STRATHCONA
RESOURCES LTD

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 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 August 5, 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 six months ended June 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 60.2% of the Company's common shares were owned by certain limited partnerships comprising Waterous Energy Fund (collectively, "**WEF**").

RECENT DEVELOPMENTS

On July 30, 2026, certain amendments were made to the Credit Facilities (as defined in the "*Capital Resources*" section of this MD&A), including an extension of the maturity date to December 31, 2030 and a reset and increase in the amount of the accordion feature to $750 million.

GUIDANCE

The following table sets forth production and capital expenditures guidance for 2026:

	2026 Guidance(1)	Revised 2026 Guidance
Annual average production (Mboe/d)	120 - 130	**122 - 128**
Capital expenditures ($ millions)	1,000	**1,000**

(1) As announced March 11, 2026 and disclosed in the Company's MD&A for the three months and year ended December 31, 2025 and 2024.

PRESENTATION OF CONTINUING AND DISCONTINUED OPERATIONS

During the six months and 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 six months months ended June 30, 2026 and 2025 and the three months ended March 31, 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 June 30, 2026 Cont.	Disc.	Total	Three Months Ended June 30, 2025 Cont.	Disc.	Total	Three Months Ended March 31, 2026 Cont.	Disc.	Total
Revenues and other income									
Oil and natural gas sales	1,486	—	**1,486**	974	235	**1,209**	1,121	—	**1,121**
Sale of purchased products	82	—	**82**	14	—	**14**	4	—	**4**
Royalties	(232)	—	**(232)**	(96)	(9)	**(105)**	(142)	—	**(142)**
Oil and natural gas revenues	1,336	—	**1,336**	892	226	**1,118**	983	—	**983**
Gain (loss) on risk management contracts	52	—	**52**	19	—	**19**	(71)	—	**(71)**
Midstream revenue	9	—	**9**	7	—	**7**	9	—	**9**
Other income	—	—	**—**	5	—	**5**	—	—	**—**
	1,397	—	**1,397**	923	226	**1,149**	921	—	**921**
Expenses									
Purchased product	80	—	**80**	14	—	**14**	4	—	**4**
Blending costs	417	—	**417**	250	—	**250**	306	—	**306**
Production and operating	171	—	**171**	181	39	**220**	185	—	**185**
Transportation and processing	96	—	**96**	94	56	**150**	94	—	**94**
General and administrative	26	—	**26**	21	6	**27**	28	—	**28**
Interest	29	—	**29**	46	—	**46**	28	—	**28**
Transaction related costs	1	—	**1**	14	5	**19**	—	—	**—**
Finance costs	10	—	**10**	15	5	**20**	11	—	**11**
Depletion, depreciation and amortization	140	—	**140**	156	22	**178**	142	—	**142**
Foreign exchange (gain) loss	(2)	—	**(2)**	(40)	—	**(40)**	4	—	**4**
Change in decommissioning liabilities	1	—	**1**	—	—	**—**	13	—	**13**
Loss on contingent consideration	—			—			42	—	**42**
	969	—	**969**	751	133	**884**	857	—	**857**
Gain on marketable securities	—	—	**—**	25	—	**25**	—	—	**—**
Gain on sale of assets, net	—	—	**—**	—	5	**5**	—	—	**—**
Loss on settlement of other obligations	—	—	**—**	—	(1)	**(1)**	—	—	**—**
Income before income taxes	428	—	**428**	197	97	**294**	64	—	**64**
Income tax expense	95	—	**95**	39	24	**63**	25	—	**25**
Income and comprehensive income	333	—	**333**	158	73	**231**	39	—	**39**

	Six Months Ended June 30, 2026			Six Months Ended June 30, 2025		
($ millions, unless otherwise indicated)	Cont.	Disc.	**Total**	Cont.	Disc.	**Total**
Revenues and other income						
Oil and natural gas sales	2,607	—	**2,607**	2,151	517	**2,668**
Sale of purchased product	86	—	**86**	21	—	**21**
Royalties	(374)	—	**(374)**	(208)	(34)	**(242)**
Oil and natural gas revenues	2,319	—	**2,319**	1,964	483	**2,447**
Loss on risk management contracts	(19)	—	**(19)**	(59)	—	**(59)**
Midstream revenue	18	—	**18**	7	—	**7**
Other income	—	—	**—**	6	—	**6**
	2,318	—	**2,318**	1,918	483	**2,401**
Expenses						
Purchased product	84	—	**84**	22	—	**22**
Blending costs	723	—	**723**	576	—	**576**
Production and operating	356	—	**356**	364	88	**452**
Transportation and processing	190	—	**190**	182	111	**293**
General and administrative	54	—	**54**	40	12	**52**
Interest	57	—	**57**	84	—	**84**
Transaction related costs	1	—	**1**	15	4	**19**
Finance costs	21	—	**21**	27	13	**40**
Depletion, depreciation and amortization	282	—	**282**	303	90	**393**
Foreign exchange loss (gain)	2	—	**2**	(41)	—	**(41)**
Change in decommissioning liabilities	14	—	**14**	—	—	**—**
Contingent consideration	42	—	**42**	—	—	**—**
	1,826	—	**1,826**	1,572	318	**1,890**
Gain on marketable securities	—	—	**—**	47	—	**47**
Gain on sale of assets, net	—	—	**—**	—	5	**5**
Loss on settlement of other obligations	—	—	**—**	—	(1)	**(1)**
Income before income taxes	492	—	**492**	393	169	**562**
Income tax expense	120	—	**120**	82	44	**126**
Income and comprehensive income	372	—	**372**	311	125	**436**

The following tables reconcile total operating earnings for the three and six months ended June 30, 2026 and 2025 and the three months ended March 31, 2026.

($ millions, unless otherwise indicated)	Three Months Ended June 30, 2026 Cont.	Disc.	Total	Three Months Ended June 30, 2025 Cont.	Disc.	Total	Three Months Ended March 31, 2026 Cont.	Disc.	Total
Revenues									
Oil and natural gas sales	1,486	—	**1,486**	974	235	**1,209**	1,121	—	**1,121**
Sale of purchased product	82	—	**82**	14	—	**14**	4	—	**4**
Blending costs	(417)	—	**(417)**	(250)	—	**(250)**	(306)	—	**(306)**
Purchased product	(80)	—	**(80)**	(14)	—	**(14)**	(4)	—	**(4)**
Midstream revenue	9	—	**9**	7	—	**7**	9	—	**9**
Oil and natural gas sales, net of blending[(1)]	1,080	—	**1,080**	731	235	**966**	824	—	**824**
Expenses									
Royalties	232	—	**232**	96	9	**105**	142	—	**142**
Production and operating	171	—	**171**	181	39	**220**	185	—	**185**
Transportation and processing	96	—	**96**	94	56	**150**	94	—	**94**
Field operating income[(1)]	581	—	**581**	360	131	**491**	403	—	**403**
Depletion, depreciation and amortization	140	—	**140**	156	22	**178**	142	—	**142**
General and administrative	26	—	**26**	21	6	**27**	28	—	**28**
Finance costs	10	—	**10**	15	5	**20**	11	—	**11**
Other income	—	—	**—**	(5)	—	**(5)**	—	—	**—**
Interest	29	—	**29**	46	—	**46**	28	—	**28**
Operating earnings	376	—	**376**	127	98	**225**	194	—	**194**

($ millions, unless otherwise indicated)	Six Months Ended June 30, 2026 Cont.	Disc.	Total	Six Months Ended June 30, 2025 Cont.	Disc.	Total
Revenues						
Oil and natural gas sales	2,607	—	**2,607**	2,151	517	**2,668**
Sale of purchased product	86	—	**86**	21	—	**21**
Blending costs	(723)	—	**(723)**	(576)	—	**(576)**
Purchased product	(84)	—	**(84)**	(22)	—	**(22)**
Midstream revenue	18	—	**18**	7	—	**7**
Oil and natural gas sales, net of blending[(1)]	1,904	—	**1,904**	1,581	517	**2,098**
Expenses						
Royalties	374	—	**374**	208	34	**242**
Production and operating	356	—	**356**	364	88	**452**
Transportation and processing	190	—	**190**	182	111	**293**
Field operating income[(1)]	984	—	**984**	827	284	**1,111**
Depletion, depreciation and amortization	282	—	**282**	303	90	**393**
General and administrative	54	—	**54**	40	12	**52**
Finance costs	21	—	**21**	27	13	**40**
Other income	—	—	**—**	(6)	—	**(6)**
Interest	57	—	**57**	84	—	**84**
Operating earnings	570	—	**570**	379	169	**548**

(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			Six Months Ended	
	June 30, 2026	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Bitumen (bbl/d)	**62,782**	56,628	61,375	**62,083**	60,799
Heavy oil (bbl/d)	**53,753**	51,479	54,695	**54,222**	50,986
Condensate and light oil (bbl/d)	**69**	123	78	**73**	71
Total oil production (bbl/d)	**116,604**	108,230	116,148	**116,378**	111,856
Other NGLs (bbl/d)	**12**	44	15	**14**	23
Natural gas (mcf/d)	**2,436**	3,911	2,268	**2,352**	2,961
Total (boe/d) - continuing operations	**117,022**	108,926	116,542	**116,783**	112,373
Total (boe/d) - discontinued operations	**—**	72,442	—	**—**	75,579
Total (boe/d)	**117,022**	181,368	116,542	**116,783**	187,952
% liquids - continuing operations	**99.7 %**	99.4 %	99.7 %	**99.7 %**	99.6 %

Production volumes from continuing operations increased 7% (or 8,096 boe per day) for the three months ended June 30, 2026 to an average of 117,022 boe per day compared to 108,926 boe per day for the same period of 2025. The increase was driven by higher production at the Lloydminster Thermal segment, 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 6,457 boe per day during the second quarter of 2026. This increase was also impacted by production increases in the current period and a planned turnaround in the comparable period at the Cold Lake segment, partially offset by development challenges and a turnaround in the Lloydminster Conventional segment.

Production volumes from continuing operations increased 4% (or 4,410 boe per day) for the six months ended June 30, 2026 to an average of 116,783 boe per day compared to 112,373 boe per day for the same period of 2025. The increase was primarily due to production added from the Vawn Acquisition which contributed average production of 6,305 boe per day for the six months ended June 30, 2026. These increases were partially offset by unplanned outages and plant issues at the Cold Lake segment.

Production volumes from continuing operations increased by 480 boe per day during the three months ended June 30, 2026 to an average of 117,022 boe per day compared to 116,542 boe per day for the three months ended March 31, 2026. The increase was primarily due to production gains at the Cold Lake segment, partially offset by treating issues and power outages experienced at the Lloydminster Thermal segment.

SALES VOLUMES

	Three Months Ended			Six Months Ended	
	June 30, 2026	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Bitumen (bbl/d)	**62,390**	56,427	61,829	**62,111**	60,587
Heavy oil (bbl/d)	**53,253**	54,094	55,854	**54,546**	52,549
Condensate and light oil (bbl/d)	**69**	123	78	**73**	71
Total oil production (bbl/d)	**115,712**	110,644	117,761	**116,730**	113,207
Other NGLs (bbl/d)	**12**	44	15	**14**	23
Natural gas (mcf/d)	**2,436**	3,911	2,268	**2,352**	2,961
Total (boe/d) - continuing operations	**116,130**	111,340	118,155	**117,136**	113,724
Total (boe/d) - discontinued operations	**—**	72,466	—	**—**	75,591
Total (boe/d)	**116,130**	183,806	118,155	**117,136**	189,315

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 June 30, 2026, there was a buildup of pipeline inventory and scheduled turnarounds which reduced overall sales volumes. For the six months ended June 30, 2026, pipeline inventory was sold to take advantage of higher market pricing, resulting in sales volumes exceeding production volumes.

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	June 30, 2026	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI(1)	**92.77**	63.74	71.93	**82.35**	67.58
WCS Hardisty(2)	**78.11**	53.46	57.76	**67.94**	56.11
WCS USGC(3)	**87.35**	61.00	65.21	**76.28**	64.37
WTI-WCS Hardisty differential	**(14.66)**	(10.28)	(14.17)	**(14.41)**	(11.47)
WTI-WCS USGC differential	**(5.42)**	(2.74)	(6.72)	**(6.07)**	(3.21)
NYMEX-AECO differential (US$/MMbtu)(4)	**(1.92)**	(2.10)	(3.41)	**(2.66)**	(2.25)
Condensate differential(5)	**2.68**	(0.29)	(0.53)	**1.08**	(0.91)
Average Exchange rate (C$/US$)	**1.3836**	1.3840	1.3716	**1.3776**	1.4094
CAD$/bbl unless otherwise indicated					
WTI(1)	**128.25**	88.19	98.65	**113.45**	95.33
WCS Hardisty(2)	**107.95**	73.96	79.23	**93.59**	79.13
WCS USGC(3)	**120.74**	84.40	89.44	**105.09**	90.80
AECO 5A (C$/gj)(6)	**1.55**	1.60	1.90	**1.72**	1.83
Condensate par at Edmonton	**131.96**	87.77	97.93	**114.94**	94.02
AESO weighted average pool price (C$/MWh)(7)	**30.12**	41.26	32.51	**31.32**	41.24
CORRA (%)(8)	**2.28**	2.75	2.27	**2.28**	2.90

(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 second quarter of 2026, WTI pricing averaged US$92.77 per bbl, a 29% increase from the first quarter of 2026. The primary driver of this increase was supply disruptions in the Middle East, specifically the closure of the Strait of Hormuz, a critical energy transit choke point handling 20% of global oil supply. This disruption constrained global crude oil supply and contributed to significant production shut-ins in the Middle East, tightening physical crude markets and increasing crude oil risk premiums during the quarter. Prices began to moderate towards the end of the second quarter of 2026 as tensions in the Middle East eased, and traffic through the Strait of Hormuz improved.

The WTI-WCS USGC differential narrowed by 19%, when compared the first quarter of 2026, due to global supply constraints caused by conflicts in the Middle East, resulting in stronger refinery run economics. The WTI-WCS Hardisty differential remained relatively consistent, widening by 3% in the second quarter of 2026, when compared to the first quarter of 2026, primarily due to an increase in pipeline apportionment indicating restricted egress out of the Western Canadian Sedimentary Basin.

AECO 5A natural gas prices decreased in the second quarter of 2026 by 18%, when compared to the first quarter of 2026, primarily due to the strengthening of Western Canadian natural gas supply, seasonal heating demand declines following winter months and ongoing regional transportation constraints.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales – Net of Blending

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2026**	 June 30, 2025	 March 31, 2026	Six Months Ended **June 30, 2026**	 June 30, 2025
Bitumen blend	**875**	548	647	**1,522**	1,270
Heavy oil, blended and raw	**610**	424	473	**1,083**	879
Condensate and light oil	**1**	1	—	**1**	1
Natural gas	**—**	1	1	**1**	1
Oil and natural gas sales	**1,486**	974	1,121	**2,607**	2,151
Midstream revenue	**9**	7	9	**18**	7
Gain (loss) on purchased product	**2**	—	—	**2**	(1)
Bitumen – blending cost	**(338)**	(208)	(251)	**(589)**	(489)
Heavy oil – blending cost	**(79)**	(42)	(55)	**(134)**	(87)
Oil and natural gas sales, net of blending - continuing operations(1)	**1,080**	731	824	**1,904**	1,581
Oil and natural gas sales, net of blending - discontinued operations(1)	**—**	235	—	**—**	517
Oil and natural gas sales, net of blending(1)	**1,080**	966	824	**1,904**	2,098

(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 48% (or $349 million) for the three months ended June 30, 2026 to $1,080 million compared to $731 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 20% (or $323 million) for the six months ended June 30, 2026 to $1,904 million compared to $1,581 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 31% (or $256 million) for the three months ended June 30, 2026 to $1,080 million compared to $824 million for the three months ended March 31, 2026. This increase was primarily due to stronger oil benchmark pricing, partially offset by increased blending costs due to higher condensate benchmark pricing and a decrease in sales volumes.

Average Realized Prices

($ millions, unless otherwise indicated)	Three Months Ended June 30, 2026	June 30, 2025	March 31, 2026	Six Months Ended June 30, 2026	June 30, 2025
Bitumen blend ($/bbl)(1)	**94.61**	66.24	71.21	**83.02**	71.18
Heavy oil, blended and raw ($/bbl)(1)	**109.72**	77.68	83.08	**96.16**	83.24
Condensate and light oil ($/bbl)	**97.89**	89.83	—	**80.67**	88.80
Realized oil ($/bbl)	**101.56**	71.94	76.84	**89.16**	76.79
Other natural gas liquids ($/bbl)	**—**	16.65	—	**—**	19.10
Natural gas ($/mcf)	**—**	2.25	2.23	**1.78**	2.04
Midstream revenue ($/bbl)	**0.82**	0.66	0.84	**0.83**	0.32
Combined ($/boe) - continuing operations	**102.24**	72.18	77.46	**89.81**	76.82
Combined ($/boe) - discontinued operations	**—**	35.60	—	**—**	37.82
Combined ($/boe)	**102.24**	57.75	77.46	**89.81**	59.27

(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 six months ended June 30, 2026, combined realized price from continuing operations increased 42% (or $30.06 per boe) and 17% (or $12.99 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 increased 32% (or $24.78 per boe) for the three months ended June 30, 2026 compared to the three months ended March 31, 2026. This increase was primarily attributable to higher average WCS Hardisty and USGC benchmark prices, partially offset by increased per barrel blend costs as the result of higher condensate benchmark pricing.

ROYALTIES

($ millions, unless otherwise indicated)	Three Months Ended June 30, 2026	June 30, 2025	March 31, 2026	Six Months Ended June 30, 2026	June 30, 2025
Crown royalties	**158**	76	112	**270**	159
Freehold royalties	**9**	5	5	**14**	12
Gross overriding royalties	**57**	9	21	**78**	24
Other royalties	**8**	6	4	**12**	13
Royalties - continuing operations	**232**	96	142	**374**	208
Royalties - discontinued operations	**—**	9	—	**—**	34
Royalties	**232**	105	142	**374**	242
Effective royalty rate (%) - continuing operations(1)	**21.4 %**	13.1 %	17.2 %	**19.6 %**	13.2 %

(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 six months ended June 30, 2026, the effective royalty rate from continuing operations increased to 21.4% and 19.6%, from 13.1% and 13.2%, respectively, in the comparable periods in 2025. These increases were primarily attributable to higher commodity benchmark pricing.

The effective royalty rate increased to 21.4% for the three months ended June 30, 2026, from 17.2% for the three months ended March 31, 2026. This increase was primarily due to an increase in commodity benchmark pricing.

PRODUCTION AND OPERATING EXPENSES

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2026**	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Production and operating – Energy	**62**	58	77	**139**	132
Production and operating – Non-energy	**109**	123	108	**217**	232
Production and operating expenses - continuing operations	**171**	181	185	**356**	364
Production and operating expenses - discontinued operations	**—**	39	—	**—**	88
Production and operating expenses	**171**	220	185	**356**	452
Production and operating – Energy - continuing operations ($/boe)	**6.03**	5.73	7.19	**6.61**	6.41
Production and operating – Non-energy - continuing operations ($/boe)	**10.32**	12.10	10.17	**10.25**	11.24
Production and operating expenses - continuing operations ($/boe)	**16.35**	17.83	17.36	**16.86**	17.65

Production and operating expenses from continuing operations decreased 6% (or $10 million) for the three months ended June 30, 2026 to $171 million ($16.35 per boe) from $181 million ($17.83 per boe) in the same period of 2025. Energy expenses increased by 7% (or $4 million) primarily due to an increase in carbon tax expense. In the comparable period of 2025, the Company acquired carbon credits, which reduced its carbon tax obligation relative to legislated rates, and as the result of the Vawn Acquisition, which contributed $4 millions of costs, in the current quarter. These increases were partially offset by a decrease in electricity and power costs as the result of lower benchmark prices. Non-energy expenses decreased 11% (or $14 million) primarily due to a decrease in surface maintenance and chemical costs at the Cold Lake segment, partially offset by an increase in operating costs of $4 million attributable to the Vawn Acquisition.

Production and operating expenses from continuing operations decreased 2% (or $8 million) for the six months ended June 30, 2026 to $356 million ($16.86 per boe) from $364 million ($17.65 per boe) in the same period of 2025. Energy expenses increased by 5% (or $7 million) primarily due to an increase in carbon tax expense. In the comparable period of 2025, the Company acquired carbon credits, which reduced its carbon tax obligation relative to legislated rates. Additionally, the Vawn Acquisition contributed incremental carbon tax expense and fuel costs of $6 million and $5 million, respectively. These increases were partially offset by a decrease in electricity and power costs due to lower benchmark pricing. Non-energy expenses decreased 6% (or $15 million) primarily due to lower chemical and surface maintenance costs in the Cold Lake segment, partially offset by an increase in operating costs of $11 million as the result of the Vawn Acquisition, and the acquisition of HRT.

Production and operating expenses from continuing operations decreased 8% (or $14 million) for the three months ended June 30, 2026 to $171 million ($16.35 per boe) from $185 million ($17.36 per boe) for the three months ended March 31, 2026. Energy expenses decreased 19% (or $15 million) primarily due to a decrease in fuel costs as the result of lower benchmark pricing, partially offset by an increase in carbon tax expense. Non-energy expenses increased 1% (or $1 million) primarily due to an increase in surface maintenance costs and chemical expenses, partially offset by a decrease in internal labor costs.

TRANSPORTATION EXPENSES

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2026**	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Transportation expenses - continuing operations	**96**	94	94	**190**	182
Transportation and processing expenses - discontinued operations	**—**	56	—	**—**	111
Transportation and processing expenses	**96**	150	94	**190**	293
$ per boe - continuing operations	**9.08**	9.30	8.82	**8.95**	8.85

Transportation expenses from continuing operations increased 2% (or $2 million) for the three months ended June 30, 2026 to $96 million ($9.08 per boe) compared to $94 million ($9.30 per boe) in the same period of 2025. This increase was primarily attributable to incremental pipeline costs of $2 million associated with the Vawn Acquisition, higher rail transportation due to increased rail car maintenance costs and fuel surcharges, higher bitumen transportation as the result of increased sales volumes at Lindbergh and Orion during the current quarter and the application of make-up rights in the comparable period of 2025.

Transportation expenses from continuing operations increased 4% (or $8 million) for the six months ended June 30, 2026 to $190 million ($8.95 per boe) compared to $182 million ($8.85 per boe) in the same period of 2025. This increase was primarily attributable to incremental pipeline costs of $4 million associated with the Vawn Acquisition, higher rail transportation due to increased rail car maintenance costs and fuel surcharges and the utilization of make-up rights in the comparable period of 2025.

Transportation expenses from continuing operations increased 2% (or $2 million) for the three months ended June 30, 2026 to $96 million ($9.08 per boe) from $94 million ($8.82 per boe) in the three months ended March 31, 2026. This increase was primarily attributable to higher rail transportation costs due to increased rail car maintenance and fuel surcharges and higher trucking costs due to an increase in trucking rates.

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

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2026**	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Depletion expense	**131**	146	134	**265**	284
Depreciation and amortization expense	**9**	10	8	**17**	19
DD&A - continuing operations	**140**	156	142	**282**	303
DD&A - discontinued operations	**—**	22	—	**—**	90
DD&A	**140**	178	142	**282**	393
$ per boe - continuing operations	**13.22**	15.36	13.35	**13.29**	14.73

DD&A expense from continuing operations decreased 10% (or $16 million) for the three months ended June 30, 2026 to $140 million ($13.22 per boe) compared to $156 million ($15.36 per boe) for the same period of 2025. For the six months ended June 30, 2026, DD&A expense from continuing operations decreased 7% (or $21 million) to $282 million ($13.29 per boe), compared to $303 million ($14.73 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 June 30, 2026, decreased 1% (or $2 million) to $140 million ($13.22 per boe) compared to $142 million ($13.35 per boe) for the three months ended March 31, 2026. This decrease was primarily due to lower sales volumes.

GENERAL AND ADMINISTRATIVE EXPENSES (“G&A”)

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2026**	June 30, 2025	March 31, 2026	Six Months Ended **June 30, 2026**	June 30, 2025
G&A expenses - continuing operations	**26**	21	28	**54**	40
G&A expenses - discontinued operations	**—**	6	—	**—**	12
G&A expenses	**26**	27	28	**54**	52
$ per boe - continuing operations	**2.43**	2.09	2.65	**2.54**	1.96

For the three months ended June 30, 2026, G&A expenses from continuing operations increased 24% (or $5 million) compared to the same period of 2025. This increase was primarily due to the reallocation of corporate costs across the business following the sale of the Montney segment.

For the six months ended June 30, 2026, G&A expenses from continuing operations increased 35% (or $14 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 June 30, 2026 decreased 7% (or $2 million) compared to the three months ended March 31, 2026. This decrease was primarily due to the payment of Company's annual bonus in the first quarter of 2026.

INTEREST

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2026**	June 30, 2025	March 31, 2026	Six Months Ended **June 30, 2026**	June 30, 2025
Interest	**29**	46	28	**57**	84
Weighted average interest rate (%)	**4.8 %**	5.6 %	4.7 %	**4.7 %**	5.7 %

For the three and six months ended June 30, 2026, interest expense decreased 37% (or $17 million) and 32% (or $27 million), respectively, when compared to the same periods of 2025. These decreases were primarily attributable to lower debt balances and lower overall average interest rates.

Interest expense increased 4% (or $1 million) to $29 million for the three months ended June 30, 2026, compared to $28 million for the three months ended March 31, 2026. The increase in interest expense was due higher average interest rates, offset by the impact of lower debt balances.

During the six months ended June 30, 2026, the Company recorded $57 million in interest expense on the Credit Facilities (as defined in the "*Capital Resources*" section of this MD&A) (June 30, 2025 - $60 million), and $nil in interest expense on the senior notes (June 30, 2025 – $24 million).

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

TAX POOLS

As at June 30, 2026, the Company had approximately $2,522 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	**June 30, 2026**	December 31, 2025
Canadian oil and gas property expenditures(1)	10%	**306**	254
Canadian development expenditures(1)	30%	**306**	165
Canadian exploration expenditures(1)	100%	**9**	3
Undepreciated capital costs(2)	4% - 55%	**1,292**	1,232
Non-capital losses	100%	**375**	897
Other(3)		**234**	239
Total tax pools		**2,522**	2,790

(1) Amount is net of tax pools where deductibility is uncertain.
(2) As at June 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			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2026**	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Drilling, completion and equipping	**94**	215	132	**226**	414
Facilities and pipelines	**106**	138	128	**234**	258
Recompletion, workovers and polymer powder	**18**	13	16	**34**	32
Capitalized G&A and other expenditures	**15**	13	22	**37**	25
Capital expenditures(1)	**233**	379	298	**531**	729

(1) Capital expenditures includes continuing and discontinued operations.

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

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2026**	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Cold Lake	**69**	98	78	**147**	187
Lloydminster Thermal	**130**	120	160	**290**	211
Lloydminster Conventional	**33**	27	60	**93**	81
Corporate	**1**	—	—	**1**	—
Capital expenditures - continuing operations	**233**	245	298	**531**	479
Capital expenditures - discontinued operations	**—**	134	—	**—**	250
Capital expenditures	**233**	379	298	**531**	729

For the three months ended June 30, 2026, drilling, completion and equipping activities accounted for 40% of capital expenditures as the Company drilled 38 new wells during the second quarter of 2026; 13 in Cold Lake, 16 in Lloydminster Thermal and 9 in Lloydminster Conventional. For the six months ended June 30, 2026, drilling, completion and equipping activities accounted for 43% of capital expenditures as the Company drilled 123 new wells during the year; 25 in Cold Lake, 43 in Lloydminster Thermal and 55 in Lloydminster Conventional.

For the three and six months ended June 30, 2026, facilities and pipeline expenditures accounted for 45% and 44% of capital expenditures, respectively, and related primarily to the construction of the Meota Central processing facility, the Plover Lake central processing facility expansion, and one-time steam generation expansion and debottlenecking at Lindbergh.

DECOMMISSIONING EXPENDITURES

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

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2026**	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
Alberta	**4**	1	4	**8**	13
British Columbia	**1**	2	14	**15**	13
Saskatchewan	**4**	—	1	**5**	1
Total decommissioning expenditures(1)	**9**	3	19	**28**	27

(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 Western Canadian Select ("**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 six months ended June 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 second quarter, $42 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

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 - Dec 1, 2026	Floor	CORRA	2.25%
1,500 million	Dec 1, 2026 - May 1, 2028	Floor	CORRA	2.75%
1,500 million	May 1, 2028 - Dec 1, 2031	Swaption(1)	CORRA	3.09%

(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 June 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			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2026**	June 30, 2025	March 31, 2026	**June 30, 2026**	June 30, 2025
(Gain) loss on risk management contracts - realized	**(12)**	5	(16)	**(28)**	6
(Gain) loss on risk management contracts - unrealized	**(40)**	(24)	87	**47**	53
Total (gain) loss on risk management contracts	**(52)**	(19)	71	**19**	59
Realized (gain) loss on risk management contracts per boe[(1)]	**(1.09)**	0.28	(1.54)	**(1.32)**	0.16

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

Strathcona realized a gain on risk management contracts of $12 million for the three months ended June 30, 2026, compared to a loss of $5 million for the same period in 2025 and a gain of $16 million for the three months ended March 31, 2026. The Company realized a gain on risk management contracts of $28 million for the six months ended June 30, 2026, compared to a loss of $6 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 June 30, 2026, the mark-to-market value of risk management contracts was a net liability of $74 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.

After divesting the Montney segment in 2025, the Company’s CODMs disaggregated the Lloydminster segment into Lloydminster Thermal and Lloydminster Conventional to better reflect ongoing operations.

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 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(1)			Lloydminster Conventional Segment(1)			Corporate and Midstream			Consolidated		
	Jun 30, 2026	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026
Production volumes															
Bitumen (bbl/d)	**62,782**	56,628	61,375	**—**	—	—	**—**	—	—	**—**	—	—	**62,782**	56,628	61,375
Heavy oil (bbl/d)	**—**	—	—	**33,571**	28,281	34,597	**20,182**	23,198	20,098	**—**	—	—	**53,753**	51,479	54,695
Condensate and light oil (bbl/d)	**—**	—	—	**—**	—	—	**69**	123	78	**—**	—	—	**69**	123	78
Other NGLs (bbl/d)	**—**	—	—	**—**	—	—	**12**	44	15	**—**	—	—	**12**	44	15
Natural gas (mcf/d)	**—**	—	—	**—**	—	—	**2,436**	3,911	2,268	**—**	—	—	**2,436**	3,911	2,268
Production volumes (boe/d)	**62,782**	56,628	61,375	**33,571**	28,281	34,597	**20,669**	24,017	20,570	**—**	—	—	**117,022**	108,926	116,542
Sales volumes (boe/d)	**62,390**	56,427	61,829	**33,164**	30,692	35,649	**20,576**	24,221	20,677	**—**	—	—	**116,130**	111,340	118,155
Segment revenues															
Oil and natural gas sales	**875**	548	647	**388**	241	304	**223**	185	170	**—**	—	—	**1,486**	974	1,121
Sale of purchased products	**—**	—	2	**8**	—	—	**6**	5	—	**68**	9	2	**82**	14	4
Blending costs	**(338)**	(208)	(251)	**(43)**	(7)	(32)	**(36)**	(35)	(23)	**—**	—	—	**(417)**	(250)	(306)
Purchased product	**—**	—	(2)	**(7)**	—	—	**(5)**	(5)	—	**(68)**	(9)	(2)	**(80)**	(14)	(4)
Midstream revenue	**—**	—	—	**—**	—	—	**—**	—	—	**9**	7	9	**9**	7	9
Oil and natural gas sales, net of blending - continuing(2)	**537**	340	396	**346**	234	272	**188**	150	147	**9**	7	9	**1,080**	731	824
Segment expenses															
Royalties	**173**	62	101	**32**	15	21	**27**	19	20	**—**	—	—	**232**	96	142
Production and operating – Energy	**24**	25	35	**30**	25	33	**8**	8	9	**—**	—	—	**62**	58	77
Production and operating – Non-energy	**45**	53	44	**29**	27	30	**30**	37	29	**5**	6	5	**109**	123	108
Transportation	**23**	22	23	**64**	63	63	**9**	9	8	**—**	—	—	**96**	94	94
Field Operating Income - Continuing(2)	**272**	178	193	**191**	104	125	**114**	77	81	**4**	1	4	**581**	360	403
Depletion, depreciation and amortization	**44**	38	44	**58**	64	62	**35**	50	34	**3**	4	2	**140**	156	142
General and administrative	**9**	8	10	**9**	7	10	**8**	6	8	**—**	—	—	**26**	21	28
Finance costs	**1**	1	1	**1**	1	—	**—**	—	—	**8**	13	10	**10**	15	11
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**—**	(5)	—	**—**	(5)	—
Interest	**—**	—	—	**—**	—	—	**—**	—	—	**29**	46	28	**29**	46	28
Operating Earnings - Continuing	**218**	131	138	**123**	32	53	**71**	21	39	**(36)**	(57)	(36)	**376**	127	194
(Gain) loss on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(12)**	5	(16)	**(12)**	5	(16)
(Gain) loss on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(40)**	(24)	87	**(40)**	(24)	87
Foreign exchange loss (gain) - realized	**—**	—	—	**—**	—	—	**—**	—	—	**—**	4	(1)	**—**	4	(1)
Foreign exchange (gain) loss - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(2)**	(44)	5	**(2)**	(44)	5
Transaction related costs	**—**	—	—	**—**	—	—	**—**	—	—	**1**	14	—	**1**	14	—
Gain on marketable securities - realized	**—**	—	—	**—**	—	—	**—**	—	—	**—**	(25)	—	**—**	(25)	—
Change in decommissioning liabilities	**—**	—	—	**—**	—	—	**—**	—	—	**1**	—	13	**1**	—	13
Loss on contingent consideration	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	42	**—**	—	42
Deferred tax expense	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—	**95**	39	25
Income and comprehensive income from continuing operations													**333**	158	39
Income and comprehensive income from discontinued operations, net of tax													**—**	73	—
Income and comprehensive income													**333**	231	39

(1) Comparative period has 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.

For the Three Months Ended ($/boe)	Cold Lake Segment			Lloydminster Thermal Segment[1]			Lloydminster Conventional Segment[1]			Corporate and Midstream			Consolidated		
	Jun 30, 2026	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026	**Jun 30, 2026**	Jun 30, 2025	Mar 31, 2026
Segment revenues															
Oil and natural gas sales	**107.28**	73.28	79.56	**116.55**	84.07	85.89	**106.97**	74.44	79.76	**—**	—	—	**109.51**	75.72	81.21
Sale of purchased products	**—**	—	0.37	**2.55**	—	—	**3.00**	2.23	—	**6.47**	0.93	0.16	**7.73**	0.45	0.35
Blending costs	**(12.67)**	(7.04)	(8.34)	**(2.39)**	(0.25)	(1.03)	**(6.55)**	(6.31)	(1.16)	**—**	—	—	**(8.27)**	(4.21)	(4.58)
Purchased product	**—**	—	(0.38)	**(2.04)**	—	—	**(2.81)**	(2.27)	—	**(6.47)**	(0.93)	(0.16)	**(7.55)**	(0.44)	(0.36)
Midstream revenue	**—**	—	—	**—**	—	—	**—**	—	—	**0.82**	0.66	0.84	**0.82**	0.66	0.84
Oil and natural gas sales, net of blending - continuing[2]	**94.61**	66.24	71.21	**114.67**	83.82	84.86	**100.61**	68.09	78.60	**0.82**	0.66	0.84	**102.24**	72.18	77.46
Segment expenses															
Royalties	**30.38**	12.01	18.24	**10.82**	5.32	6.44	**14.16**	8.79	10.69	**—**	—	—	**21.92**	9.46	13.36
Production and operating – Energy	**4.39**	4.93	6.23	**10.13**	8.82	10.17	**4.29**	3.58	4.79	**0.01**	0.02	0.02	**6.03**	5.73	7.19
Production and operating – Non-energy	**7.97**	10.34	7.82	**9.41**	9.73	9.44	**15.97**	16.95	15.78	**0.52**	0.50	0.47	**10.32**	12.10	10.17
Transportation	**4.00**	4.24	4.21	**21.05**	22.73	19.59	**5.20**	4.04	4.07	**—**	—	—	**9.08**	9.30	8.82
Field Operating Netback - Continuing[2]	**47.87**	34.72	34.71	**63.26**	37.22	39.22	**60.99**	34.73	43.27	**0.29**	0.14	0.35	**54.89**	35.59	37.92
Depletion, depreciation and amortization	**7.73**	7.33	7.83	**19.29**	23.06	19.35	**18.67**	22.61	18.33	**0.25**	0.37	0.21	**13.22**	15.36	13.35
General and administrative	**1.55**	1.53	1.83	**2.83**	2.52	3.11	**4.35**	2.84	4.23	**0.02**	—	0.01	**2.43**	2.09	2.65
Finance costs	**0.12**	0.15	0.13	**0.11**	0.27	0.14	**0.01**	0.02	0.01	**0.76**	1.32	0.97	**0.86**	1.47	1.08
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(0.03)**	(0.46)	(0.02)	**(0.03)**	(0.46)	(0.02)
Interest	**—**	—	—	**—**	—	—	**—**	—	—	**2.75**	4.52	2.62	**2.75**	4.52	2.62
Operating Earnings - Continuing	**38.47**	25.71	24.92	**41.03**	11.37	16.62	**37.96**	9.26	20.70	**(3.46)**	(5.61)	(3.44)	**35.66**	12.61	18.24
Effective royalty rate (%)[2]	**32.1**	18.1	25.5	**9.4**	6.3	7.7	**14.1**	12.9	13.6	**—**	—	—	**21.4**	13.1	17.2

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(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.

For the Six Months Ended ($ millions, unless otherwise indicated)	Cold Lake Segment June 30, 2026	Cold Lake Segment June 30, 2025	Lloydminster Thermal Segment[1] June 30, 2026	Lloydminster Thermal Segment[1] June 30, 2025	Lloydminster Conventional Segment[1] June 30, 2026	Lloydminster Conventional Segment[1] June 30, 2025	Corporate and Midstream June 30, 2026	Corporate and Midstream June 30, 2025	Consolidated June 30, 2026	Consolidated June 30, 2025
Production volumes										
Bitumen (bbl/d)	**62,083**	60,799	**—**	—	**—**	—	**—**	—	**62,083**	60,799
Heavy oil (bbl/d)	**—**	—	**34,081**	27,833	**20,141**	23,153	**—**	—	**54,222**	50,986
Condensate and light oil (bbl/d)	**—**	—	**—**	—	**73**	71	**—**	—	**73**	71
Other NGLs (bbl/d)	**—**	—	**—**	—	**14**	23	**—**	—	**14**	23
Natural gas (mcf/d)	**—**	—	**—**	—	**2,352**	2,961	**—**	—	**2,352**	2,961
Production volumes (boe/d)	**62,083**	60,799	**34,081**	27,833	**20,619**	23,741	**—**	—	**116,783**	112,373
Sales volumes (boe/d)	**62,111**	60,587	**34,399**	29,351	**20,626**	23,786	**—**	—	**117,136**	113,724
Segment revenues										
Oil and natural gas sales	**1,522**	1,270	**692**	492	**393**	389	**—**	—	**2,607**	2,151
Sale of purchased product	**2**	2	**8**	—	**6**	10	**70**	9	**86**	21
Blending costs	**(589)**	(489)	**(75)**	(15)	**(59)**	(72)	**—**	—	**(723)**	(576)
Purchased product	**(2)**	(3)	**(7)**	—	**(5)**	(10)	**(70)**	(9)	**(84)**	(22)
Midstream revenue	**—**	—	**—**	—	**—**	—	**18**	7	**18**	7
Oil and natural gas sales, net of blending - continuing[2]	**933**	780	**618**	477	**335**	317	**18**	7	**1,904**	1,581
Segment expenses										
Royalties	**274**	131	**53**	33	**47**	44	**—**	—	**374**	208
Production and operating – Energy	**59**	66	**63**	49	**17**	17	**—**	—	**139**	132
Production and operating – Non-energy	**89**	107	**59**	53	**59**	67	**10**	5	**217**	232
Transportation	**46**	43	**127**	123	**17**	16	**—**	—	**190**	182
Field Operating Income - Continuing[2]	**465**	433	**316**	219	**195**	173	**8**	2	**984**	827
Depletion, depreciation and amortization	**88**	81	**120**	123	**69**	92	**5**	7	**282**	303
General and administrative	**19**	15	**19**	13	**16**	12	**—**	—	**54**	40
Finance costs	**2**	1	**1**	2	**—**	—	**18**	24	**21**	27
Other income	**—**	—	**—**	—	**—**	—	**—**	(6)	**—**	(6)
Interest	**—**	—	**—**	—	**—**	—	**57**	84	**57**	84
Operating Earnings - Continuing	**356**	336	**176**	81	**110**	69	**(72)**	(107)	**570**	379
(Gain) loss on risk management contracts - realized	**—**	—	**—**	—	**—**	—	**(28)**	6	**(28)**	6
Loss on risk management contracts - unrealized	**—**	—	**—**	—	**—**	—	**47**	53	**47**	53
Foreign exchange (gain) loss - realized	**—**	—	**—**	—	**—**	—	**(1)**	4	**(1)**	4
Foreign exchange loss (gain) - unrealized	**—**	—	**—**	—	**—**	—	**3**	(45)	**3**	(45)
Transaction related costs	**—**	—	**—**	—	**—**	—	**1**	15	**1**	15
Gain on marketable securities - realized	**—**	—	**—**	—	**—**	—	**—**	(47)	**—**	(47)
Change in decommissioning liabilities	**—**	—	**—**	—	**—**	—	**14**	—	**14**	—
Loss on contingent consideration	**—**	—	**—**	—	**—**	—	**42**	—	**42**	—
Deferred tax expense	**—**	—	**—**	—	**—**	—	**—**	—	**120**	82
Income and comprehensive income from continuing operations									**372**	311
Income and comprehensive income from discontinued operations, net of tax									**—**	125
Income and comprehensive income									**372**	**436**

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(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.

For the Six Months Ended ($/boe)	Cold Lake Segment		Lloydminster Thermal Segment[1]		Lloydminster Conventional Segment[1]		Corporate and Midstream		Consolidated	
	June 30, 2026	June 30, 2025	**June 30, 2026**	June 30, 2025	**June 30, 2026**	June 30, 2025	**June 30, 2026**	June 30, 2025	**June 30, 2026**	June 30, 2025
Segment revenues										
Oil and natural gas sales	**93.42**	79.09	**100.75**	89.96	**93.26**	79.48	**—**	—	**95.25**	81.31
Sale of purchased products	**0.19**	0.22	**1.24**	—	**1.51**	2.28	**3.30**	0.46	**4.03**	1.05
Blending costs	**(10.40)**	(7.89)	**(1.69)**	(0.19)	**(3.71)**	(5.89)	**—**	—	**(6.36)**	(4.79)
Purchased product	**(0.19)**	(0.24)	**(0.99)**	—	**(1.41)**	(2.30)	**(3.30)**	(0.46)	**(3.94)**	(1.07)
Midstream revenue	**—**	—	**—**	—	**—**	—	**0.83**	0.32	**0.83**	0.32
Oil and natural gas sales, net of blending - continuing[2]	**83.02**	71.18	**99.31**	89.77	**89.65**	73.57	**0.83**	0.32	**89.81**	76.82
Segment expenses										
Royalties	**24.37**	11.95	**8.56**	6.25	**12.43**	10.24	**—**	—	**17.63**	10.12
Production and operating – Energy	**5.30**	6.00	**10.15**	9.18	**4.54**	4.00	**0.02**	0.01	**6.61**	6.41
Production and operating – Non-energy	**7.89**	9.74	**9.42**	9.79	**15.88**	15.68	**0.50**	0.25	**10.25**	11.24
Transportation	**4.10**	3.92	**20.30**	23.25	**4.64**	3.64	**—**	—	**8.95**	8.85
Field Operating Netback - Continuing[2]	**41.36**	39.57	**50.88**	41.30	**52.16**	40.01	**0.31**	0.06	**46.37**	40.20
Depletion, depreciation and amortization	**7.78**	7.37	**19.32**	23.09	**18.50**	21.41	**0.23**	0.37	**13.29**	14.73
General and administrative	**1.69**	1.37	**2.97**	2.52	**4.29**	2.77	**0.01**	—	**2.54**	1.96
Finance costs	**0.13**	0.14	**0.13**	0.31	**0.01**	0.02	**0.86**	1.17	**0.97**	1.32
Other income	**—**	—	**—**	—	**—**	—	**(0.02)**	(0.30)	**(0.02)**	(0.30)
Interest	**—**	—	**—**	—	**—**	—	**2.68**	4.09	**2.68**	4.09
Operating Earnings - Continuing	**31.76**	30.69	**28.46**	15.38	**29.36**	15.81	**(3.45)**	(5.27)	**26.91**	18.40
Effective royalty rate (%)[2]	**29.4**	16.8	**8.6**	7.0	**13.9**	13.9	**—**	—	**19.6**	13.2

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Cold Lake Segment

Production at the Cold Lake segment for the three months ended June 30, 2026 increased to 62,782 boe per day compared to 56,628 boe per day in the same period of 2025. This increase was primarily due to production gains at Tucker. For the six months ended June 30, 2026, production increased to 62,083 boe per day, compared to 60,799 boe per day in the same period of 2025. This increase was primarily due to pump failures and restrictions at natural gas transportation systems at Orion in the comparable period of 2025 and production gains at Lindbergh in the current quarter.

Oil and natural gas sales, net of blending, increased to $537 million ($94.61 per boe) during the three months ended June 30, 2026 compared to $340 million ($66.24 per boe) for the same period of 2025. During the six months ended June 30, 2026, oil and natural gas sales, net of blending, increased to $933 million ($83.02 per boe) compared to $780 million ($71.18 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 six months ended June 30, 2026 increased to 32.1% and 29.4%, respectively, from 18.1% and 16.8%, 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 June 30, 2026 decreased to $24 million ($4.39 per boe) from $25 million ($4.93 per boe) in the same period in 2025. During the six months ended June 30, 2026 energy related production and operating expenses decreased to $59 million ($5.30 per boe) from $66 million ($6.00 per boe) in the same period of 2025. These decreases were primarily attributable to a decrease in fuel costs due to lower natural gas benchmark prices, partially offset by an increase in carbon tax expense as the result of the purchase of carbon credits, which reduced the Company's carbon tax obligation relative to legislated rates, in the comparable period of 2025.

Non-energy related production and operating expenses for the three months ended June 30, 2026 decreased to $45 million ($7.97 per boe) from $53 million ($10.34 per boe) in the same period in 2025. This decrease was primarily due decreased downhole maintenance and chemical costs. During the six months ended June 30, 2026, non-energy related production and operating expenses decreased to $89 million ($7.89 per boe) from $107 million ($9.74 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 and downhole maintenance.

For the three months ended June 30, 2026, transportation expenses increased to $23 million ($4.00 per boe) compared to $22 million ($4.24 per boe) in the same period of 2025. This increase was primarily attributable to higher sales volumes at Lindbergh and Orion, and the timing and utilization of make-up rights. For the six months ended June 30, 2026, transportation expenses increased to $46 million ($4.10 per boe) from $43 million ($3.92 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 six months ended June 30, 2026 increased to $44 million ($7.73 per boe) and $88 million ($7.78 per boe), respectively, compared to $38 million ($7.33 per boe) and $81 million ($7.37 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 June 30, 2026 increased to $9 million ($1.55 per boe) compared to $8 million ($1.53 per boe) in the same period of 2025. General and administrative for the six months ended June 30, 2026 increased to $19 million ($1.69 per boe) compared to $15 million ($1.37 per boe) in the same period of 2025. These increases were primarily due 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 June 30, 2026, increased to 33,571 boe per day compared to 28,281 boe per day in the same period of 2025. For the six months ended June 30, 2026, production increased to 34,081 boe per day, compared to 27,833 boe per day in the same period of 2025. These increases were due to the Vawn Acquisition.

Oil and natural gas sales, net of blending, increased to $346 million ($114.67 per boe) during the three months ended June 30, 2026 compared to $234 million ($83.82 per boe) for the same period of 2025. For the six months ended June 30, 2026, oil and natural gas sales, net of blending, increased to $618 million ($99.31 per boe) compared to $477 million ($89.77 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.

The effective royalty rate for the three and six months ended June 30, 2026 increased to 9.4% and 8.6%, respectively, compared to 6.3% and 7.0% 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 June 30, 2026 increased to $30 million ($10.13 per boe) compared to $25 million ($8.82 per boe) for the same period in 2025. Energy related production and operating expenses for the six months ended June 30, 2026 increased to $63 million ($10.15 per boe) compared to $49 million ($9.18 per boe) for the same period in 2025. These increases were primarily due to higher carbon tax expense as the result of the Company utilizing internally generated carbon credits, which reduced its carbon tax obligation relative to legislated rates, in the comparable period of 2025, and higher fuel costs as a result of the Vawn Acquisition.

Non-energy related production and operating expenses for the three months ended June 30, 2026 increased to $29 million ($9.41 per boe) compared to $27 million ($9.73 per boe) in the same period of 2025. Non-energy related production and operating expenses for the six months ended June 30, 2026 increased to $59 million ($9.42 per boe), compared to $53 million ($9.79 per boe) for the same period in 2025. These increases were primarily due to higher operating costs as the result of the Vawn Acquisition, and higher downhole maintenance and sand handling expenses.

For the three months ended June 30, 2026, transportation expenses increased to $64 million ($21.05 per boe) compared to $63 million ($22.73 per boe) in the same period of 2025. This increase is primarily due to $2 million in costs associated with the Vawn Acquisition and higher sales volumes. For the six months ended June 30, 2026, transportation expenses increased to $127 million ($20.30 per boe) from $123 million ($23.25 per boe) in the same period of 2025. This increase is primarily due to $4 million in costs associated with the Vawn Acquisition and higher sales volumes. Despite the increases in absolute costs, the decreases on a per boe basis for the three and six months ended June 30, 2026 reflects that the majority of the incremental costs relate to Vawn volumes, which are transported by pipeline and therefore incur lower per barrel transportation costs.

Depletion, depreciation and amortization for the three and six months ended June 30, 2026 decreased to $58 million ($19.29 per boe) and $120 million ($19.32 per boe), respectively, compared to $64 million ($23.06 per boe) and $123 million ($23.09 per boe), in the same periods of 2025. These decreases were due to a higher proportion of sales volumes in areas with lower depletion rates.

General and administrative for the three months ended June 30, 2026 increased to $9 million ($2.83 per boe) compared to $7 million ($2.52 per boe) in the same period of 2025. General and administrative for the six months ended June 30, 2026 increased to $19 million ($2.97 per boe) compared to $13 million ($2.52 per boe) in the same period of 2025. These increases were primarily due 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 June 30, 2026, decreased to 20,669 boe per day compared to 24,017 boe per day in the same period of 2025. For the six months ended June 30, 2026, production decreased to 20,619 boe per day, compared to 23,741 boe per day in the same period of 2025. These decreases were primarily attributable to development challenges and a turnaround at Winter.

Oil and natural gas sales, net of blending, increased to $188 million ($100.61 per boe) during the three months ended June 30, 2026 compared to $150 million ($68.09 per boe) for the same period of 2025. Oil and natural gas sales, net of blending, increased to $335 million ($89.65 per boe) during the six months ended June 30, 2026 compared to $317 million ($73.57 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 decreased sales volumes.

The effective royalty rate for the three and six months ended June 30, 2026 increased to 14.1% and 13.9%, respectively, compared to 12.9% and 13.9%, 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 June 30, 2026 remained consistent at $8 million ($4.29 per boe) compared to $8 million ($3.58 per boe) for the same period in 2025. During the six months ended June 30, 2026 energy related production and operating expenses remained consistent at $17 million ($4.54 per boe) from $17 million ($4.00 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 June 30, 2026 decreased to $30 million ($15.97 per boe) compared to $37 million ($16.95 per boe) in the same period of 2025. Non-energy related production and operating expenses for the six months ended June 30, 2026 decreased to $59 million ($15.88 per boe) compared to $67 million ($15.68 per boe) for the same period in 2025. These decreases were primarily attributable to a decrease in downhole and surface maintenance, and lower chemical costs as the result of improved H_2S scavenger rates and volumes.

For the three months ended June 30, 2026, transportation expenses remained consistent at $9 million ($5.20 per boe) compared to $9 million ($4.04 per boe) in the same period of 2025. For the six months ended June 30, 2026, transportation expenses increased to $17 million ($4.64 per boe) from $16 million ($3.64 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 six months ended June 30, 2026 decreased to $35 million ($18.67 per boe) and $69 million ($18.50 per boe), respectively, compared to $50 million ($22.61 per boe) and $92 million ($21.41 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 June 30, 2026 increased to $8 million ($4.35 per boe) compared to $6 million ($2.84 per boe) in the same period of 2025. General and administrative for the six months ended June 30, 2026 increased to $16 million ($4.29 per boe) compared to $12 million ($2.77 per boe) in the same period of 2025. These increases were primarily due to the reallocation of corporate costs across the business following the sale of the Montney segment.

Midstream

Midstream revenue for the three and six months ended June 30, 2026 was $9 million ($0.82 per boe) and $18 million ($0.83 per boe), respectively, compared to $7 million ($0.66 per boe) and $7 million ($0.32 per boe) in the same periods of 2025. Non-energy related production and operating expenses associated with midstream operations, for the three and six months ended June 30, 2026, were $5 million ($0.52 per boe) and $10 million ($0.50 per boe), respectively, compared to $6 million ($0.50 per boe) and $5 million ($0.25 per boe) in the same periods of 2025.

CAPITAL RESOURCES

Bank Credit Facilities

Covenant-Based Revolving Credit Facility and Term Credit Facility

On June 5, 2026, the Company exercised the $265 million accordion feature under the agreement governing its covenant-based credit facilities (the "**Credit Agreement**"), increasing the capacity of the covenant-based revolving credit facility (the "**Revolving Credit Facility**") to $3.51 billion at June 30, 2026 (December 31, 2025 - $3.24 billion). At June 30, 2026, the Company also had 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**"). The Credit Facilities are with a syndicate of Canadian, U.S. and international financial institutions.

At June 30, 2026, the Credit Facilities had a maturity date of March 28, 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, CORRA or Secured Overnight Financing Rate 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.

On July 30, 2026, certain amendments were made to the Credit Facilities, including an extension of the maturity date to December 31, 2030 and a reset and increase in the amount of the accordion feature to $750 million.

At June 30, 2026, the Company had letters of credit outstanding under the Revolving Credit Facility of $2 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 June 30, 2026 the cross-currency swap asset was $22 million (December 31, 2025 – a liability of $5 million) and total debt includes an unrealized loss of $22 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 June 30, 2026, the Company had the following cross-currency interest rate swap contracts outstanding:

Notional (US$)	Maturity Date	Contract Price
1,127 million	July 22, 2026	CAD/USD 1.4000
175 million	July 29, 2026	CAD/USD 1.4229

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 noncash 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 June 30, 2026, the Company was in compliance with such financial covenants.

Demand Letter of Credit Facility

As at June 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 June 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	**June 30, 2026**	December 31, 2025
Revolving Credit Facility capacity	**3,505**	3,240
Term Credit Facility capacity[1]	**248**	240
Credit Facilities capacity	**3,753**	3,480
Credit Facilities debt[1]	**(1,967)**	(2,116)
Unrealized loss (gain) on U.S. borrowings	**22**	(5)
Letters of credit outstanding	**(2)**	(2)
Availability	**1,806**	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 June 30, 2026, the working capital deficiency was $448 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 June 30, 2026.

	Total	**<1 year**	**1-3 years**	**4-5 years**	**> 5 years**
Credit Facilities[1]	**1,945**	—	—	1,945	—
Accounts payable and accrued liabilities	**730**	730	—	—	—
Risk management contract liability	**111**	24	87	—	—
Lease obligations[2]	**81**	25	21	10	25
Contingent consideration	**33**	33	—	—	—
Total	**2,900**	812	108	1,955	25

(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 June 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	**2,609**	168	341	371	1,729
Capital	**183**	167	13	—	3
Other	**58**	16	41	1	—
Total	**2,850**	351	395	372	1,732

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 June 30, 2026 (December 31, 2025 – $nil).

The following table summarizes the number of shares outstanding as at August 5, 2026:

Share Class	Shares Outstanding at August 5, 2026
Common shares	214,235,608

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%.

Dividends

During the three and six months ended June 30, 2026, Strathcona declared and paid dividends of $64 million ($0.30 per common share) and $128 million ($0.60 per common share), respectively ($64 million ($0.30 per common share) and $120 million ($0.56 per common share) for the three and six months ended June 30, 2025) .

On August 5, 2026, the Strathcona Board of Directors declared a quarterly dividend of $0.30 per common share to be paid on September 21, 2026 to all shareholders of record on September 11, 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 six months ended June 30, 2026, no common shares were repurchased under the NCIB.

SUMMARY OF QUARTERLY RESULTS

	2026		2025				2024[1]	
($ millions, unless otherwise indicated)	**Q2**	Q1	Q4	Q3	Q2	Q1[1]	Q4	Q3
Operating results (boe/d)								
Average production volumes	**117,022**	116,542	117,715	116,201	181,368	194,609	187,203	178,235
Continuing operations	**117,022**	116,542	117,679	115,584	108,926	115,859	111,013	109,328
Discontinued operations	**—**	—	36	617	72,442	78,750	76,190	68,907
Financial Results								
Oil and natural gas sales	**1,486**	1,121	937	1,012	1,209	1,459	1,293	1,272
Continuing operations	**1,486**	1,121	937	1,009	974	1,176	1,043	1,059
Discontinued operations	**—**	—	—	3	235	283	250	213
Net income (loss)	**333**	39	(99)	573	231	206	88	188
Continuing operations	**333**	39	(90)	144	158	153	50	184
Discontinued operations	**—**	—	(9)	429	73	53	38	4
Net income (loss) per share	**1.55**	0.18	(0.47)	2.68	1.08	0.96	0.41	0.88
Continuing operations	**1.55**	0.18	(0.42)	0.68	0.74	0.71	0.23	0.86
Discontinued operations	**—**	—	(0.05)	2.00	0.34	0.25	0.18	0.02
Operating Earnings	**376**	194	146	236	225	322	190	265
Continuing operations	**376**	194	138	227	127	251	137	253
Discontinued operations[2]	**—**	—	8	9	98	71	53	12
Free Cash Flow[2]	**296**	47	53	94	32	185	(1)	201
Continuing operations[2]	**296**	47	33	85	43	169	1	105
Discontinued operations[2]	**—**	—	20	9	(11)	16	(2)	96
Capital expenditures[3]	**233**	298	176	281	379	350	393	320
Decommissioning expenditures[3]	**9**	19	9	8	3	23	13	9

(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) 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.

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 **June 30, 2026**	 June 30, 2025	 March 31, 2026	Six Months Ended **June 30, 2026**	 June 30, 2025
Operating Earnings - Continuing	**376**	127	194	**570**	379
Depletion, depreciation and amortization	**140**	156	142	**282**	303
Finance costs	**10**	15	11	**21**	27
Gain (loss) on risk management contracts - realized	**12**	(5)	16	**28**	(6)
Foreign exchange gain (loss) - realized	**—**	(4)	1	**1**	(4)
Funds from Operations - Continuing	**538**	289	364	**902**	699
Capital expenditures	**(233)**	(245)	(298)	**(531)**	(479)
Decommissioning costs	**(9)**	(1)	(19)	**(28)**	(9)
Free Cash Flow - Continuing	**296**	43	47	**343**	211

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2026**	 June 30, 2025	 March 31, 2026	Six Months Ended **June 30, 2026**	 June 30, 2025
Operating Earnings - Discontinued	**—**	98	—	**—**	169
Depletion, depreciation and amortization	**—**	22	—	**—**	90
Finance costs	**—**	5	—	**—**	13
Funds from Operations - Discontinued	**—**	125	—	**—**	272
Capital expenditures	**—**	(134)	—	**—**	(250)
Decommissioning costs	**—**	(2)	—	**—**	(18)
Free Cash Flow - Discontinued	**—**	(11)	—	**—**	4

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 **June 30, 2026**	 June 30, 2025	 March 31, 2026	Six Months Ended **June 30, 2026**	 June 30, 2025
Operating Earnings	**376**	225	194	**570**	548
Depletion, depreciation and amortization	**140**	178	142	**282**	393
Finance costs	**10**	20	11	**21**	40
Gain (loss) on risk management contracts - realized	**12**	(5)	16	**28**	(6)
Foreign exchange gain (loss) - realized	**—**	(4)	1	**1**	(4)
Funds from Operations	**538**	414	364	**902**	971
Capital expenditures	**(233)**	(379)	(298)	**(531)**	(729)
Decommissioning costs	**(9)**	(3)	(19)	**(28)**	(27)
Free Cash Flow	**296**	32	47	**343**	215

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 June 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 June 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 six 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			Six Months Ended	
	June 30, 2026	June 30, 2025[1]	March 31, 2026	**June 30, 2026**	June 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)	**62,782**	56,628	61,375	**62,083**	60,799
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**62,782**	56,628	61,375	**62,083**	60,799
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**62,782**	56,628	61,375	**62,083**	60,799
Lloydminster Thermal segment[1]					
Heavy crude oil (bbl/d)	**33,571**	28,281	34,597	**34,081**	27,833
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**33,571**	28,281	34,597	**34,081**	27,833
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**33,571**	28,281	34,597	**34,081**	27,833
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**33,571**	28,281	34,597	**34,081**	27,833
Lloydminster Conventional segment[1]					
Heavy crude oil (bbl/d)	**20,182**	23,198	20,098	**20,141**	23,153
Light and medium crude oil (bbl/d)	**56**	121	69	**63**	69
Total crude oil (bbl/d)	**20,238**	23,319	20,167	**20,204**	23,222
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**25**	46	24	**24**	25
Total liquids (bbl/d)	**20,263**	23,365	20,191	**20,228**	23,247
Conventional natural gas (mcf/d)	**2,436**	3,911	2,268	**2,352**	2,961
Total (boe/d)	**20,669**	24,017	20,570	**20,619**	23,741
Discontinued operations					
Heavy crude oil (bbl/d)	**—**	49	—	**—**	25
Light and medium crude oil (bbl/d)	**—**	302	—	**—**	394
Total crude oil (bbl/d)	**—**	351	—	**—**	419
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**—**	32,480	—	**—**	32,247
Total liquids (bbl/d)	**—**	32,831	—	**—**	32,666
Conventional natural gas (mcf/d)	**—**	237,668	—	**—**	257,482
Total (boe/d)	**—**	72,442	—	**—**	75,579

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

	Three Months Ended			Six Months Ended	
	June 30, 2026	June 30, 2025(1)	March 31, 2026	**June 30, 2026**	June 30, 2025(1)
Consolidated					
Heavy crude oil (bbl/d)	**53,753**	51,528	54,695	**54,222**	51,011
Light and medium crude oil (bbl/d)	**56**	423	69	**63**	463
Total crude oil (bbl/d)	**53,809**	51,951	54,764	**54,285**	51,474
Bitumen (bbl/d)	**62,782**	56,628	61,375	**62,083**	60,799
NGLs (bbl/d)	**25**	32,526	24	**24**	32,272
Total liquids (bbl/d)	**116,616**	141,105	116,163	**116,392**	144,545
Conventional natural gas (mcf/d)	**2,436**	241,579	2,268	**2,352**	260,443
Total (boe/d)	**117,022**	181,368	116,542	**116,783**	187,952

(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 2026 production and capital spending guidance; 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 Company's ability to meet current and future obligations, including making scheduled principal and interest payments, to fund planned capital expenditures and to fund the other needs of the business; future liquidity and financial capacity; anticipated proceeds from financial instruments, including commodity contracts; and sources of funding for the Company's capital program, 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: 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 the closure of 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; 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 purpose of the capital expenditure guidance is to assist readers in understanding Strathcona's expected and targeted financial position and performance, and this information may not be appropriate for other purposes.

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

ADDITIONAL INFORMATION

Additional information about Strathcona, including Strathcona's annual information form for the year ended December 31, 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.