—	**—**	50,317

(1) Comparative period has been revised to reflect current period presentation.

	Three Months Ended			Nine Months Ended	
	September 30, 2026	September 30, 2025[1]	June 30, 2026	**September 30, 2026**	September 30, 2025[1]
Consolidated					
Heavy crude oil (bbl/d)	**58,294**	53,943	53,753	**55,594**	51,999
Light and medium crude oil (bbl/d)	**48**	18	56	**58**	314
Total crude oil (bbl/d)	**58,342**	53,961	53,809	**55,652**	52,313
Bitumen (bbl/d)	**64,776**	61,157	62,782	**62,990**	60,919
NGLs (bbl/d)	**30**	466	25	**26**	21,553
Total liquids (bbl/d)	**123,148**	115,584	116,616	**118,668**	134,785
Conventional natural gas (mcf/d)	**2,030**	3,701	2,436	**2,244**	173,922
Total (boe/d)	**123,486**	116,201	117,022	**119,042**	163,772

(1) Comparative period has been revised to reflect current period presentation.

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", "should", "project", "believe", "depends", "could", "guidance", "plan", "manages" 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 acquisition of Greenfire, including the proposed funding in respect thereof; WEF's expected ownership of Strathcona following closing of the acquisition; the anticipated production and operating performance of the Meota Central facility and other development projects, including the Plover Lake central processing facility expansion; the Company's normal course issuer bid; the declaration and payment of dividends, including the amount and timing thereof; the Company's use of hedging arrangements; the amount and timing of future contingent consideration payments in connection with the Vawn Acquisition; the Company's ability to meet current and future obligations, including making scheduled principal and interest payments, to fund planned capital expenditures and to fund the other needs of the business; the Company's ability to remedy its working capital deficiency; future liquidity and financial capacity; anticipated proceeds from financial instruments, including commodity contracts; and sources of funding for the Company's capital program, the terms of Strathcona's future contractual obligations, including its obligations under the Credit Agreement 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: with respect to the proposed acquisition of Greenfire the completion of the Transaction on anticipated terms and timing, or at all, the receipt of required approvals and the availability of borrowings under the existing Credit Facilities to fund the cash consideration and outstanding indebtedness of Greenfire; the success of Strathcona's operations and growth and expansion projects; expectations regarding production growth, future well production rates and reserve volumes; expectations regarding Strathcona's capital program; Strathcona's ability to declare and pay dividends; expectations regarding the impact of tariffs on Strathcona's operations and its ability to effectively mitigate the impact thereof; the outlook for general economic trends, industry trends, prevailing and future commodity prices, foreign exchange rates and interest rates; prevailing and future royalty regimes and tax laws; fluctuations in energy prices based on worldwide demand and geopolitical events; the impact of inflation; the integrity and reliability of Strathcona's assets; decommissioning obligations; Strathcona's ability to comply with its financial covenants; and the governmental, regulatory and legal environment, including expectations regarding the current and future carbon tax regime and regulations.

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 conflict in the Middle East, including disruptions to shipping through the Strait of Hormuz, ongoing Russia/Ukraine conflict, and other heightened geopolitical risks, including the imposition of tariffs or other trade barriers, and the ability of the Company to carry on operations as contemplated in light of the foregoing; determinations by the Organization of the Petroleum Exporting Countries and other countries as to production levels; unanticipated operating results or production declines; delays or cost overruns in, or failure of new facilities to perform as anticipated, including the Meota Central facility; changes in tax or environmental laws, climate change, royalty rates or other regulatory matters; changes in Strathcona's development plans or by third party operators of Strathcona's properties; failure to achieve anticipated results of its operations; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of the Company's acquisitions, dispositions or corporate reorganizations; failure to execute the Company's growth strategy and objectives; 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, unfavorable or a lack of access to capital markets or other sources of capital; increased costs; a lack of adequate insurance coverage; the impact of competitors; and the other factors discussed under the "*Risk Factors"* section in the Company's management's discussion and analysis and annual information form for the year ended December 31, 2025, a copy of each of which is available on the internet under the Company's SEDAR+ profile at www.sedarplus.ca.

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

ADDITIONAL INFORMATION

Additional information about Strathcona, including Strathcona's annual information form for the year ended December 31, 2025 and the interim financial statements, can be found on the internet under the Company's SEDAR+ profile at www.sedarplus.ca and on the Company's website at www.strathconaresources.com.