



SECOND QUARTER REPORT

THREE AND SIX MONTHS ENDED JUNE 30, 2026

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED 2026 SECOND QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's second quarter results, "We had a very strong 2026 second quarter, reflecting our continued focus on operational excellence, capital efficiency and continuous improvement, which drove eight new operational and financial records in the quarter. An example of this performance was achieved in our world class Oil Sands Mining and Upgrading operations, where we experienced challenging weather elements, like other oil sands operations; however, our team successfully managed these challenges allowing the Company to exceed our budgeted production levels in the quarter, resulting in the highest quarterly oil sands mining production in its history, averaging approximately 625,000 bbl/d in Q2/26, with high upgrader utilization of 106%. These world class assets provide high-value Synthetic Crude Oil ("SCO"), which captured robust pricing in Q2/26, with the SCO premium to WTI averaging US\$8.37/bbl in the quarter, and when combined with industry leading low operating costs of \$22.19/bbl (US\$16.03/bbl), resulted in the highest Oil Sands Mining and Upgrading per barrel netback ever achieved by the Company, during a quarter, at approximately \$78.00/bbl.

On a total corporate basis, we achieved record quarterly production of approximately 1,677,000 BOE/d in Q2/26, resulting in year-over-year growth of approximately 256,000 BOE/d or 18% from Q2/25 levels. Total quarterly liquids production was also a record at approximately 1,249,000 bbl/d, of which 67% was high-value SCO, light crude oil and NGLs. We also achieved record quarterly liquids production of approximately 338,000 bbl/d in our North American Conventional E&P assets, representing an increase of 67,000 bbl/d or 25% from Q2/25 levels.

Following the completion of a strategic acquisition in Q2/26 and strong conventional drilling results year to date, we are increasing our 2026 annual production guidance range for the second time this year to 1,637 MBOE/d and 1,682 MBOE/d, a 20 MBOE/d increase at mid-point from the previous guidance range of 1,615 MBOE/d and 1,665 MBOE/d. We remain focused on executing our prudent and efficient 2026 capital program as our operating capital remains unchanged at approximately \$6.0 billion, before net acquisition costs. Our ability to effectively allocate capital across our large and diverse asset base provides us with a unique competitive advantage and, when combined with accretive acquisitions, continues to create significant long-term value for our shareholders.

The recent trilateral Memorandum of Understanding ("MOU") between the Oil Sands Alliance, the Government of Alberta and the Federal government establishes a positive first step for future economic production growth in Canada, when associated with additional egress opportunities and a clear pathway to reduce Greenhouse Gas ("GHG") emissions. We look forward to working with both levels of government on the definitive agreements targeted for completion this fall, which will provide clarity on assessing our potential medium and long-term growth projects."

Canadian Natural's Chief Financial Officer, Victor Darel, added "Along with strong operational performance, we delivered impressive financial performance in Q2/26, generating quarterly results that were the highest in the Company's history for both adjusted net earnings of \$4.6 billion, or \$2.20 per share, and adjusted funds flow of \$6.9 billion, or \$3.30 per share. This robust cash flow generation provided significant returns to shareholders, totaling approximately \$4.0 billion in Q2/26, including direct returns of \$2.4 billion, comprised of \$1.3 billion in dividends and \$1.1 billion in share repurchases, and indirect returns of \$1.6 billion through net debt reduction, enhancing long-term shareholder value.

Our leading dividend continues as the Board of Directors has declared a quarterly dividend on our common shares of \$0.625 or \$2.50 when annualized. The year 2026 is our 26th consecutive year of dividend increases, following the increase announced earlier this year, and demonstrates the strength and resilience of our business model, the quality and longevity of our asset base, and our robust balance sheet.

Supported by the current commodity price environment and the continued excellence of our safe, effective and efficient operations, we are generating significant free cash flow while advancing our strategic priorities. Our financial strength allows us to deliver substantial returns to shareholders, accelerate net debt reduction, and move more quickly toward our next targeted net debt level of \$13 billion. Achieving this milestone will position us to increase shareholder returns to 100% of free cash flow, further enhancing value for our shareholders."

SECOND QUARTER HIGHLIGHTS

- Generated quarterly net earnings of approximately \$4.5 billion and record quarterly adjusted net earnings from operations of \$4.6 billion.
- Generated record quarterly adjusted funds flow of approximately \$6.9 billion.
 - Captured strong SCO pricing that averaged a US\$8.37/bbl premium to WTI.
 - Canadian Natural produces a significant amount of sulphur, representing approximately 30% of Canada's sulphur supply and 2% of the world's sulphur supply. With strong sulphur pricing in 2026, the Company generated in Q2/26 net revenue from sulphur sales⁽¹⁾ of approximately \$270 million, and a combined \$450 million in the first two quarters of 2026.
- Returns to shareholders totaled approximately \$4.0 billion in the quarter.
 - Direct returns to shareholders totaled approximately \$2.4 billion, comprised of \$1.3 billion in dividends and \$1.1 billion in share repurchases.
 - Year to date, up to and including August 5, 2026, the Company has returned a total of approximately \$5.7 billion directly to shareholders through \$3.8 billion in dividends and \$1.9 billion in share repurchases.
 - Subsequent to quarter end, the Company declared a quarterly cash dividend on its common shares of \$0.625 per common share.
 - Indirect returns to shareholders, through net debt reductions, totaled approximately \$1.6 billion as the Company reduced its net debt to \$14.5 billion at June 30, 2026.
- Record total quarterly production of approximately 1,677,000 BOE/d, an increase of 256,000 BOE/d or 18% from Q2/25 levels.
 - Record quarterly liquids production of approximately 1,249,000 bbl/d, an increase of 230,000 bbl/d or 23% from Q2/25 levels.
 - Record quarterly Jackfish thermal in situ production of approximately 136,000 bbl/d, exceeding facility nameplate capacity of 120,000 bbl/d.
 - The two new Steam Assisted Gravity Drainage ("SAGD") pads at Pike 1 continue to exceed expectations, with current combined production of approximately 46,000 bbl/d and a Steam to Oil Ratio ("SOR") of 1.8x.
 - Record quarterly Oil Sands Mining and Upgrading SCO production of approximately 625,000 bbl/d with strong upgrader utilization of 106%.
 - Industry leading operating costs of \$22.19/bbl (US\$16.03/bbl), driving our highest Oil Sands Mining and Upgrading per barrel netback ever achieved by the Company, during a quarter, at approximately \$78.00/bbl.
 - Record North American Conventional E&P liquids production of approximately 338,000 bbl/d, an increase of 67,000 bbl/d or 25% from Q2/25 levels.

(1) Item is a component of 'Other income and revenue' in Note 17 Segmented Information in the Company's consolidated financial statements.

UPDATED 2026 GUIDANCE

- In Q2/26, Canadian Natural acquired additional assets in the Peace River area of Alberta, which are adjacent to existing operations, for approximately \$761 million, net of closing adjustments.
- 2026 total forecasted operating capital expenditures remain unchanged, with forecasted total annual capital expenditures now reflecting the recent acquisition.

2026 Capital Expenditures⁽¹⁾ (\$ millions)	March Forecast	Updated August Forecast	Change
Conventional E&P	\$ 3,160	\$ 3,160	\$ —
Thermal and Oil Sands Mining & Upgrading	\$ 2,830	\$ 2,830	\$ —
Total Operating Capital Expenditures	\$ 5,990	\$ 5,990	\$ —
Carbon Capture	\$ 125	\$ 125	\$ —
Net acquisitions	\$ 765	\$ 1,526	\$ 761
Total Capital Expenditures	\$ 6,880	\$ 7,641	\$ 761

(1) Forward-looking Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

Note: 2026 capital expenditures excludes approximately \$993 million of abandonment expenditures, before recoveries, related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea.

- As a result of the acquisition and strong conventional drilling results, the 2026 annual production guidance range is being increased for the second time this year to 1,637 MBOE/d and 1,682 MBOE/d, with the mid-point being 20 MBOE/d higher than the previous guidance.

2026 Production Guidance⁽¹⁾ (before royalties)	March Forecast	Updated August Forecast
Natural Gas (MMcf/d)	2,560 - 2,615	2,595 - 2,635
Conventional E&P Crude Oil & NGLs (Mbbbl/d)	336 - 346	352 - 360
Thermal and Oil Sands Mining & Upgrading (Mbbbl/d)	852 - 883	852 - 883
Total Liquids (Mbbbl/d)	1,188 - 1,229	1,204 - 1,243
Total MBOE/d	1,615 - 1,665	1,637 - 1,682

(1) Reflects planned downtime for turnaround activities in all areas and is rounded to the nearest 1,000 bbl/d.

TRILATERAL MOU UPDATE & GROWTH POTENTIAL

- The recent trilateral MOU between the Oil Sands Alliance, the Government of Alberta and the Federal government establishes a positive first step for future economic production growth in Canada, when associated with additional egress opportunities and a clear pathway to reduce GHG emissions. The trilateral MOU outlines a potential regulatory and fiscal framework intended to support the competitiveness of Canada's energy industry. Until definitive agreements are finalized, targeted in November 2026, development of Canadian Natural's medium and long-term growth projects remain on hold. The projects which remain on hold are:
 - The Company's medium-term growth opportunities consisting of the 30,000 bbl/d Jackfish project and the 70,000 bbl/d Pike 2 project.
 - The Company's long-term growth opportunities which are focused in its Oil Sands Mining and Upgrading assets, include adding 150,000 bbl/d at a new Jackpine Mine at Albion and a new 90,000 bbl/d In-Pit Extraction Plant and Paraffinic Froth Treatment at Horizon.

HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Net earnings	\$ 4,503	\$ 1,348	\$ 2,459	\$ 5,851	\$ 4,917
Per common share – basic	\$ 2.17	\$ 0.65	\$ 1.17	\$ 2.81	\$ 2.34
– diluted	\$ 2.15	\$ 0.64	\$ 1.17	\$ 2.80	\$ 2.34
Adjusted net earnings from operations ⁽¹⁾	\$ 4,568	\$ 2,446	\$ 1,496	\$ 7,014	\$ 3,932
Per common share – basic ⁽²⁾	\$ 2.20	\$ 1.17	\$ 0.71	\$ 3.37	\$ 1.88
– diluted ⁽²⁾	\$ 2.19	\$ 1.17	\$ 0.71	\$ 3.35	\$ 1.87
Cash flows from operating activities	\$ 6,823	\$ 3,282	\$ 3,114	\$ 10,105	\$ 7,398
Adjusted funds flow ⁽¹⁾	\$ 6,866	\$ 4,374	\$ 3,262	\$ 11,240	\$ 7,792
Per common share – basic ⁽²⁾	\$ 3.30	\$ 2.10	\$ 1.56	\$ 5.40	\$ 3.72
– diluted ⁽²⁾	\$ 3.28	\$ 2.09	\$ 1.55	\$ 5.37	\$ 3.70
Cash flows used in investing activities	\$ 2,468	\$ 1,949	\$ 1,941	\$ 4,417	\$ 3,253
Net capital expenditures ⁽¹⁾	\$ 2,405	\$ 2,028	\$ 1,915	\$ 4,433	\$ 3,218
Net capital expenditures ⁽¹⁾ , excluding net acquisitions	\$ 1,643	\$ 1,255	\$ 1,691	\$ 2,898	\$ 2,994
Abandonment expenditures	\$ 182	\$ 247	\$ 193	\$ 429	\$ 381
Daily production, before royalties					
Natural gas (MMcf/d)	2,567	2,670	2,407	2,619	2,429
Crude oil and NGLs (bbl/d)	1,248,889	1,198,079	1,019,149	1,223,625	1,096,049
Equivalent production (BOE/d) ⁽³⁾	1,676,754	1,643,160	1,420,358	1,660,050	1,500,905

(1) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

(2) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, or to compare the value ratio using current crude oil and natural gas prices since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

SHAREHOLDER RETURNS

- Year to date, up to and including August 5, 2026, the Company has returned a total of approximately \$5.7 billion directly to shareholders through \$3.8 billion in dividends and \$1.9 billion through the repurchase and cancellation of approximately 30.7 million common shares at a weighted average price of \$61.49 per share.
- On August 5, 2026, the Board of Directors approved a quarterly cash dividend of \$0.625 per common share, payable on October 2, 2026 to shareholders of record at the close of business on September 11, 2026.
 - This dividend represents an annualized dividend of \$2.50 per common share which has grown for 26 consecutive years, demonstrating the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.

CORPORATE UPDATE

Canadian Natural is pleased to welcome Dr. G.E. Isaac to the Board of Directors of the Company, following his election at the May 7, 2026 Annual General Meeting. Dr. Isaac is currently the President and Chief Operating Officer of Cameco Corporation. Prior to his appointment as President and COO of Cameco in 2025, he held various executive roles with Cameco, including Executive Vice President and CFO as well as Senior Vice-President, Corporate Services. He has also served on various boards including the University of Saskatchewan Board of Governors and as Chair of the Board of Directors of the Canadian Nuclear Association. Dr. Isaac received a Bachelor of Arts (Economics) and a Master of Arts (Economics) from the University of Saskatchewan and a Ph.D. from the London School of Economics.

OPERATIONS REVIEW

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Synthetic crude oil production (bbl/d) ⁽¹⁾⁽²⁾	624,754	587,946	463,808	606,452	529,099

(1) SCO production before royalties and excludes production volumes consumed internally as diesel.

(2) Consists of heavy and light synthetic crude oil products.

- Record quarterly Oil Sands Mining and Upgrading production was achieved in Q2/26, averaging 624,754 bbl/d of SCO with a high upgrader utilization of 106% as a result of effective and efficient operations. Production in Q2/26 represents an increase of approximately 161,000 bbl/d or 35% compared to Q2/25 levels, reflecting strong operations, the additional working interest in the AOSP mines acquired in Q4/25 and the turnaround at AOSP completed in Q2/25.
 - Oil Sands Mining and Upgrading operating costs are industry leading, averaging \$22.19/bbl (US\$16.03/bbl) of SCO in Q2/26, representing a decrease of 16% from Q2/25, primarily due to higher production.
- At Horizon, a planned 35 day turnaround is scheduled to begin on September 8, 2026, and is targeted to impact annual average production by approximately 29,000 bbl/d, which is included in the Company's annual production guidance.
- The Company's Naphtha Recovery Unit Tailings Treatment ("NRUTT") project at Horizon remains on track with capital on budget and targeted incremental production of approximately 6,300 bbl/d of SCO, following mechanical completion in Q3/27.

North America Exploration and Production

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Bitumen production (bbl/d)	275,607	274,674	274,789	275,143	279,721
Net bitumen wells drilled	38	31	24	69	42
Net successful bitumen wells drilled	38	30	24	68	42
Success rate	100%	97%	100%	99%	100%

- Thermal in situ production averaged 275,607 bbl/d in Q2/26, comparable to Q2/25 levels, reflecting recent SAGD pad additions, offset by timing of steam cycles at Primrose and natural field declines.
 - Jackfish achieved record quarterly production of 136,381 bbl/d in Q2/26, inclusive of completing a planned turnaround at one of its central processing facilities in the quarter.
 - Jackfish production exceeded its facility nameplate capacity of 120,000 bbl/d by approximately 16,400 bbl/d on average in Q2/26 as a result of strong performance from the Pike 1 pads combined with facility optimization including interconnectivity and debottlenecking.
 - The two new SAGD pads at Pike 1 continue to exceed expectations, with current combined production of approximately 46,000 bbl/d and a Steam to Oil Ratio ("SOR") of 1.8x. The Pike 1 SAGD pads are top tier in industry, driven by high quality resource, and continuous improvement in technology and execution.
 - Thermal in situ operating costs averaged \$11.89/bbl (US\$8.59/bbl) in Q2/26, an increase of approximately 8% compared to \$11.05/bbl in Q2/25, reflecting the cyclic nature of steam cycles at Primrose, partially offset by strong Pike 1 performance.
- As part of the Company's defined short-term growth strategy, Canadian Natural has decades of robust capital efficient drill to fill growth opportunities on its long life low decline thermal in situ assets, which we continue to develop in a disciplined manner to deliver safe and reliable thermal in situ production.
 - At Primrose, the Company brought a recently drilled Cyclic Steam Stimulation ("CSS") pad on production subsequent to quarter end, in July 2026. In the second half of 2026, the Company is drilling and completing two additional CSS pads which are targeted to come on production in 2027.
 - At Kirby, the Company is currently drilling a SAGD pad, which is targeted to come on production in 2027.

- Canadian Natural has been piloting solvent enhanced oil recovery technology on certain thermal in situ assets with an objective to increase bitumen production while reducing the SOR and GHG emissions, at the same time optimizing solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
- As a result of strong production performance from new wells at the Kirby South pilot, the Company is targeting to begin solvent injection using diluent in Q1/27.

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs production (bbl/d)	338,138	328,591	271,022	333,391	273,761
Net crude oil wells drilled	80	83	57	163	114
Net successful crude oil wells drilled	80	83	57	163	113
Success rate	100%	100%	100%	100%	99%

- Record quarterly North America E&P liquids production, excluding thermal in situ operations, of 338,138 bbl/d was achieved in Q2/26, an increase of approximately 67,000 bbl/d or 25% from Q2/25 levels. This record reflects opportunistic acquisitions and strong organic growth from heavy crude oil multilaterals, light crude oil and NGLs.
- Strong primary heavy crude oil production averaged 89,444 bbl/d in Q2/26, an increase of 2% from Q2/25 levels, reflecting quick payout, high return multilateral wells.
 - Canadian Natural's highly successful multilateral drilling program continues to unlock opportunities on our 3 million net acres of high quality, multizone land throughout our primary heavy crude oil assets.
 - The Company's continuous improvement in multilateral execution resulted in 12% faster drilling times year to date in 2026 compared to the 2025 average, achieving an average drill length of 12,900 meters per well for approximately the same cost as our 2025 program at 11,500 meters per well.
 - Operating costs in the Company's primary heavy crude oil operations averaged \$17.73/bbl (US\$12.81/bbl) in Q2/26, comparable to \$17.44/bbl in Q2/25.
- In the Company's Pelican Lake polymer flood area, production averaged 44,053 bbl/d in Q2/26, an increase of 2% from Q2/25 levels, reflecting strong results from Driftwood and the long life low decline nature of these assets.
 - Our low operating costs at Pelican Lake averaged \$9.70/bbl (US\$7.01/bbl) in Q2/26, an increase from \$9.01/bbl in Q2/25, reflecting increased trucked production from Driftwood.
- Record quarterly production of 204,641 bbl/d was achieved in North America light crude oil and NGLs in Q2/26, an increase of approximately 64,000 bbl/d or 45% from Q2/25 levels, primarily reflecting accretive acquisitions and strong drilling results.
 - Operating costs in the Company's North America light crude oil and NGLs operations averaged \$13.29/bbl (US\$9.60/bbl) in Q2/26, an increase of \$2.35/bbl from Q2/25 levels, primarily reflecting higher NGL processing costs.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Natural gas production (MMcf/d)	2,563	2,668	2,398	2,616	2,417
Net natural gas wells drilled	23	24	22	47	41
Net successful natural gas wells drilled	23	24	22	47	41
Success rate	100%	100%	100%	100%	100%

- North America natural gas production averaged 2,563 MMcf/d in Q2/26, an increase of 7% from Q2/25 levels, reflecting liquids-rich natural gas acquisitions completed in 2025 and 2026 and strong liquids-rich natural gas drilling results, partially offset by natural field declines. North America natural gas operating costs averaged \$1.25/Mcf in Q2/26.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil production (bbl/d)	10,390	6,868	9,530	8,639	13,468
Natural gas production (MMcf/d)	4	2	9	3	12

- International E&P crude oil production volumes averaged 10,390 bbl/d in Q2/26, an increase of 9% compared to Q2/25 levels. The increase reflects the return of production at Baobab in Offshore Africa in June 2026 following the completion of the refurbishment of the floating production storage and offloading ("FPSO") vessel, partially offset by the planned North Sea abandonments conducted as part of the previously announced decommissioning activities.
 - At Baobab, since resuming steady production, net volumes have averaged approximately 10,000 BOE/d, approximately 2,000 BOE/d higher than budget due to higher than expected reservoir pressure.

Drilling Activity

	Three Months Ended				Six Months Ended			
	June 30, 2026		June 30, 2025		June 30, 2026		June 30, 2025	
(number of wells)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil ⁽¹⁾	120	118	85	81	238	231	160	155
Natural gas	29	23	27	22	59	47	50	41
Dry	—	—	—	—	1	1	1	1
Subtotal	149	141	112	103	298	279	211	197
Stratigraphic test / service wells	21	21	29	28	561	561	513	490
Total	170	162	141	131	859	840	724	687
Success rate (excluding stratigraphic test / service wells)	100%		100%		99%		99%	

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 279 net crude oil and natural gas wells in the first half of 2026, 82 more than in the first half of 2025.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Benchmark Commodity Prices					
WTI benchmark price (US\$/bbl) ⁽¹⁾	\$ 92.85	\$ 72.17	\$ 63.71	\$ 82.57	\$ 67.55
WCS heavy differential (discount) to WTI (US\$/bbl) ⁽¹⁾	\$ (14.62)	\$ (14.12)	\$ (10.19)	\$ (14.37)	\$ (11.42)
WCS heavy differential as a percentage of WTI (%) ⁽¹⁾	16%	20%	16%	17%	17%
Condensate benchmark price (US\$/bbl)	\$ 95.59	\$ 71.65	\$ 63.42	\$ 83.69	\$ 66.64
SCO price (US\$/bbl) ⁽¹⁾	\$ 101.22	\$ 71.75	\$ 64.69	\$ 86.57	\$ 66.87
SCO premium (discount) to WTI (US\$/bbl) ⁽¹⁾	\$ 8.37	\$ (0.42)	\$ 0.98	\$ 4.00	\$ (0.68)
AECO benchmark price (C\$/GJ)	\$ 1.43	\$ 2.36	\$ 1.97	\$ 1.89	\$ 1.94
Realized Prices					
Exploration & Production liquids realized price (C\$/bbl) ⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾	\$ 105.11	\$ 76.02	\$ 69.58	\$ 90.77	\$ 74.82
SCO realized price (C\$/bbl) ⁽¹⁾⁽³⁾⁽⁴⁾⁽⁵⁾	\$ 125.78	\$ 89.68	\$ 87.22	\$ 108.26	\$ 91.88
Natural gas realized price (C\$/Mcf) ⁽⁴⁾	\$ 2.05	\$ 3.32	\$ 2.58	\$ 2.69	\$ 2.86

(1) West Texas Intermediate ("WTI"); Western Canadian Select ("WCS"); Synthetic Crude Oil ("SCO").

(2) Exploration & Production crude oil and NGLs average realized price excludes SCO.

(3) Pricing is net of blending and feedstock costs.

(4) Excludes risk management activities.

(5) Non-GAAP ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

- Canadian Natural has a balanced and diverse product mix of SCO, light crude oil, NGLs, heavy crude oil, bitumen and natural gas, complemented with a balanced and diverse marketing strategy.
 - Approximately 840,000 bbl/d or 67% of total liquids production in Q2/26 consisted of SCO, light crude oil and NGLs.
 - The SCO price premium to WTI was strong in Q2/26, averaging US\$8.37/bbl, primarily driven by stronger refinery demand amid tighter crude and refined product markets due to Middle East supply disruptions and reduced WCSB supply due to weather-related impacts and seasonal maintenance in Q2/26.
 - Current SCO annual average strip pricing in 2026 represents a premium to WTI of approximately US\$3.80/bbl.
- Canadian Natural has total contracted crude oil export transportation capacity of 256,500 bbl/d, consisting of committed volumes to Canada's west coast and to the United States Gulf Coast, being approximately 21% of 2026 forecasted liquids production. The egress supports Canadian Natural's long-term sales strategy by targeting diverse refining markets which drive stronger netbacks while also reducing exposure to egress constraints.
- The North West Redwater refinery, 50% owned by the Company, primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 92,748 bbl/d in Q2/26.
- Canadian Natural has a diversified natural gas marketing strategy with the Company in 2026 to consume the equivalent of approximately 31% of forecasted natural gas production in its Oil Sands Mining and Upgrading and thermal operations, with approximately 38% targeted to be sold at AECO/Station 2 pricing, and approximately 31% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value.
- Canadian Natural has a long-term natural gas supply agreement with Cheniere Marketing, LLC. ("Cheniere") as part of the Sabine Pass Liquefaction Expansion Project where the Company has agreed to sell 140,000 MMBtu/d of natural gas to Cheniere for a term of 15 years, with delivery anticipated to begin in 2030.
 - Under the terms of the agreement, Canadian Natural will deliver natural gas to Cheniere in Chicago and receive a Japan Korea Marker ("JKM") index price less deductions for transportation and liquefaction.

ADVISORY

Special Note Regarding Non-GAAP and Other Financial Measures

This document includes references to non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS Accounting Standards and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this document and the Company's MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three and six months ended June 30, 2026 dated August 5, 2026.

Free Cash Flow Allocation Policy

Free cash flow is a non-GAAP financial measure. The Company considers free cash flow a key measure in demonstrating the Company's ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders and to repay or maintain net debt levels, pursuant to the free cash flow allocation policy.

The Company's free cash flow is used to determine the targeted amount of shareholder returns after dividends. The amount allocated to shareholders varies depending on the Company's net debt position.

Free cash flow is calculated as adjusted funds flow less dividends on common shares, net capital expenditures and abandonment expenditures. The Company targets to manage the allocation of free cash flow on a forward-looking annual basis, while managing working capital and cash requirements as needed.

In March 2026, the Board of Directors adjusted the allocation of free cash flow, effective January 1, 2026, as follows:

- When net debt is at or above \$16 billion, 60% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases and 40% to the balance sheet.
- When net debt is between \$13 billion and \$16 billion, 75% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases and 25% to the balance sheet.
- When net debt is at or below \$13 billion, 100% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases.

The Company's free cash flow for the three months ended June 30, 2026 and comparable periods is shown below:

(\$ millions)	Three Months Ended		
	Jun 30 2026	Mar 31 2026	Jun 30 2025
Adjusted funds flow ⁽¹⁾	\$ 6,866	\$ 4,374	\$ 3,262
Less: Dividends on common shares	1,304	1,224	1,233
Net capital expenditures ⁽¹⁾	2,405	2,028	1,915
Abandonment expenditures	182	247	193
Free cash flow	\$ 2,975	\$ 875	\$ (79)

(1) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three and six months ended June 30, 2026 dated August 5, 2026.

Long-term Debt, net

Long-term debt, net (also referred to as net debt) is a capital management measure that is calculated as current and long-term debt less cash and cash equivalents.

(\$ millions)	Jun 30 2026	Mar 31 2026	Dec 31 2025	Jun 30 2025
Long-term debt	\$ 17,144	\$ 16,961	\$ 16,617	\$ 17,081
Less: cash and cash equivalents	2,618	808	673	102
Long-term debt, net	\$ 14,526	\$ 16,153	\$ 15,944	\$ 16,979

Breakeven WTI Price

The breakeven WTI price is a supplementary financial measure that represents the equivalent US dollar WTI price per barrel where the Company's adjusted funds flow is equal to the sum of maintenance capital and dividends. The Company considers the breakeven WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The breakeven WTI price incorporates the non-GAAP financial measure adjusted funds flow as reconciled in the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A. Maintenance capital is a supplementary financial measure that represents the capital required to maintain annual production at prior period levels.

Capital Budget

Capital budget (or capital forecast) is a forward-looking non-GAAP financial measure. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns, and the balancing of project risks and time horizons.

The capital budget (or capital forecast) excludes abandonment expenditures related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these forecasted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries in Canada and the UK portion of the North Sea. The Company is eligible to recover interest related to tax recoveries in the North Sea.

Capital Efficiency

Capital efficiency is a supplementary financial measure that represents the capital spent to add new or incremental production divided by the current rate of the new or incremental production. It is expressed as a dollar amount per flowing volume of a product (\$/bbl/d or \$/BOE/d). The Company considers capital efficiency a key measure in evaluating its performance, as it demonstrates the efficiency of the Company's capital investments.

This Page Left Intentionally Blank

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORY

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "focus", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration", or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to the Company's strategy or strategic focus, capital budget, expected future commodity pricing, forecasted or anticipated production volumes, royalties, production expenses, capital expenditures, forecasted and anticipated abandonment expenditures, income tax expenses, and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, including the strength of the Company's balance sheet, the sources and adequacy of the Company's liquidity, and the flexibility of the Company's capital structure, constitute forward-looking statements. Disclosure of plans relating to, and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), the Primrose thermal oil projects ("Primrose"), the Pelican Lake water and polymer flood projects ("Pelican Lake"), the Kirby thermal oil sands project ("Kirby"), the Jackfish thermal oil sands project ("Jackfish"), and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of crude oil, bitumen, natural gas, natural gas liquids ("NGLs"), or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market; the maintenance of the Company's facilities and any expected return to service dates; the construction, expansion, or maintenance of third-party facilities that process the Company's products; the abandonment and decommissioning of certain assets and the timing thereof; the development and deployment of technology and technological innovations; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the materiality of the impact of tax interpretations and litigation on the Company's results, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives, or expectations upon which they are based will occur. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, bitumen, natural gas, and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates, and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance, or achievements of the Company to be materially different from any future results, performance, or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+"), the impact of conflicts in the Middle East and in Ukraine, the restriction or disruption of global trade routes, the impact of changes to US economic policy, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, bitumen, natural gas, and NGLs prices; the impact of the ramp-up of LNG Canada on commodity prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; changes and uncertainties in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded); uncertainty in the regulatory framework governing greenhouse gas emissions including, among other things, financial and other support from various levels of government for climate related initiatives and potential emissions or production caps, and the timing, impact, and success of the implementation of the Memorandum of Understanding ("MOU") entered into between the Government of Canada and the Government of Alberta in November 2025 and the trilateral Memorandum of Understanding ("trilateral MOU") entered into between the Oil Sands Alliance, the Government of Alberta, and the Government of Canada in July 2026, including the execution of definitive agreements and satisfaction of other regulatory, financial and other conditions contemplated thereunder; civil unrest and political uncertainty, including changes in government, actions of or against terrorists, insurgent groups, or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack, other cyber-related crime, and other cyber-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling, and other equipment; ability of the Company to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting, or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in the mining, extracting, or upgrading of the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and NGLs not currently

classified as proved; changes to future abandonment and decommissioning costs; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state, and local laws and regulations such as restrictions on production or emissions, the imposition of tariffs, embargoes, or export restrictions on the Company's products (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded), changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations (including the implementation of the MOU and the trilateral MOU). Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity, and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Special Note Regarding Non-GAAP and Other Financial Measures

This MD&A includes references to non-GAAP measures, which include non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). Non-GAAP measures are used by the Company to evaluate its financial performance, financial position, or cash flow. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Special Note Regarding Amendments to the *Competition Act* (Canada)

On June 20, 2024, amendments to the *Competition Act* (Canada) came into force with the adoption of Bill C-59, *An Act to Implement Certain Provisions of the Fall Economic Statement*, which impact environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the *Competition Act's* deceptive marketing practices provisions. Subsequently, on March 26, 2026, the *Competition Act* was further amended to remove the requirement that businesses substantiate their environmental representations about a business or business activity based on an internationally recognized methodology, and eliminate private rights of action under the revised business-activity greenwashing provision. Notwithstanding these amendments, uncertainty surrounding the interpretation and enforcement of this legislation, which includes any future amendments, may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three and six months ended June 30, 2026, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2025. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three and six months ended June 30, 2026 and this MD&A have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards").

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil ("6 Mcf:1 bbl"). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, and SCO (including mining bitumen). Production on an "after royalties" or "company net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three and six months ended June 30, 2026 in relation to the comparable periods in 2025 and the first quarter of 2026. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2025, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information in such Annual Information Form and on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated August 5, 2026.

FINANCIAL HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Product sales ⁽¹⁾	\$ 17,214	\$ 12,404	\$ 9,675	\$ 29,618	\$ 22,387
Crude oil and NGLs	\$ 16,067	\$ 11,114	\$ 8,874	\$ 27,181	\$ 20,606
Natural gas	\$ 503	\$ 832	\$ 600	\$ 1,335	\$ 1,316
Net earnings	\$ 4,503	\$ 1,348	\$ 2,459	\$ 5,851	\$ 4,917
Per common share – basic	\$ 2.17	\$ 0.65	\$ 1.17	\$ 2.81	\$ 2.34
– diluted	\$ 2.15	\$ 0.64	\$ 1.17	\$ 2.80	\$ 2.34
Adjusted net earnings from operations ⁽²⁾	\$ 4,568	\$ 2,446	\$ 1,496	\$ 7,014	\$ 3,932
Per common share – basic ⁽³⁾	\$ 2.20	\$ 1.17	\$ 0.71	\$ 3.37	\$ 1.88
– diluted ⁽³⁾	\$ 2.19	\$ 1.17	\$ 0.71	\$ 3.35	\$ 1.87
Cash flows from operating activities	\$ 6,823	\$ 3,282	\$ 3,114	\$ 10,105	\$ 7,398
Adjusted funds flow ⁽²⁾	\$ 6,866	\$ 4,374	\$ 3,262	\$ 11,240	\$ 7,792
Per common share – basic ⁽³⁾	\$ 3.30	\$ 2.10	\$ 1.56	\$ 5.40	\$ 3.72
– diluted ⁽³⁾	\$ 3.28	\$ 2.09	\$ 1.55	\$ 5.37	\$ 3.70
Cash flows used in investing activities	\$ 2,468	\$ 1,949	\$ 1,941	\$ 4,417	\$ 3,253
Net capital expenditures ⁽²⁾	\$ 2,405	\$ 2,028	\$ 1,915	\$ 4,433	\$ 3,218
Abandonment expenditures	\$ 182	\$ 247	\$ 193	\$ 429	\$ 381

(1) Further details related to product sales are disclosed in note 17 to the financial statements.

(2) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the six months ended June 30, 2026 were \$5,851 million compared with \$4,917 million for the six months ended June 30, 2025. Net earnings for the six months ended June 30, 2026 included non-operating losses, net of tax, of \$1,163 million compared with non-operating income of \$985 million for the six months ended June 30, 2025 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, and the gain on acquisition in 2025. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2026 were \$7,014 million compared with \$3,932 million for the six months ended June 30, 2025. Further details related to the movements in adjusted net earnings from operations are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Net earnings for the second quarter of 2026 were \$4,503 million compared with \$2,459 million for the second quarter of 2025 and \$1,348 million for the first quarter of 2026. Net earnings for the second quarter of 2026 included non-operating losses, net of tax, of \$65 million compared with non-operating income of \$963 million for the second quarter of 2025 and non-operating losses of \$1,098 million for the first quarter of 2026 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, and the gain on acquisition in 2025. Excluding these items, the Company achieved record quarterly adjusted net earnings from operations during the second quarter of 2026 of \$4,568 million, the highest in the Company's history, compared with \$1,496 million for the second quarter of 2025 and \$2,446 million for the first quarter of 2026. Further details related to the movements in adjusted net earnings from operations are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

The increase in net earnings and adjusted net earnings from operations for the six months ended June 30, 2026 from the six months ended June 30, 2025 primarily reflected:

- higher realized SCO pricing⁽¹⁾ and sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher realized crude oil and NGLs pricing⁽¹⁾ and sales volumes in the North America Exploration and Production segment.

(1) Non-GAAP ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

The increase in net earnings and adjusted net earnings from operations for the second quarter of 2026 from the second quarter of 2025 and the first quarter of 2026 primarily reflected:

- higher realized SCO pricing and sales volumes in the Oil Sands Mining and Upgrading segment; and
 - higher realized crude oil and NGLs pricing and sales volumes in the North America Exploration and Production segment;
- partially offset by:
- lower natural gas realized pricing in the North America Exploration and Production segment.

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange loss (gain), and the gain on acquisition in 2025 also contributed to the movements in net earnings from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the six months ended June 30, 2026 were \$10,105 million compared with \$7,398 million for the six months ended June 30, 2025. Cash flows from operating activities for the second quarter of 2026 were \$6,823 million compared with \$3,114 million for the second quarter of 2025 and \$3,282 million for the first quarter of 2026. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for the six months ended June 30, 2026 was \$11,240 million compared with \$7,792 million for the six months ended June 30, 2025. The Company achieved record quarterly adjusted funds flow during the second quarter of 2026 of \$6,866 million, the highest in the Company's history, compared with \$3,262 million for the second quarter of 2025 and \$4,374 million for the first quarter of 2026. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets, including the unamortized cost of contributions to the Company's employee bonus program, interest on Petroleum Revenue Tax ("PRT") recoveries, and prepaid cost of service tolls. Further details related to the movements in adjusted funds flow are discussed in the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Production Volumes

The Company achieved record quarterly crude oil and NGLs production before royalties during the second quarter of 2026 of 1,248,889 bbl/d, the highest in the Company's history and an increase of 23% from 1,019,149 bbl/d for the second quarter of 2025, and an increase of 4% from 1,198,079 bbl/d for the first quarter of 2026. Natural gas production before royalties for the second quarter of 2026 of 2,567 MMcf/d increased 7% from 2,407 MMcf/d for the second quarter of 2025 and decreased 4% from 2,670 MMcf/d for the first quarter of 2026. Total production before royalties for the second quarter of 2026 of 1,676,754 BOE/d increased 18% from 1,420,358 BOE/d for the second quarter of 2025 and was comparable with 1,643,160 BOE/d for the first quarter of 2026. Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production, before royalties' section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, the realized crude oil and NGLs price averaged \$105.11 per bbl for the second quarter of 2026, an increase of 51% from \$69.58 per bbl for the second quarter of 2025 and an increase of 38% from \$76.02 per bbl for the first quarter of 2026. The realized natural gas price decreased 21% to average \$2.05 per Mcf for the second quarter of 2026 from \$2.58 per Mcf for the second quarter of 2025 and decreased 38% from \$3.32 per Mcf for the first quarter of 2026. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price increased 44% to average \$125.78 per bbl for the second quarter of 2026 from \$87.22 per bbl for the second quarter of 2025 and increased 40% from \$89.68 per bbl for the first quarter of 2026. The Company's realized product pricing is reflective of the prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the 'Business Environment', 'Realized Product Prices – Exploration and Production', and 'Realized Product Prices, Royalties and Transportation – Oil Sands Mining and Upgrading' sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense⁽¹⁾ averaged \$14.99 per bbl for the second quarter of 2026, an increase of 7% from \$14.03 per bbl for the second quarter of 2025 and an increase of 11% from \$13.54 per bbl for the first quarter of 2026. Natural gas production expense⁽¹⁾ averaged \$1.28 per Mcf for the second quarter of 2026, an increase of 15% from \$1.11 per Mcf for the second quarter of 2025 and an increase of 3% from \$1.24 per Mcf for the first quarter of 2026. In the Oil Sands Mining and Upgrading segment, production expense⁽¹⁾ averaged \$22.19 per bbl for the second quarter of 2026, a decrease of 16% from \$26.53 per bbl for the second quarter of 2025 and a decrease of 6% from \$23.73 per bbl for the first quarter of 2026. Crude oil and NGLs and natural gas production expense is discussed in detail in the 'Production Expense – Exploration and Production' and 'Production Expense – Oil Sands Mining and Upgrading' sections of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

The following is a summary of the Company's quarterly financial results for the eight most recently completed quarters:

(\$ millions, except per common share amounts)	Jun 30 2026	Mar 31 2026	Dec 31 2025	Sep 30 2025
Product sales ⁽¹⁾	\$ 17,214	\$ 12,404	\$ 10,710	\$ 11,070
Crude oil and NGLs	\$ 16,067	\$ 11,114	\$ 9,666	\$ 10,468
Natural gas	\$ 503	\$ 832	\$ 735	\$ 399
Net earnings	\$ 4,503	\$ 1,348	\$ 5,303	\$ 600
Net earnings per common share				
– basic	\$ 2.17	\$ 0.65	\$ 2.55	\$ 0.29
– diluted	\$ 2.15	\$ 0.64	\$ 2.54	\$ 0.29
(\$ millions, except per common share amounts)	Jun 30 2025	Mar 31 2025	Dec 31 2024	Sep 30 2024
Product sales ⁽¹⁾	\$ 9,675	\$ 12,712	\$ 11,064	\$ 10,401
Crude oil and NGLs	\$ 8,874	\$ 11,732	\$ 10,381	\$ 9,943
Natural gas	\$ 600	\$ 716	\$ 451	\$ 257
Net earnings	\$ 2,459	\$ 2,458	\$ 1,138	\$ 2,266
Net earnings per common share				
– basic	\$ 1.17	\$ 1.17	\$ 0.54	\$ 1.07
– diluted	\$ 1.17	\$ 1.17	\$ 0.54	\$ 1.06

(1) Further details related to product sales for the three months ended June 30, 2026 and 2025 are disclosed in note 17 to the financial statements.

Volatility in the quarterly net earnings over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – Fluctuations in global supply/demand including crude oil production levels from OPEC+ and its impact on world supply; the impact of geopolitical and market uncertainties (including those due to the conflicts in the Middle East and in Ukraine, the restriction or disruption of global trade routes, and the impacts of ongoing tariff and trade uncertainty) on worldwide benchmark pricing; the impact of shale oil production in North America; market egress including the Trans Mountain Expansion ("TMX") pipeline; the impact of increased supply of heavy crude oil from Venezuela; the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America; and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the International segments.
- **Natural gas pricing** – Fluctuations in both the demand for natural gas and inventory storage levels; the impact of third-party pipeline maintenance and outages; the impact of geopolitical and market uncertainties; the impact of seasonal conditions; the impact of liquefied natural gas ("LNG") demand and exports; and the impact of shale gas production in the US.

(1) Calculated as respective production expense divided by respective sales volumes.

- **Crude oil and NGLs sales volumes** – Fluctuations in production from Kirby and Jackfish; fluctuations in production due to the cyclic nature of Primrose; fluctuations in the Company's drilling program in the North America Exploration and Production segment; natural field declines; the impact of turnarounds in the Oil Sands Mining and Upgrading segment; the impact and timing of acquisitions (including the acquisition of working interests in AOSP and Duvernay assets in the fourth quarter of 2024; the acquisition of assets in the Palliser Block in the second quarter of 2025, the acquisition of assets in the Grande Prairie area in the third quarter of 2025, the AOSP asset swap in the fourth quarter of 2025, and the acquisitions of assets in the Peace River area in the first and second quarters of 2026); wildfires; and maintenance activities in the North America Exploration and Production segment. Sales volumes in the International segments also reflected fluctuations due to the timing of liftings, planned abandonment activities in the North Sea, and temporary suspension of production at Baobab in Offshore Africa for planned floating production, storage and offloading vessel ("FPSO") maintenance, which returned to service during the second quarter of 2026.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in the North America Exploration and Production segment; the impact and timing of acquisitions (including the acquisition of a working interest in the Duvernay assets in the fourth quarter of 2024, the acquisition of assets in the Palliser Block in the second quarter of 2025, the acquisition of assets in the Grande Prairie area in the third quarter of 2025, and the acquisitions of assets in the Peace River area in the first and second quarters of 2026); natural field declines; the impact of seasonal conditions; and wildfires in the North America Exploration and Production segment.
- **Production expense** – Fluctuations primarily due to the impacts of the demand and cost for services; fluctuations in product mix and production volumes; seasonal conditions; carbon tax; fluctuating energy costs; inflationary cost pressures; cost optimizations across all segments; turnarounds in the Oil Sands Mining and Upgrading segment; and maintenance activities.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes; timing of acquisitions; proved reserves; asset retirement obligations; finding and development costs associated with crude oil and natural gas exploration; estimated future costs to develop the Company's proved undeveloped reserves; fluctuations in International sales volumes subject to higher depletion rates; the impact of turnarounds in the Oil Sands Mining and Upgrading segment; the impact on the depletable base resulting from the gain recognized on the AOSP mine assets in the fourth quarter of 2025; and recoverability charges related to the North Sea and Offshore Africa.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market, and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to changing long-term debt levels and lease liabilities; the impact of movements in benchmark interest rates on outstanding floating rate long-term debt; and interest on PRT recoveries.
- **Foreign exchange** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt and working capital.
- **Gain on acquisitions, disposition, and remeasurement** – Fluctuations due to gain on acquisitions, representing the excess of the fair value of the net assets acquired compared to total purchase consideration and previously held interests. A gain on remeasurement to fair value of the Company's pre-existing 90% interest in the AOSP mines and a gain on disposition of the 10% interest in the non-operated Scotford Upgrader ("Scotford") and the Quest Carbon Capture and Storage facility ("Quest") disposed of as part of the AOSP asset swap in the fourth quarter of 2025.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing increased in the second quarter of 2026 from continued conflict in the Middle East and the resulting supply disruptions. Releases from global crude oil inventories in the second quarter helped to mitigate these disruptions, while a negotiated ceasefire reduced pricing at the end of the quarter. Crude oil pricing is expected to remain volatile in the near-term amid ongoing geopolitical uncertainty. Although prices are anticipated to stabilize once conflict-related risks subside and supply-demand fundamentals reassert themselves, a resumption of conflict could materially impact crude oil pricing into the second half of 2026.

Natural gas benchmark pricing decreased in the second quarter of 2026, driven by increased production and inventory levels combined with a decrease in LNG export demand due to seasonal maintenance activities at the US Gulf Coast. In Canada, AECO benchmark pricing decreased due to seasonal demand factors, and reduced exports out of the Western Canadian Sedimentary Basin ("WCSB"). The continued ramp-up of LNG Canada is expected to further increase LNG demand and provide incremental support to AECO pricing through 2026.

Trilateral Memorandum of Understanding Update

In July 2026, the Oil Sands Alliance, the Government of Alberta, and the Government of Canada entered into a trilateral MOU. The trilateral MOU outlines a potential regulatory and fiscal framework intended to support the competitiveness of Canada's energy industry. Implementation of the framework contemplated by the trilateral MOU remains subject to definitive agreements and regulatory approvals.

Benchmark Commodity Prices

(Average for the period)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
WTI benchmark price (US\$/bbl)	\$ 92.85	\$ 72.17	\$ 63.71	\$ 82.57	\$ 67.55
Dated Brent benchmark price (US\$/bbl)	\$ 104.51	\$ 80.93	\$ 67.78	\$ 92.78	\$ 71.71
WCS Heavy Differential from WTI (US\$/bbl)	\$ 14.62	\$ 14.12	\$ 10.19	\$ 14.37	\$ 11.42
SCO price (US\$/bbl)	\$ 101.22	\$ 71.75	\$ 64.69	\$ 86.57	\$ 66.87
Condensate benchmark price (US\$/bbl)	\$ 95.59	\$ 71.65	\$ 63.42	\$ 83.69	\$ 66.64
NYMEX benchmark price (US\$/MMBtu)	\$ 2.89	\$ 4.96	\$ 3.44	\$ 3.92	\$ 3.55
AECO benchmark price (C\$/GJ)	\$ 1.43	\$ 2.36	\$ 1.97	\$ 1.89	\$ 1.94
US/Canadian dollar average exchange rate (US\$)	\$ 0.7225	\$ 0.7290	\$ 0.7225	\$ 0.7257	\$ 0.7096

Substantially all of the Company's production is sold based on US dollar benchmark pricing, with crude oil marketed based on WTI and Brent indices, and natural gas marketed using a diversified mix of AECO- and NYMEX-based pricing. The Company's realized prices are directly impacted by fluctuations in foreign exchange rates, which affect product revenues as Canadian dollar sales prices change relative to the US dollar benchmark prices.

Crude Oil

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US\$82.57 per bbl for the six months ended June 30, 2026, an increase of 22% from US\$67.55 per bbl for the six months ended June 30, 2025. WTI averaged US\$92.85 per bbl for the second quarter of 2026, an increase of 46% from US\$63.71 per bbl for the second quarter of 2025 and an increase of 29% from US\$72.17 per bbl for the first quarter of 2026.

Crude oil sales contracts for the Company's International segments are typically based on Brent benchmark pricing, which is representative of international markets and overall global supply and demand. Brent averaged US\$92.78 per bbl for the six months ended June 30, 2026, an increase of 29% from US\$71.71 per bbl for the six months ended June 30, 2025. Brent averaged US\$104.51 per bbl for the second quarter of 2026, an increase of 54% from US\$67.78 per bbl for the second quarter of 2025 and an increase of 29% from US\$80.93 per bbl for the first quarter of 2026.

The increase in WTI and Brent benchmark pricing for the three and six months ended June 30, 2026 from the comparable periods primarily reflected continued conflict in the Middle East and the resulting global supply disruptions, partially offset by releases of global crude oil inventories in the second quarter of 2026 and weaker demand.

The WCS Heavy Differential averaged US\$14.37 per bbl for the six months ended June 30, 2026, compared with US\$11.42 per bbl for the six months ended June 30, 2025. The WCS Heavy Differential averaged US\$14.62 per bbl for the second quarter of 2026, compared with US\$10.19 per bbl for the second quarter of 2025 and US\$14.12 per bbl for the first quarter of 2026. The widening of the WCS Heavy Differential for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected strong WTI benchmark pricing and increased heavy crude oil availability at the US Gulf Coast, partially offset by a tightening of the sour crude oil market due to Middle East supply disruptions.

The SCO price averaged US\$86.57 per bbl for the six months ended June 30, 2026, an increase of 29% from US\$66.87 per bbl for the six months ended June 30, 2025. SCO pricing averaged US\$101.22 per bbl for the second quarter of 2026, an increase of 56% from US\$64.69 per bbl for the second quarter of 2025 and an increase of 41% from US\$71.75 per bbl for the first quarter of 2026. The increase in SCO pricing for the three and six months ended June 30, 2026 from the comparable periods primarily reflected higher WTI benchmark pricing and stronger refinery demand amid tighter crude oil and refined product markets due to Middle East supply disruptions. The increase in SCO pricing for the second quarter of 2026 from the first quarter of 2026 also reflected reduced WCSB supply due to weather-related impacts and seasonal maintenance.

Natural Gas

NYMEX benchmark pricing averaged US\$3.92 per MMBtu for the six months ended June 30, 2026, an increase of 10% from US\$3.55 per MMBtu for the six months ended June 30, 2025. NYMEX benchmark pricing averaged US\$2.89 per MMBtu for the second quarter of 2026, a decrease of 16% from US\$3.44 per MMBtu for the second quarter of 2025 and a decrease of 42% from US\$4.96 per MMBtu for the first quarter of 2026. The increase in NYMEX natural gas pricing for the six months ended June 30, 2026 from the six months ended June 30, 2025 primarily reflected strong LNG demand and exports out of the US Gulf Coast, and weather-related outages in the Eastern US following severe winter storms early in the first quarter of 2026. The decrease in NYMEX natural gas pricing for the second quarter of 2026 from the second quarter of 2025 primarily reflected increased US production and inventory levels, partially offset by stronger LNG exports out of the US Gulf Coast. The decrease in NYMEX natural gas pricing for the second quarter of 2026 from the first quarter of 2026 primarily reflected seasonal demand factors and reduced LNG exports due to planned maintenance activities in the US Gulf Coast, combined with increased US production and inventory levels.

AECO benchmark pricing averaged \$1.89 per GJ for the six months ended June 30, 2026, comparable with \$1.94 per GJ for the six months ended June 30, 2025. AECO benchmark pricing averaged \$1.43 per GJ for the second quarter of 2026, a decrease of 27% from \$1.97 per GJ for the second quarter of 2025 and a decrease of 39% from \$2.36 per GJ for the first quarter of 2026. The decrease in AECO natural gas pricing for the second quarter of 2026 from the second quarter of 2025 primarily reflected lower NYMEX benchmark pricing and reduced exports out of the WCSB. The decrease in AECO natural gas pricing for the second quarter of 2026 from the first quarter of 2026 primarily reflected lower NYMEX benchmark pricing, and seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	613,745	603,265	545,811	608,534	553,482
North America – Oil Sands Mining and Upgrading ⁽¹⁾	624,754	587,946	463,808	606,452	529,099
International – Exploration and Production					
North Sea	6,589	4,829	7,761	5,714	9,623
Offshore Africa	3,801	2,039	1,769	2,925	3,845
Total International ⁽²⁾	10,390	6,868	9,530	8,639	13,468
Total Crude oil and NGLs	1,248,889	1,198,079	1,019,149	1,223,625	1,096,049
Natural gas (MMcf/d) ⁽³⁾					
North America	2,563	2,668	2,398	2,616	2,417
International					
North Sea	2	2	3	2	4
Offshore Africa	2	—	6	1	8
Total International	4	2	9	3	12
Total Natural gas	2,567	2,670	2,407	2,619	2,429
Total Barrels of oil equivalent (BOE/d)	1,676,754	1,643,160	1,420,358	1,660,050	1,500,905
Product mix					
Light and medium crude oil and NGLs	13%	12%	11%	13%	10%
Pelican Lake heavy crude oil	3%	2%	3%	2%	3%
Primary heavy crude oil	5%	6%	6%	6%	6%
Thermal bitumen	16%	17%	19%	17%	19%
Synthetic crude oil ⁽¹⁾	37%	36%	33%	37%	35%
Natural gas	26%	27%	28%	25%	27%
Percentage of product sales ^{(1) (4) (5)}					
Crude oil and NGLs	97%	92%	93%	95%	93%
Natural gas	3%	8%	7%	5%	7%

(1) SCO production before royalties excludes SCO consumed internally as diesel.

(2) "International" includes North Sea and Offshore Africa Exploration and Production segments in all instances used in this MD&A.

(3) Natural gas production volumes approximate sales volumes.

(4) Net of blending and feedstock costs and excluding risk management activities.

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	496,377	497,369	472,329	496,870	463,865
North America – Oil Sands Mining and Upgrading ⁽¹⁾	515,113	490,850	397,052	503,049	438,410
International – Exploration and Production					
North Sea	6,579	4,825	7,746	5,707	9,609
Offshore Africa	3,626	2,039	1,692	2,837	3,678
Total International	10,205	6,864	9,438	8,544	13,287
Total Crude oil and NGLs	1,021,695	995,083	878,819	1,008,463	915,562
Natural gas (MMcf/d)					
North America	2,476	2,544	2,325	2,510	2,336
International					
North Sea	2	2	3	2	4
Offshore Africa	2	—	6	1	8
Total International	4	2	9	3	12
Total Natural gas	2,480	2,546	2,334	2,513	2,348
Total Barrels of oil equivalent (BOE/d)	1,435,078	1,419,481	1,267,787	1,427,323	1,306,945

(1) SCO production net of royalties excludes SCO consumed internally as diesel.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, SCO, and natural gas.

Crude oil and NGLs production before royalties for the six months ended June 30, 2026 averaged 1,223,625 bbl/d, an increase of 12% from 1,096,049 bbl/d for the six months ended June 30, 2025. The Company achieved record quarterly crude oil and NGLs production before royalties during the second quarter of 2026 of 1,248,889 bbl/d, an increase of 23% from 1,019,149 bbl/d for the second quarter of 2025 and an increase of 4% from 1,198,079 bbl/d for the first quarter of 2026. The increase in crude oil and NGLs production before royalties for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected high utilization in the Oil Sands Mining and Upgrading segment, the AOSP asset swap completed in the fourth quarter of 2025, and the impact of the turnaround at Scotford in the second quarter of 2025. The increase also reflected strong production in the North America Exploration and Production segment resulting from acquisitions completed in 2025 and 2026, and strong drilling results. The increase in crude oil and NGLs production before royalties for the second quarter of 2026 from the first quarter of 2026 primarily reflected high utilization in the Oil Sands Mining and Upgrading segment, and acquisitions completed in 2026 in the North America Exploration and Production segment.

Annual crude oil and NGLs production before royalties for 2026 is now targeted to average between 1,204,000 bbl/d and 1,243,000 bbl/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties for the six months ended June 30, 2026 averaged 2,619 MMcf/d, an increase of 8% from 2,429 MMcf/d for the six months ended June 30, 2025. Natural gas production before royalties for the second quarter of 2026 averaged 2,567 MMcf/d, an increase of 7% from 2,407 MMcf/d for the second quarter of 2025 and a decrease of 4% from 2,670 MMcf/d for the first quarter of 2026. The increase in natural gas production before royalties for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected production associated with the light crude oil and liquids-rich natural gas acquisitions completed in 2025 and 2026, partially offset by natural field declines. The decrease in natural gas production before royalties for the second quarter of 2026 from the first quarter of 2026 primarily reflected planned maintenance activities and natural field declines, partially offset by the acquisitions completed in the first and second quarters of 2026.

Annual natural gas production before royalties for 2026 is now targeted to average between 2,595 MMcf/d and 2,635 MMcf/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the six months ended June 30, 2026 averaged 608,534 bbl/d, an increase of 10% from 553,482 bbl/d for the six months ended June 30, 2025. The Company achieved record quarterly North America crude oil and NGLs production before royalties during the second quarter of 2026 of 613,745 bbl/d, an increase of 12% from 545,811 bbl/d for the second quarter of 2025 and comparable with 603,265 bbl/d for the first quarter of 2026. The increase in North America crude oil and NGLs production before royalties for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected the acquisitions completed in 2025 and 2026, and strong drilling results.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 275,607 bbl/d for the second quarter of 2026, comparable with 274,789 bbl/d for the second quarter of 2025 and 274,674 bbl/d for the first quarter of 2026. Changes in thermal in situ production for the second quarter of 2026 from the comparable periods primarily reflected strong production from thermal pad additions at Pike, offset by the cyclical nature of Primrose, and the impact of planned maintenance activities at Jackfish in the second quarter of 2026.

Pelican Lake heavy crude oil production before royalties for the second quarter of 2026 averaged 44,053 bbl/d, comparable with 43,078 bbl/d for the second quarter of 2025 and an increase of 9% from 40,548 bbl/d for the first quarter of 2026 reflecting Pelican Lake's long life low decline production, and strong results at Driftwood.

North America natural gas production before royalties for the six months ended June 30, 2026 averaged 2,616 MMcf/d, an increase of 8% from 2,417 MMcf/d for the six months ended June 30, 2025. Natural gas production before royalties averaged 2,563 MMcf/d for the second quarter of 2026, an increase of 7% from 2,398 MMcf/d for the second quarter of 2025 and a decrease of 4% from 2,668 MMcf/d for the first quarter of 2026. The increase in natural gas production before royalties for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected production associated with the light crude oil and liquids-rich natural gas acquisitions completed in 2025 and 2026, partially offset by natural field declines. The decrease in natural gas production before royalties for the second quarter of 2026 from the first quarter of 2026 primarily reflected planned maintenance activities and natural field declines, partially offset by the acquisitions completed in the first and second quarters of 2026.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the six months ended June 30, 2026 averaged 606,452 bbl/d, an increase of 15% from 529,099 bbl/d for the six months ended June 30, 2025. The Company achieved record quarterly SCO production before royalties during the second quarter of 2026 of 624,754 bbl/d, an increase of 35% from 463,808 bbl/d for the second quarter of 2025 and an increase of 6% from 587,946 bbl/d for the first quarter of 2026. The increase in SCO production before royalties for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected high utilization, the AOSP asset swap completed in the fourth quarter of 2025, and the impact of the turnaround at Scotford in the second quarter of 2025. The increase in SCO production before royalties for the second quarter of 2026 from the first quarter of 2026 primarily reflected high utilization during the second quarter.

International – Exploration and Production

International crude oil and NGLs production before royalties for the six months ended June 30, 2026 averaged 8,639 bbl/d, a decrease of 36% from 13,468 bbl/d for the six months ended June 30, 2025. International crude oil and NGLs production before royalties for the second quarter of 2026 averaged 10,390 bbl/d, an increase of 9% from 9,530 bbl/d for the second quarter of 2025 and an increase of 51% from 6,868 bbl/d for the first quarter of 2026. The decrease in International crude oil and NGLs production before royalties for the six months ended June 30, 2026 from the six months ended June 30, 2025 primarily reflected planned North Sea abandonments conducted as part of the previously announced decommissioning plans. The increase in crude oil and NGLs production before royalties for the second quarter of 2026 from the second quarter of 2025 primarily reflected the completion of planned maintenance on the FPSO at Baobab, which was returned to service in June 2026. The increase in crude oil and NGLs production before royalties for the second quarter of 2026 from the first quarter of 2026 primarily reflected the completion of maintenance activities on the FPSO at Baobab, and in the North Sea.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
Realized price ⁽²⁾	\$ 105.11	\$ 76.02	\$ 69.58	\$ 90.77	\$ 74.82
Transportation ⁽³⁾	7.14	7.05	7.65	7.09	7.01
Realized price, net of transportation ⁽²⁾	97.97	68.97	61.93	83.68	67.81
Royalties ⁽⁴⁾	19.79	13.41	9.20	16.65	11.83
Production expense ⁽⁵⁾	14.99	13.54	14.03	14.28	14.90
Netback ⁽²⁾	\$ 63.19	\$ 42.02	\$ 38.70	\$ 52.75	\$ 41.08
Natural gas (\$/Mcf) ⁽¹⁾					
Realized price ⁽⁶⁾	\$ 2.05	\$ 3.32	\$ 2.58	\$ 2.69	\$ 2.86
Transportation ⁽³⁾	0.60	0.58	0.59	0.59	0.61
Realized price, net of transportation	1.45	2.74	1.99	2.10	2.25
Royalties ⁽⁴⁾	0.07	0.15	0.08	0.11	0.10
Production expense ⁽⁵⁾	1.28	1.24	1.11	1.26	1.15
Netback ⁽⁷⁾	\$ 0.10	\$ 1.35	\$ 0.80	\$ 0.73	\$ 1.00
Barrels of oil equivalent (\$/BOE) ⁽¹⁾					
Realized price ⁽²⁾	\$ 68.17	\$ 52.88	\$ 47.17	\$ 60.54	\$ 51.11
Transportation ⁽³⁾	5.70	5.54	5.94	5.62	5.63
Realized price, net of transportation ⁽²⁾	62.47	47.34	41.23	54.92	45.48
Royalties ⁽⁴⁾	12.02	8.23	5.58	10.13	7.19
Production expense ⁽⁵⁾	12.00	10.96	10.95	11.48	11.60
Netback ⁽²⁾	\$ 38.45	\$ 28.15	\$ 24.70	\$ 33.31	\$ 26.69

(1) For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

(2) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Calculated as transportation expense divided by respective sales volumes.

(4) Calculated as royalties divided by respective sales volumes.

(5) Calculated as production expense divided by respective sales volumes.

(6) Calculated as natural gas sales divided by natural gas sales volumes.

(7) Natural gas netbacks exclude NGLs netbacks derived from the Company's liquids-rich natural gas plays.

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America ⁽²⁾	\$ 104.77	\$ 75.91	\$ 69.30	\$ 90.48	\$ 73.95
International average ⁽³⁾	\$ 126.82	\$ 91.81	\$ 91.00	\$ 115.84	\$ 103.58
North Sea ⁽³⁾	\$ 122.97	\$ 91.81	\$ 90.63	\$ 111.52	\$ 102.41
Offshore Africa ⁽³⁾	\$ 141.00	\$ —	\$ 95.92	\$ 141.00	\$ 105.85
Crude oil and NGLs average ⁽²⁾	\$ 105.11	\$ 76.02	\$ 69.58	\$ 90.77	\$ 74.82
Natural gas (\$/Mcf) ^{(1) (3)}					
North America	\$ 2.03	\$ 3.32	\$ 2.54	\$ 2.68	\$ 2.80
International average	\$ 13.62	\$ 11.26	\$ 11.71	\$ 12.82	\$ 13.40
North Sea	\$ 13.29	\$ 11.26	\$ 10.00	\$ 12.32	\$ 13.86
Offshore Africa	\$ 14.02	\$ —	\$ 12.47	\$ 14.02	\$ 13.20
Natural gas average	\$ 2.05	\$ 3.32	\$ 2.58	\$ 2.69	\$ 2.86
Average (\$/BOE) ^{(1) (2)}	\$ 68.17	\$ 52.88	\$ 47.17	\$ 60.54	\$ 51.11

(1) For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

(2) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Calculated as crude oil and NGLs sales, and natural gas sales divided by respective sales volumes.

North America

North America realized crude oil and NGLs prices increased 22% to average \$90.48 per bbl for the six months ended June 30, 2026 from \$73.95 per bbl for the six months ended June 30, 2025. North America realized crude oil and NGLs prices averaged \$104.77 per bbl for the second quarter of 2026, an increase of 51% from \$69.30 per bbl for the second quarter of 2025 and an increase of 38% from \$75.91 per bbl for the first quarter of 2026. The increase in North America realized crude oil and NGLs prices per bbl for the three and six months ended June 30, 2026 from the comparable periods primarily reflected higher WTI benchmark pricing. Realized crude oil and NGLs pricing is also directly impacted by fluctuations in foreign exchange rates as sales prices are primarily denominated with reference to US dollar benchmarks. The Company continues to focus on its crude oil blending and marketing strategy and in the second quarter of 2026 contributed approximately 239,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 4% to average \$2.68 per Mcf for the six months ended June 30, 2026 from \$2.80 per Mcf for the six months ended June 30, 2025. North America realized natural gas prices decreased 20% to average \$2.03 per Mcf for the second quarter of 2026 from \$2.54 per Mcf for the second quarter of 2025 and decreased 39% from \$3.32 per Mcf for the first quarter of 2026. The decrease in North America realized natural gas prices per Mcf for the three and six months ended June 30, 2026 from the comparable periods primarily reflected lower AECO benchmark pricing. The decrease for the second quarter of 2026 from the comparable periods also reflected lower export pricing.

The prices received in the North America Exploration and Production segment by product type were as follows:

(Quarterly average)	Three Months Ended		
	Jun 30 2026	Mar 31 2026	Jun 30 2025
Wellhead Price ⁽¹⁾			
Light and medium crude oil and NGLs (\$/bbl)	\$ 95.30	\$ 73.85	\$ 63.96
Pelican Lake heavy crude oil (\$/bbl)	\$ 108.92	\$ 78.70	\$ 73.94
Primary heavy crude oil (\$/bbl)	\$ 109.09	\$ 76.54	\$ 72.88
Thermal bitumen (\$/bbl)	\$ 109.76	\$ 76.72	\$ 70.13
Natural gas (\$/Mcf)	\$ 2.03	\$ 3.32	\$ 2.54

(1) Amounts expressed on a per unit basis are based on sales volumes of the respective product type.

International

International realized crude oil and NGLs prices increased 12% to average \$115.84 per bbl for the six months ended June 30, 2026 from \$103.58 per bbl for the six months ended June 30, 2025. International realized crude oil and NGLs prices increased 39% to average \$126.82 per bbl for the second quarter of 2026 from \$91.00 per bbl for the second quarter of 2025 and increased 38% from \$91.81 per bbl for the first quarter of 2026. Realized crude oil and NGLs prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, prevailing Brent benchmark prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America	\$ 20.07	\$ 13.51	\$ 9.31	\$ 16.82	\$ 12.14
International average	\$ 1.52	\$ 0.08	\$ 0.45	\$ 1.07	\$ 1.65
North Sea	\$ 0.17	\$ 0.08	\$ 0.17	\$ 0.14	\$ 0.15
Offshore Africa	\$ 6.47	\$ —	\$ 4.19	\$ 6.47	\$ 4.59
Crude oil and NGLs average	\$ 19.79	\$ 13.41	\$ 9.20	\$ 16.65	\$ 11.83
Natural gas (\$/Mcf) ⁽¹⁾					
North America	\$ 0.07	\$ 0.15	\$ 0.08	\$ 0.11	\$ 0.09
Offshore Africa	\$ 0.64	\$ —	\$ 0.57	\$ 0.64	\$ 0.61
Natural gas average	\$ 0.07	\$ 0.15	\$ 0.08	\$ 0.11	\$ 0.10
Average (\$/BOE) ⁽¹⁾	\$ 12.02	\$ 8.23	\$ 5.58	\$ 10.13	\$ 7.19

(1) Calculated as royalties divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

North America

North America crude oil and NGLs and natural gas royalties for the three and six months ended June 30, 2026 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates⁽¹⁾ averaged approximately 19% of product sales for the six months ended June 30, 2026 compared with 16% of product sales for the six months ended June 30, 2025. Crude oil and NGLs royalty rates averaged approximately 19% of product sales for the second quarter of 2026 compared with 13% for the second quarter of 2025 and 18% for the first quarter of 2026. The increase in royalty rates for the three and six months ended June 30, 2026 from the comparable periods primarily reflected higher benchmark pricing.

Natural gas royalty rates averaged approximately 4% of product sales for the six months ended June 30, 2026 compared with 3% of product sales for the six months ended June 30, 2025. Natural gas royalty rates averaged approximately 3% of product sales for the second quarter of 2026 compared with 3% for the second quarter of 2025 and 5% for the first quarter of 2026. The fluctuations in royalty rates for the three and six months ended June 30, 2026 from comparable periods primarily reflected prevailing benchmark pricing.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital expenditures and production expenses, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 5% for the six months ended June 30, 2026 compared with 4% of product sales for the six months ended June 30, 2025. Royalty rates as a percentage of product sales averaged approximately 5% for the second quarter of 2026 compared with 5% of product sales for the second quarter of 2025. There was no royalty expense recognized in the first quarter of 2026 due to the absence of product sales. Royalty rates as a percentage of product sales reflected the timing of liftings, and the status of payout in the various fields.

(1) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America	\$ 13.05	\$ 13.03	\$ 11.89	\$ 13.04	\$ 12.28
International average	\$ 141.98	\$ 85.18	\$ 175.70	\$ 124.16	\$ 101.16
North Sea	\$ 140.05	\$ 85.18	\$ 186.50	\$ 119.88	\$ 138.54
Offshore Africa	\$ 149.08	\$ —	\$ 29.38	\$ 149.08	\$ 28.31
Crude oil and NGLs average	\$ 14.99	\$ 13.54	\$ 14.03	\$ 14.28	\$ 14.90
Natural gas (\$/Mcf) ⁽¹⁾					
North America	\$ 1.25	\$ 1.23	\$ 1.07	\$ 1.24	\$ 1.11
International average	\$ 16.93	\$ 7.60	\$ 12.20	\$ 13.78	\$ 9.37
North Sea	\$ 12.44	\$ 7.60	\$ 12.78	\$ 10.12	\$ 11.42
Offshore Africa	\$ 22.46	\$ —	\$ 11.94	\$ 22.46	\$ 8.51
Natural gas average	\$ 1.28	\$ 1.24	\$ 1.11	\$ 1.26	\$ 1.15
Average (\$/BOE) ⁽¹⁾	\$ 12.00	\$ 10.96	\$ 10.95	\$ 11.48	\$ 11.60

(1) Calculated as production expense divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A. For natural gas sales volumes, refer to the 'Daily Production, before royalties' section of this MD&A.

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2026 averaged \$13.04 per bbl, an increase of 6% from \$12.28 per bbl for the six months ended June 30, 2025. North America crude oil and NGLs production expense for the second quarter of 2026 averaged \$13.05 per bbl, an increase of 10% from \$11.89 per bbl for the second quarter of 2025 and comparable with \$13.03 per bbl for the first quarter of 2026. The increase in crude oil and NGLs production expense per bbl for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected higher NGL processing costs resulting from acquisitions completed in the second half of 2025.

North America natural gas production expense for the six months ended June 30, 2026 averaged \$1.24 per Mcf, an increase of 12% from \$1.11 per Mcf for the six months ended June 30, 2025. North America natural gas production expense for the second quarter of 2026 of \$1.25 per Mcf increased 17% from \$1.07 per Mcf for the second quarter of 2025 and was comparable with \$1.23 per Mcf for the first quarter of 2026. The increase in natural gas production expense per Mcf for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected higher energy and service costs.

International

International crude oil and NGLs production expense for the six months ended June 30, 2026 averaged \$124.16 per bbl, an increase of 23% from \$101.16 per bbl for the six months ended June 30, 2025. International crude oil and NGLs production expense for the second quarter of 2026 of \$141.98 per bbl decreased 19% from \$175.70 per bbl for the second quarter of 2025 and increased 67% from \$85.18 per bbl for the first quarter of 2026. The fluctuations in crude oil and NGLs production expense per bbl for the three and six months ended June 30, 2026 from the comparable periods reflected the timing of liftings from various fields that have different cost structures, the impact of foreign exchange, and lower production volumes in the North Sea as the Company continues to execute its previously announced decommissioning plans.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
North America	\$ 1,135	\$ 1,131	\$ 1,085	\$ 2,266	\$ 2,177
North Sea	6	6	33	12	73
Offshore Africa	12	14	13	26	72
Depletion, depreciation and amortization	\$ 1,153	\$ 1,151	\$ 1,131	\$ 2,304	\$ 2,322
\$/BOE ⁽¹⁾	\$ 12.09	\$ 12.12	\$ 12.94	\$ 12.10	\$ 13.11

(1) Calculated as depletion, depreciation and amortization expense divided by sales volumes. For sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Depletion, depreciation and amortization expense for the six months ended June 30, 2026 averaged \$12.10 per BOE, a decrease of 8% from \$13.11 per BOE for the six months ended June 30, 2025. Depletion, depreciation and amortization expense for the second quarter of 2026 averaged \$12.09 per BOE, a decrease of 7% from \$12.94 per BOE for the second quarter of 2025 and comparable with \$12.12 per BOE for the first quarter of 2026. The decrease in depletion, depreciation and amortization expense per BOE for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected higher sales volumes in 2026, combined with changes in North America depletion rates due to changes in reserve estimates at December 31, 2025, and the impact of the Company's international decommissioning activities, partially offset by a higher depletable base following acquisitions completed in 2025 and 2026.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
North America	\$ 54	\$ 55	\$ 53	\$ 109	\$ 106
North Sea	21	20	14	41	28
Offshore Africa	1	2	2	3	4
Asset retirement obligation accretion	\$ 76	\$ 77	\$ 69	\$ 153	\$ 138
\$/BOE ⁽¹⁾	\$ 0.80	\$ 0.80	\$ 0.79	\$ 0.80	\$ 0.78

(1) Calculated as asset retirement obligation accretion divided by sales volumes. For sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for the six months ended June 30, 2026 averaged \$0.80 per BOE, an increase of 3% from \$0.78 per BOE for the six months ended June 30, 2025. Asset retirement obligation accretion expense for the second quarter of 2026 averaged \$0.80 per BOE, comparable with \$0.79 per BOE for the second quarter of 2025 and \$0.80 per BOE for the first quarter of 2026. The increase in asset retirement obligation accretion expense per BOE for the six months ended June 30, 2026 from the six months ended June 30, 2025 primarily reflected the impact of revisions in cost and timing estimates in the North Sea in the second half of 2025, partially offset by higher sales volumes in 2026.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable, and efficient operations, leveraging its technical expertise across the Horizon and AOSP sites, achieving record quarterly SCO production of 624,754 bbl/d during the second quarter of 2026.

REALIZED PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

(\$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Realized SCO sales price ⁽¹⁾	\$ 125.78	\$ 89.68	\$ 87.22	\$ 108.26	\$ 91.88
Bitumen value for royalty purposes ⁽²⁾	\$ 92.72	\$ 66.45	\$ 64.57	\$ 80.17	\$ 69.61
Bitumen royalties ⁽³⁾	\$ 23.38	\$ 15.20	\$ 11.59	\$ 19.41	\$ 15.32
Transportation ⁽⁴⁾	\$ 2.57	\$ 2.60	\$ 3.73	\$ 2.58	\$ 3.44

(1) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(2) Calculated as the quarterly average of the bitumen methodology price.

(3) Calculated as royalties divided by sales volumes.

(4) Calculated as transportation expense divided by sales volumes.

The realized SCO sales price averaged \$108.26 per bbl for the six months ended June 30, 2026, an increase of 18% from \$91.88 per bbl for the six months ended June 30, 2025. The realized SCO sales price averaged \$125.78 per bbl for the second quarter of 2026, an increase of 44% from \$87.22 per bbl for the second quarter of 2025 and an increase of 40% from \$89.68 per bbl for the first quarter of 2026. The increase in realized SCO sales price per bbl for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected higher WTI benchmark pricing, partially offset by changes in the product sales mix between periods. The increase in realized SCO sales price per bbl for the second quarter of 2026 from the first quarter of 2026 primarily reflected higher WTI benchmark pricing, combined with a strong SCO premium over WTI.

The fluctuations in bitumen royalties per bbl in any particular period reflect prevailing bitumen value for royalty purposes, and the impact of sliding scale royalty rates. The increase in bitumen royalties per bbl for the three and six months ended June 30, 2026 from the comparable periods primarily reflected the increase in average bitumen value for royalty purposes.

Transportation expense averaged \$2.58 per bbl for the six months ended June 30, 2026, a decrease of 25% from \$3.44 per bbl for the six months ended June 30, 2025. Transportation expense averaged \$2.57 per bbl for the second quarter of 2026, a decrease of 31% from \$3.73 per bbl for the second quarter of 2025 and comparable with \$2.60 per bbl for the first quarter of 2026. The decrease in transportation expense per bbl for the three and six months ended June 30, 2026 from the comparable periods in 2025 primarily reflected lower transportation expense following the recognition of the Corridor pipeline as a lease asset following the AOSP asset swap in the fourth quarter of 2025.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Production expense, excluding natural gas costs	\$ 1,221	\$ 1,214	\$ 1,085	\$ 2,435	\$ 2,220
Natural gas costs	38	55	35	93	85
Production expense	\$ 1,259	\$ 1,269	\$ 1,120	\$ 2,528	\$ 2,305

(\$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Production expense, excluding natural gas costs ⁽¹⁾	\$ 21.52	\$ 22.70	\$ 25.71	\$ 22.10	\$ 23.03
Natural gas costs ⁽²⁾	0.67	1.03	0.82	0.84	0.88
Production expense ⁽³⁾	\$ 22.19	\$ 23.73	\$ 26.53	\$ 22.94	\$ 23.91
Sales volumes (bbl/d)	623,486	594,042	463,586	608,845	532,434

(1) Calculated as production expense, excluding natural gas costs, divided by sales volumes.

(2) Calculated as natural gas costs divided by sales volumes.

(3) Calculated as production expense divided by sales volumes.

Production expense for the six months ended June 30, 2026 averaged \$22.94 per bbl, a decrease of 4% from \$23.91 per bbl for the six months ended June 30, 2025. Production expense for the second quarter of 2026 averaged \$22.19 per bbl, a decrease of 16% from \$26.53 per bbl for the second quarter of 2025 and a decrease of 6% from \$23.73 per bbl for the first quarter of 2026. The decrease in production expense per bbl for the six months ended June 30, 2026 from the six months ended June 30, 2025 primarily reflected higher sales volumes in 2026, partially offset by higher energy costs, including diesel costs, and unplanned maintenance activities in the first quarter of 2026. The decrease in production expense per bbl for the second quarter of 2026 from the second quarter of 2025 primarily reflected higher sales volumes in 2026, partially offset by higher energy costs, including diesel costs. The decrease in production expense per bbl for the second quarter of 2026 from the first quarter of 2026 primarily reflected higher sales volumes in the second quarter.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Depletion, depreciation and amortization	\$ 744	\$ 722	\$ 630	\$ 1,466	\$ 1,305
\$/bbl ⁽¹⁾	\$ 13.11	\$ 13.50	\$ 14.96	\$ 13.30	\$ 13.55

(1) Calculated as depletion, depreciation and amortization expense divided by sales volumes.

Depletion, depreciation and amortization expense for the six months ended June 30, 2026 averaged \$13.30 per bbl, comparable with \$13.55 per bbl for the six months ended June 30, 2025. Depletion, depreciation and amortization expense for the second quarter of 2026 of \$13.11 per bbl decreased 12% from \$14.96 per bbl for the second quarter of 2025 and decreased 3% from \$13.50 per bbl for the first quarter of 2026. The decrease in depletion, depreciation and amortization expense per bbl for the second quarter of 2026 from the second quarter of 2025 primarily reflected the impact of higher sales volumes in 2026, partially offset by a higher depletable base due to the gain recognized on the AOSP mine assets and the recognition of the Corridor pipeline as a lease asset, both arising from the AOSP asset swap in the fourth quarter of 2025. The decrease in depletion, depreciation and amortization expense per bbl for the second quarter of 2026 from the first quarter of 2026 primarily reflected the impact of higher sales volumes in the second quarter.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Asset retirement obligation accretion	\$ 22	\$ 21	\$ 21	\$ 43	\$ 43
\$/bbl ⁽¹⁾	\$ 0.38	\$ 0.40	\$ 0.51	\$ 0.39	\$ 0.45

(1) Calculated as asset retirement obligation accretion divided by sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for the six months ended June 30, 2026 of \$0.39 per bbl decreased 13% from \$0.45 per bbl for the six months ended June 30, 2025. Asset retirement obligation accretion expense for the second quarter of 2026 of \$0.38 per bbl decreased 25% from \$0.51 per bbl for the second quarter of 2025 and decreased 5% from \$0.40 per bbl for the first quarter of 2026. The decrease in asset retirement obligation accretion expense per bbl for the three and six months ended June 30, 2026 from the comparable periods primarily reflected the impact of higher sales volumes.

MIDSTREAM AND REFINING

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Product sales					
Midstream activities	\$ 23	\$ 23	\$ 22	\$ 46	\$ 44
NWRP, refined product sales and other	346	277	137	623	358
Segmented revenue	369	300	159	669	402
Less:					
NWRP, refining toll	85	57	61	142	129
Midstream activities	8	6	5	14	10
Production expense	93	63	66	156	139
NWRP, feedstock costs	241	170	105	411	277
Transportation expense	4	4	31	8	35
Depreciation	5	4	4	9	8
Segmented earnings (loss)	\$ 26	\$ 59	\$ (47)	\$ 85	\$ (57)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose, and the Company's 50% equity investment in North West Redwater Partnership ("NWRP").

NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 bbl/d. The refinery's processing design capacity is approximately 50,000 bbl/d of bitumen feedstock, including 12,500 bbl/d of bitumen feedstock for the Company (25% toll payer) and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. Bitumen feedstock throughput can exceed design capacity when asset reliability and operational performance support higher processing rates. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058. Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the second quarter of 2026, production of ultra-low sulphur diesel and other refined products averaged 92,748 BOE/d (23,187 BOE/d to the Company) (three months ended March 31, 2026 – 94,351 BOE/d; 23,588 BOE/d to the Company; three months ended June 30, 2025 – 60,549 BOE/d; 15,137 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at June 30, 2026, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$405 million (December 31, 2025 – \$496 million). For the three months ended June 30, 2026, the Company's recovery of its share of unrecognized equity losses was \$66 million (three months ended March 31, 2026 – recovery of unrecognized equity losses of \$25 million; three months ended June 30, 2025 – recovery of unrecognized equity losses of \$24 million; six months ended June 30, 2026 – recovery of unrecognized equity losses of \$91 million; six months ended June 30, 2025 – recovery of unrecognized equity losses of \$5 million).

ADMINISTRATION EXPENSE

(\$ millions, except per BOE amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Administration expense	\$ 159	\$ 154	\$ 151	\$ 313	\$ 303
\$/BOE ⁽¹⁾	\$ 1.04	\$ 1.04	\$ 1.17	\$ 1.04	\$ 1.11
Sales volumes (BOE/d) ⁽²⁾	1,672,106	1,649,558	1,423,321	1,660,894	1,510,917

(1) Calculated as administration expense divided by sales volumes.

(2) Total Company sales volumes.

Administration expense for the six months ended June 30, 2026 of \$1.04 per BOE decreased 6% from \$1.11 per BOE for the six months ended June 30, 2025. Administration expense for the second quarter of 2026 of \$1.04 per BOE decreased 11% from \$1.17 per BOE for the second quarter of 2025 and was comparable with \$1.04 per BOE for the first quarter of 2026. The decrease in administration expense per BOE for the six months ended June 30, 2026 from the six months ended June 30, 2025 primarily reflected higher sales volumes, partially offset by higher corporate costs and lower overhead recoveries. The decrease in administration expense per BOE for the second quarter of 2026 from the second quarter of 2025 primarily reflected higher sales volumes.

SHARE-BASED COMPENSATION

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Share-based compensation (recovery) expense	\$ (196)	\$ 644	\$ 8	\$ 448	\$ 34

The Company's Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The Performance Share Unit ("PSU") Plan provides certain executive employees of the Company with the right to receive a cash payment; the amount of which is determined with reference to the value of the Company's shares, by individual employee performance, and the extent to which certain other performance measures are met.

The Company recognized \$448 million of share-based compensation expense for the six months ended June 30, 2026 primarily as a result of changes in the Company's share price, the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, and the impact of vested stock options exercised or surrendered during the period.

INTEREST AND OTHER FINANCING EXPENSE

(\$ millions, except effective interest rate)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Interest and other financing expense	\$ 238	\$ 318	\$ 238	\$ 556	\$ 496
Less: Interest (income) and other expense ⁽¹⁾	(20)	64	(7)	44	(13)
Interest expense on long-term debt and lease liabilities ⁽¹⁾	\$ 258	\$ 254	\$ 245	\$ 512	\$ 509
Average current and long-term debt ⁽²⁾	\$ 17,500	\$ 17,445	\$ 17,552	\$ 17,473	\$ 18,349
Average lease liabilities ⁽²⁾	3,037	3,077	1,382	3,057	1,402
Average long-term debt and lease liabilities ⁽²⁾	\$ 20,537	\$ 20,522	\$ 18,934	\$ 20,530	\$ 19,751
Average effective interest rate ^{(3) (4)}	4.9%	4.9%	5.1%	4.9%	5.1%
Interest and other financing expense (\$/BOE) ⁽⁵⁾	\$ 1.57	\$ 2.14	\$ 1.84	\$ 1.85	\$ 1.81
Sales volumes (BOE/d) ⁽⁶⁾	1,672,106	1,649,558	1,423,321	1,660,894	1,510,917

(1) Item is a component of interest and other financing expense.

(2) The average of current and long-term debt and lease liabilities outstanding during the respective period.

(3) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance.

(4) Calculated as the average interest expense on long-term debt and lease liabilities divided by the average long-term debt and lease liabilities balance. The Company presents its average effective interest rate for financial statement users to evaluate the Company's average cost of debt borrowings.

(5) Calculated as interest and other financing expense divided by sales volumes.

(6) Total Company sales volumes.

Interest and other financing expense for the six months ended June 30, 2026 averaged \$1.85 per BOE, comparable with \$1.81 per BOE for the six months ended June 30, 2025. Interest and other financing expense for the second quarter of 2026 decreased 15% to \$1.57 per BOE from \$1.84 per BOE for the second quarter of 2025 and decreased 27% from \$2.14 per BOE for the first quarter of 2026. The decrease in interest and other financing expense per BOE for the second quarter of 2026 from the second quarter of 2025 primarily reflected higher sales volumes in 2026, partially offset by higher average lease liabilities following the recognition of the Corridor pipeline in the fourth quarter of 2025. The decrease in interest and other financing expense per BOE for the second quarter of 2026 from the first quarter of 2026 primarily reflected the impact of accrued interest in the North Sea in the first quarter, combined with higher sales volumes in the second quarter.

The Company's average effective interest rate for the three and six months ended June 30, 2026 averaged 4.9%, a decrease from 5.1% for the comparable periods in 2025, reflecting interest rates on the medium-term note issuances in December 2025, combined with a lower effective interest rate on higher average lease liabilities.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate, and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Foreign currency forward contracts	\$ 49	\$ 43	\$ (115)	\$ 92	\$ (135)
Foreign currency put options	—	—	27	—	23
Natural gas financial contracts ^{(1) (2)}	3	2	(1)	5	(4)
Net realized loss (gain)	52	45	(89)	97	(116)
Foreign currency forward contracts	(4)	1	(19)	(3)	(5)
Foreign currency put options	—	—	2	—	—
Natural gas financial contracts ^{(1) (2)}	(2)	3	13	1	4
Natural gas embedded derivative ⁽³⁾	(2)	312	(11)	310	(11)
Net unrealized (gain) loss	(8)	316	(15)	308	(12)
Net loss (gain)	\$ 44	\$ 361	\$ (104)	\$ 405	\$ (128)

(1) In the third quarter of 2025, the Company entered into fixed price financial contracts to buy 25,000 MMBtu/d of natural gas at US\$2.16 AECO for the period of January to December 2026.

(2) In the fourth quarter of 2024, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US\$1.47 AECO, and 25,000 MMBtu/d of natural gas at US\$1.82 AECO for the period of January to December 2025.

(3) In the second quarter of 2025, the Company entered into a long-term natural gas supply agreement containing an embedded derivative. Further details are disclosed in note 15 to the financial statements.

The Company recorded a net realized risk management loss of \$97 million for the six months ended June 30, 2026 and a net realized risk management loss of \$52 million for the second quarter of 2026.

The Company recorded a net unrealized loss of \$308 million (\$237 million after tax of \$71 million) on its risk management activities for the six months ended June 30, 2026 and a net unrealized gain of \$8 million (\$6 million after tax of \$2 million) for the second quarter of 2026 (six months ended June 30, 2025 – unrealized gain of \$12 million (\$10 million after tax of \$2 million); three months ended March 31, 2026 – unrealized loss of \$316 million (\$243 million after tax of \$73 million); three months ended June 30, 2025 – unrealized gain of \$15 million (\$12 million after tax of \$3 million)).

Further details related to outstanding derivative financial instruments as at June 30, 2026 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Net realized loss (gain)	\$ 24	\$ (23)	\$ (142)	\$ 1	\$ 100
Net unrealized loss (gain)	157	285	(661)	442	(946)
Net loss (gain) ⁽¹⁾	\$ 181	\$ 262	\$ (803)	\$ 443	\$ (846)

(1) Amounts are reported net of derivative financial instruments designated as cash flow hedges.

The net realized foreign exchange loss for the six months ended June 30, 2026 primarily reflected exchange rate fluctuations on the settlement of US dollar debt and working capital items denominated in US dollars.

The net unrealized foreign exchange loss for the six months ended June 30, 2026 primarily reflected the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at June 30, 2026 was US\$0.7040 (March 31, 2026 – US\$0.7166; June 30, 2025 – US\$0.7341).

INCOME TAXES

(\$ millions, except effective tax rates)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
North America ⁽¹⁾	\$ 1,164	\$ 671	\$ 529	\$ 1,835	\$ 1,098
North Sea	(46)	(53)	(45)	(99)	(71)
Offshore Africa	1	—	—	1	5
Current PRT – North Sea	(49)	(65)	(49)	(114)	(88)
Other taxes	3	2	3	5	5
Current income tax	1,073	555	438	1,628	949
Deferred corporate income tax	275	(59)	(106)	216	13
Deferred PRT – North Sea	37	(114)	18	(77)	27
Deferred income tax	312	(173)	(88)	139	40
Income tax	\$ 1,385	\$ 382	\$ 350	\$ 1,767	\$ 989
Earnings before taxes	\$ 5,888	\$ 1,730	\$ 2,809	\$ 7,618	\$ 5,906
Effective tax rate on net earnings ⁽²⁾	24%	22%	12%	23%	17%

(\$ millions, except effective tax rates)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Income tax	\$ 1,385	\$ 382	\$ 350	\$ 1,767	\$ 989
Tax effect on non-operating items ⁽³⁾	(14)	126	(1)	112	4
Current PRT – North Sea	49	65	49	114	88
Deferred PRT – North Sea	(37)	114	(18)	77	(27)
Other taxes	(3)	(2)	(3)	(5)	(5)
Effective tax on adjusted net earnings	\$ 1,380	\$ 685	\$ 377	\$ 2,065	\$ 1,049
Adjusted net earnings from operations ⁽⁴⁾	\$ 4,568	\$ 2,446	\$ 1,496	\$ 7,014	\$ 3,932
Adjusted net earnings from operations, before taxes	\$ 5,948	\$ 3,131	\$ 1,873	\$ 9,079	\$ 4,981
Effective tax rate on adjusted net earnings from operations ^{(5) (6)}	23%	22%	20%	23%	21%

(1) Includes North America Exploration and Production, Oil Sands Mining and Upgrading, and Midstream and Refining segments.

(2) Calculated as total of current and deferred income tax divided by earnings before taxes.

(3) Includes the net income tax effect on PSUs, certain stock options, and unrealized risk management.

(4) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(5) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance.

(6) Calculated as effective tax on adjusted net earnings divided by adjusted net earnings from operations, before taxes. The Company presents its effective tax rate on adjusted net earnings from operations for financial statement users to evaluate the Company's effective tax rate on its core business activities.

The effective tax rate on net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2026 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

The current and deferred corporate income tax and the current and deferred PRT in the North Sea for the three and six months ended June 30, 2026 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the decommissioning activities in the North Sea.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's reported results of operations, financial position or liquidity.

NET CAPITAL EXPENDITURES ^{(1) (2)}

	Three Months Ended			Six Months Ended	
(\$ millions)	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	\$ 4	\$ 23	\$ 5	\$ 27	\$ 24
Net property acquisitions	21	63	46	84	33
Total Exploration and Evaluation Assets	25	86	51	111	57
Property, Plant and Equipment					
Net property acquisitions	741	710	178	1,451	209
Well drilling, completion and equipping	713	634	558	1,347	1,094
Production and related facilities	405	379	407	784	797
Other	17	(135)	16	(118)	19
Total Property, Plant and Equipment	1,876	1,588	1,159	3,464	2,119
Total Exploration and Production	1,901	1,674	1,210	3,575	2,176
Oil Sands Mining and Upgrading					
Project costs	61	44	96	105	151
Sustaining capital	404	285	406	689	622
Turnaround costs	22	11	174	33	220
Other	3	2	2	5	4
Total Oil Sands Mining and Upgrading	490	342	678	832	997
Midstream and Refining	2	1	2	3	4
Head Office	12	11	25	23	41
Net capital expenditures	\$ 2,405	\$ 2,028	\$ 1,915	\$ 4,433	\$ 3,218
By Segment					
North America	\$ 1,754	\$ 1,529	\$ 1,110	\$ 3,283	\$ 1,946
North Sea	3	2	8	5	11
Offshore Africa	144	143	92	287	219
Oil Sands Mining and Upgrading	490	342	678	832	997
Midstream and Refining	2	1	2	3	4
Head Office	12	11	25	23	41
Net capital expenditures	\$ 2,405	\$ 2,028	\$ 1,915	\$ 4,433	\$ 3,218
Abandonment expenditures	\$ 182	\$ 247	\$ 193	\$ 429	\$ 381

(1) Net capital expenditures exclude the impact of lease assets and fair value adjustments.

(2) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production expenses.

Net capital expenditures were \$4,433 million for the six months ended June 30, 2026 compared with \$3,218 million for the six months ended June 30, 2025. Net capital expenditures were \$2,405 million for the second quarter of 2026 compared with \$1,915 million for the second quarter of 2025 and \$2,028 million for the first quarter of 2026. In addition, the Company reported abandonment expenditures of \$429 million for the six months ended June 30, 2026 compared with \$381 million for the six months ended June 30, 2025. Abandonment expenditures were \$182 million for the second quarter of 2026 compared with \$193 million for the second quarter of 2025 and \$247 million for the first quarter of 2026.

2026 Capital Budget

On December 16, 2025, the Company announced its 2026 operating capital budget⁽¹⁾ targeted at approximately \$6,300 million. With this capital, the Company is targeting production growth in 2026 of approximately 3% from 2025, as it invests in short- and medium-term production, while commencing front-end engineering and design on potential additional medium- and long-term value creation opportunities. In addition, the Company targets approximately \$125 million of capital related to carbon capture projects. The Company targets \$993 million in abandonment expenditures for 2026, before recoveries, related to its abandonment and reclamation programs in North America and the North Sea. During the first quarter of 2026, the Company revised its operating capital forecast to \$5,990 million and net acquisition capital to \$765 million, and increased its production guidance to between 1,615,000 BOE/d and 1,665,000 BOE/d. Subsequent to the second quarter of 2026, the Company maintained its operating capital forecast at \$5,990 million, revised net acquisition capital to \$1,526 million, and increased its production guidance to between 1,637,000 BOE/d and 1,682,000 BOE/d.

Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns, and the balancing of project risks and time horizons. The 2026 capital budget constitutes forward-looking statements and is based on net capital expenditures (Non-GAAP Financial Measure). Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Drilling Activity^{(1) (2)}

	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
(number of net wells)					
Net successful crude oil wells ⁽³⁾	118	113	81	231	155
Net successful natural gas wells	23	24	22	47	41
Dry wells	—	1	—	1	1
Total	141	138	103	279	197
Success rate	100%	99%	100%	99%	99%

(1) Includes drilling activity for North America and International segments.

(2) Excludes stratigraphic and service wells.

(3) Includes bitumen wells.

North America

During the second quarter of 2026, the Company drilled 23 net natural gas wells, 39 net primary heavy crude oil wells, 13 net Pelican Lake heavy crude oil wells, 38 net thermal bitumen wells, and 28 net light crude oil wells.

(1) Forward-looking non-GAAP Financial Measure. The operating capital budget is based on net capital expenditures (Non-GAAP Financial Measure). Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A for more details on net capital expenditures.

LIQUIDITY AND CAPITAL RESOURCES

(\$ millions, except ratios)	Jun 30 2026	Mar 31 2026	Dec 31 2025	Jun 30 2025
Adjusted working capital ⁽¹⁾	\$ 2,222	\$ 289	\$ 42	\$ 102
Long-term debt, net ⁽²⁾	\$ 14,526	\$ 16,153	\$ 15,944	\$ 16,979
Shareholders' equity	\$ 46,796	\$ 44,638	\$ 44,366	\$ 41,298
Debt to book capitalization ⁽²⁾	23.7%	26.6%	26.4%	29.1%
After-tax return on average capital employed ⁽³⁾	20.6%	17.5%	19.5%	16.3%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Capital Management Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

(3) Non-GAAP Ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

As at June 30, 2026, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities, and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt are dependent on factors discussed in the 'Business Environment' section of this MD&A and in the 'Risks and Uncertainties' section of the Company's annual MD&A for the year ended December 31, 2025. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings, as determined by independent rating agencies and market conditions.

The Company continues to believe its internally generated cash flows from operating activities, supported by its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short-, medium-, and long-term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers, and joint venture partners on a regular basis and, where appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments, and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
 - During the first quarter of 2026, the Company cancelled the \$140 million portion of its \$2,565 million revolving syndicated credit facility, maturing June 2027, reducing the capacity to \$2,425 million, with a maturity of June 2029.
 - Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.
 - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US\$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
 - In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at June 30, 2026, the Company had \$1,350 million remaining on its base shelf prospectus.
 - In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US\$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at June 30, 2026, the Company had US\$3,003 million remaining on its base shelf prospectus.

As at June 30, 2026, the Company had undrawn bank credit facilities of \$5,356 million, and a fully drawn non-revolving term credit facility of \$4,000 million. Including cash and cash equivalents, the Company had approximately \$7,974 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

Long-term debt, net was \$14,526 million as at June 30, 2026 (December 31, 2025 – \$15,944 million), resulting in a debt to book capitalization ratio of 23.7% (December 31, 2025 – 26.4%). The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at June 30, 2026, the Company was in compliance with this covenant.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at June 30, 2026 are discussed in note 8 to the financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of commodity put options is in addition to the above parameters.

As at June 30, 2026, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

		Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt ⁽¹⁾	\$	2,214	\$ 4,320	\$ 2,876	\$ 7,814
Other long-term liabilities ^{(2) (3)}	\$	363	\$ 292	\$ 635	\$ 2,230
Interest and other financing expense ⁽⁴⁾	\$	979	\$ 790	\$ 1,842	\$ 3,501

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, \$357 million; one to less than two years, \$292 million; two to less than five years, \$635 million; and thereafter, \$1,755 million.

(3) Includes a gross derivative liability of \$475 million associated with the Company's natural gas embedded derivative. The gross liability is offset by a gross derivative asset of \$108 million, resulting in a net liability of \$367 million.

(4) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at June 30, 2026.

Share Capital

As at June 30, 2026, there were 2,068,840,000 common shares outstanding (December 31, 2025 – 2,081,578,000 common shares) and 56,262,000 stock options outstanding (December 31, 2025 – 54,734,000 stock options). As at August 4, 2026, the Company had 2,061,500,000 common shares outstanding and 55,695,000 stock options outstanding.

On March 4, 2026, the Board of Directors approved a 6% increase in the quarterly dividend to \$0.625 per common share, beginning with the dividend paid on April 7, 2026.

On March 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to \$0.5875 per common share.

The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 10, 2026, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 182,396,564 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2026 and ending March 12, 2027, subject to applicable securities laws.

For the six months ended June 30, 2026, the Company purchased 22,925,000 common shares at a weighted average price of \$61.47 per common share for a total cost, including tax, of \$1,426 million. Retained earnings were reduced by \$1,295 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2026, up to and including August 4, 2026, the Company purchased 7,500,000 common shares at a weighted average price of \$61.44 per common share for a total cost, including tax, of \$470 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at June 30, 2026:

(\$ millions)	Remaining 2026		2027		2028		2029		2030		Thereafter	
Product transportation, purchases, and processing ^{(1) (2)}	\$	1,179	\$	2,317	\$	2,171	\$	2,010	\$	1,849	\$	18,309
North West Redwater Partnership service toll ⁽³⁾	\$	48	\$	96	\$	97	\$	95	\$	95	\$	3,885
Offshore vessels and decommissioning equipment	\$	207	\$	—	\$	—	\$	—	\$	—	\$	—
Field equipment and supplies	\$	94	\$	122	\$	121	\$	24	\$	24	\$	170
Office leases and other	\$	144	\$	66	\$	19	\$	18	\$	18	\$	176

(1) The Company's commitment for its 20-year product transportation agreement ending in 2044 on the TMX pipeline reflects interim tolls approved by the Canada Energy Regulator in the fourth quarter of 2023, and is subject to change pending the approval of final tolls.

(2) During the second quarter of 2026, the Company executed crude oil transportation agreements delivering between 150,000 bbl/d and 165,000 bbl/d of new pipeline capacity to U.S. markets, with service currently expected to commence in the fourth quarter of 2028. These agreements are subject to certain conditions precedent, including a final investment decision by the project proponents and certain regulatory approvals. Accordingly, the related agreements will not be recognized as commitments until the completion of all conditions precedent. The transportation agreements have a term of 20 years and, if all conditions are met, will result in transportation payments of approximately \$500 million to \$550 million annually being added to the Company's commitments.

(3) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is \$1,751 million of interest payable over the 40-year tolling period, ending in 2058.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement, and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions, and judgements in the application of IFRS Accounting Standards that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2025.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the six months ended June 30, 2026 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS Accounting Standards and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below.

Adjusted Net Earnings from Operations

Adjusted net earnings from operations is a non-GAAP financial measure that adjusts net earnings as presented in the Company's consolidated statements of earnings, for non-operating items, net of tax impacts. The Company considers adjusted net earnings from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. A reconciliation for adjusted net earnings from operations is presented below.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Net earnings	\$ 4,503	\$ 1,348	\$ 2,459	\$ 5,851	\$ 4,917
Share-based compensation, net of tax ⁽¹⁾	(184)	591	6	407	28
Unrealized risk management (gain) loss, net of tax ⁽²⁾	(6)	243	(12)	237	(10)
Unrealized foreign exchange loss (gain), net of tax ⁽³⁾	157	285	(661)	442	(946)
Realized foreign exchange loss (gain) on financing activities, net of tax ⁽⁴⁾	98	(21)	(216)	77	23
Gain on acquisition, net of tax ⁽⁵⁾	—	—	(80)	—	(80)
Non-operating items, net of tax	65	1,098	(963)	1,163	(985)
Adjusted net earnings from operations	\$ 4,568	\$ 2,446	\$ 1,496	\$ 7,014	\$ 3,932

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU Plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets, and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for the three months ended June 30, 2026 was a recovery of \$196 million (three months ended March 31, 2026 – \$644 million expense; three months ended June 30, 2025 – \$8 million expense; six months ended June 30, 2026 – \$448 million expense; six months ended June 30, 2025 – \$34 million expense).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. The pre-tax unrealized risk management gain for the three months ended June 30, 2026 was \$8 million (three months ended March 31, 2026 – \$316 million loss; three months ended June 30, 2025 – \$15 million gain; six months ended June 30, 2026 – \$308 million loss; six months ended June 30, 2025 – \$12 million gain).

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates and are recognized in net earnings. Pre- and after-tax amounts for these unrealized foreign exchange gains and losses are the same.

(4) Realized foreign exchange gains and losses associated with financing activities primarily result from the repayment of US dollar denominated debt and are recognized in net earnings. Pre- and after-tax amounts for these realized foreign exchange gains and losses are the same.

(5) During the second quarter of 2025, the Company acquired an interest in certain producing and non-producing assets in the North America Exploration and Production segment, resulting in a pre- and after-tax gain on acquisition of \$80 million representing the excess of the fair value of the net assets acquired compared to the total purchase consideration.

Adjusted Funds Flow

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated statements of cash flows adjusted for the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment, repay debt, and provide returns to shareholders through dividends and share buybacks. A reconciliation for adjusted funds flow from cash flows from operating activities is presented below.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Cash flows from operating activities	\$ 6,823	\$ 3,282	\$ 3,114	\$ 10,105	\$ 7,398
Net change in non-cash working capital	(120)	818	(24)	698	(106)
Abandonment expenditures	182	247	193	429	381
Movements in other long-term assets ⁽¹⁾	(19)	27	(21)	8	119
Adjusted funds flow	\$ 6,866	\$ 4,374	\$ 3,262	\$ 11,240	\$ 7,792

(1) Includes the unamortized cost of contributions to the Company's employee bonus program, interest on PRT recoveries in the North Sea, and prepaid cost of service tolls.

Adjusted Net Earnings from Operations and Adjusted Funds Flow, Per Common Share (Basic and Diluted)

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted) are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 14 to the financial statements. These non-GAAP measures, disclosed on a per share basis, enable a comparison to the per share amounts disclosed in the Company's financial statements prepared in accordance with IFRS Accounting Standards.

Netback

Netback is a non-GAAP ratio that represents net cash flows provided from core activities after the impact of all costs associated with bringing a product to market, on a per unit basis. The Company considers netback a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. Refer to the 'Operating Highlights – Exploration and Production' section of this MD&A for the netback calculations on a per unit basis for crude oil and NGLs and on a total barrels of oil equivalent basis.

The netback calculations include the realized price non-GAAP financial measure which is reconciled below to its respective line item in note 17 to the financial statements.

Realized Price (\$/bbl and \$/BOE) – Exploration and Production

Realized price (\$/bbl and \$/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 17 to the financial statements. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

Reconciliations for Exploration and Production realized crude oil and NGLs sales and BOE sales and the calculations for realized price are presented below.

(\$ millions, except bbl/d and \$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs (bbl/d)					
North America	611,384	606,104	551,248	608,759	556,685
International					
North Sea	7,372	4,332	6,778	5,860	11,197
Offshore Africa	2,000	—	500	1,006	5,745
Total International	9,372	4,332	7,278	6,866	16,942
Total sales volumes	620,756	610,436	558,526	615,625	573,627
Crude oil and NGLs sales ⁽¹⁾	\$ 7,535	\$ 5,425	\$ 4,655	\$ 12,960	\$ 10,279
Less: Blending and feedstock costs ⁽²⁾	1,598	1,248	1,119	2,846	2,510
Realized crude oil and NGLs sales	\$ 5,937	\$ 4,177	\$ 3,536	\$ 10,114	\$ 7,769
Realized price (\$/bbl)	\$ 105.11	\$ 76.02	\$ 69.58	\$ 90.77	\$ 74.82

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 to the financial statements.

(\$ millions, except BOE/d and \$/BOE)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Barrels of oil equivalent (BOE/d)					
North America	1,038,526	1,050,813	950,888	1,044,635	959,491
International					
North Sea	7,771	4,703	7,262	6,246	11,805
Offshore Africa	2,323	—	1,585	1,168	7,187
Total International	10,094	4,703	8,847	7,414	18,992
Total sales volumes	1,048,620	1,055,516	959,735	1,052,049	978,483
Barrels of oil equivalent sales ⁽¹⁾	\$ 8,013	\$ 6,223	\$ 5,221	\$ 14,236	\$ 11,535
Less: Blending and feedstock costs ⁽²⁾	1,598	1,248	1,119	2,846	2,510
Less: Sulphur income	(89)	(48)	(18)	(137)	(27)
Realized barrels of oil equivalent sales	\$ 6,504	\$ 5,023	\$ 4,120	\$ 11,527	\$ 9,052
Realized price (\$/BOE)	\$ 68.17	\$ 52.88	\$ 47.17	\$ 60.54	\$ 51.11

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 to the financial statements.

North America – Realized Product Prices and Royalties

Realized crude oil and NGLs price (\$/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 17 to the financial statements. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

Crude oil and NGLs royalty rate is a non-GAAP ratio that is calculated as crude oil and NGLs royalties divided by realized crude oil and NGLs sales. The Company considers crude oil and NGLs royalty rate a key measure in evaluating its performance, as it describes the Company's royalties for crude oil and NGLs sales volumes on a per unit basis.

A reconciliation for North America realized crude oil and NGLs sales and the calculations for realized crude oil and NGLs prices and the royalty rates are presented below.

(\$ millions, except \$/bbl and royalty rates)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Crude oil and NGLs sales ⁽¹⁾	\$ 7,427	\$ 5,389	\$ 4,595	\$ 12,816	\$ 9,961
Less: Blending and feedstock costs ⁽²⁾	1,598	1,248	1,119	2,846	2,510
Realized crude oil and NGLs sales	\$ 5,829	\$ 4,141	\$ 3,476	\$ 9,970	\$ 7,451
Realized crude oil and NGLs prices (\$/bbl)	\$ 104.77	\$ 75.91	\$ 69.30	\$ 90.48	\$ 73.95
Crude oil and NGLs royalties ⁽³⁾	\$ 1,116	\$ 737	\$ 467	\$ 1,853	\$ 1,223
Crude oil and NGLs royalty rates	19%	18%	13%	19%	16%

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 to the financial statements.

(3) Item is a component of royalties in note 17 to the financial statements.

Realized Product Prices – Oil Sands Mining and Upgrading

Realized SCO sales price (\$/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) divided by SCO sales volumes. Realized SCO sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 17 to the financial statements. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and the calculation for realized SCO sales price on a per unit basis are presented below.

(\$ millions, except for bbl/d and \$/bbl)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
SCO sales volumes (bbl/d)	623,486	594,042	463,586	608,845	532,434
Crude oil and NGLs sales ⁽¹⁾	\$ 8,143	\$ 5,537	\$ 4,023	\$ 13,680	\$ 9,902
Less: Blending and feedstock costs ⁽²⁾	1,005	743	345	1,748	1,048
Realized SCO sales	\$ 7,138	\$ 4,794	\$ 3,678	\$ 11,932	\$ 8,854
Realized SCO sales price (\$/bbl)	\$ 125.78	\$ 89.68	\$ 87.22	\$ 108.26	\$ 91.88

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs in note 17 to the financial statements.

Net Capital Expenditures

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated statements of cash flows, adjusted for the net change in non-cash working capital, and cash flows from investing activities not included in the Company's capital budget. The Company includes acquisition and disposition capital for property, plant and equipment and exploration and evaluation assets in net capital expenditures at close of the transactions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. A reconciliation of net capital expenditures is presented below.

(\$ millions)	Three Months Ended			Six Months Ended	
	Jun 30 2026	Mar 31 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Cash flows used in investing activities	\$ 2,468	\$ 1,949	\$ 1,941	\$ 4,417	\$ 3,253
Net change in non-cash working capital	(63)	79	(26)	16	(35)
Net capital expenditures	2,405	2,028	1,915	4,433	3,218
Abandonment expenditures	182	247	193	429	381
Capital and abandonment expenditures	\$ 2,587	\$ 2,275	\$ 2,108	\$ 4,862	\$ 3,599

Liquidity

Liquidity is a non-GAAP financial measure that represents the availability of readily available undrawn bank credit facilities, cash and cash equivalents, and other highly liquid assets to meet short-term funding requirements and to assist in assessing the Company's financial position. The Company's calculation of liquidity is presented below.

(\$ millions)	Jun 30 2026	Mar 31 2026	Dec 31 2025	Jun 30 2025
Undrawn bank credit facilities	\$ 5,356	\$ 5,358	\$ 5,668	\$ 4,723
Cash and cash equivalents	2,618	808	673	102
Liquidity	\$ 7,974	\$ 6,166	\$ 6,341	\$ 4,825

Long-term Debt, net

Long-term debt, net, is a capital management measure that represents long-term debt, including the current portion of long-term debt, less cash and cash equivalents, as disclosed in note 13 to the financial statements. A reconciliation of the Company's long-term debt, net is presented below.

(\$ millions)	Jun 30 2026	Mar 31 2026	Dec 31 2025	Jun 30 2025
Long-term debt	\$ 17,144	\$ 16,961	\$ 16,617	\$ 17,081
Less: Cash and cash equivalents	2,618	808	673	102
Long-term debt, net	\$ 14,526	\$ 16,153	\$ 15,944	\$ 16,979

Debt to Book Capitalization

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 13 to the financial statements.

After-Tax Return on Average Capital Employed

After-tax return on average capital employed as defined by the Company is a non-GAAP ratio. The ratio is calculated as net earnings plus after-tax interest and other financing expense for the twelve month trailing period as a percentage of average capital employed (defined as current and long-term debt plus shareholders' equity) for the twelve month trailing period. The Company considers this ratio a key measure in evaluating the Company's ability to generate profit and the efficiency with which it employs capital. A reconciliation of the Company's after-tax return on average capital employed is presented below.

(\$ millions, except ratios)	Jun 30 2026	Mar 31 2026	Dec 31 2025	Jun 30 2025
Interest adjusted after-tax return:				
Net earnings, 12 months trailing ⁽¹⁾	\$ 11,754	\$ 9,710	\$ 10,820	\$ 8,321
Interest and other financing expense, net of tax, 12 months trailing ⁽²⁾	686	686	640	608
Interest adjusted after-tax return	\$ 12,440	\$ 10,396	\$ 11,460	\$ 8,929
12 months average current portion long-term debt ⁽³⁾	\$ 1,059	\$ 902	\$ 1,293	\$ 1,528
12 months average long-term debt ⁽³⁾	15,955	16,169	16,149	13,174
12 months average common shareholders' equity ⁽³⁾	43,512	42,242	41,208	40,115
12 months average capital employed	\$ 60,526	\$ 59,313	\$ 58,650	\$ 54,817
After-tax return on average capital employed	20.6%	17.5%	19.5%	16.3%

(1) Net earnings, 12 months trailing includes a gain on acquisition, disposition, and remeasurement of \$4,989 million associated with the AOSP asset swap in the fourth quarter of 2025.

(2) The blended tax rate on interest was approximately 23% for each of the periods presented.

(3) For the purpose of this non-GAAP ratio, the measurement of average current and long-term debt and common shareholders' equity are determined on a consistent basis, as an average of the opening and quarterly period end values for the 12 month trailing period for each of the periods presented.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Jun 30 2026	Dec 31 2025
ASSETS			
Current assets			
Cash and cash equivalents		\$ 2,618	\$ 673
Accounts receivable		5,281	3,999
Inventory		2,790	2,621
Prepays and other		499	301
Current portion of other long-term assets	7	137	70
		11,325	7,664
Exploration and evaluation assets	4	2,777	2,651
Property, plant and equipment	5	78,745	77,645
Lease assets	6	2,927	3,001
Other long-term assets	7	809	869
		\$ 96,583	\$ 91,830
LIABILITIES			
Current liabilities			
Accounts payable		\$ 1,561	\$ 1,105
Accrued liabilities		4,794	4,255
Current income taxes payable		986	597
Current portion of long-term debt	8	2,214	441
Current portion of other long-term liabilities	9	1,762	1,665
		11,317	8,063
Long-term debt	8	14,930	16,176
Other long-term liabilities	9	12,167	11,936
Deferred income taxes		11,373	11,289
		49,787	47,464
SHAREHOLDERS' EQUITY			
Share capital	11	11,850	11,421
Retained earnings		34,684	32,726
Accumulated other comprehensive income	12	262	219
		46,796	44,366
		\$ 96,583	\$ 91,830

Commitments and contingencies (note 16)

Approved by the Board of Directors on August 5, 2026.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended		Six Months Ended	
		Jun 30 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Product sales	17	\$ 17,214	\$ 9,675	\$ 29,618	\$ 22,387
Less: royalties		(2,473)	(977)	(4,067)	(2,750)
Revenue		14,741	8,698	25,551	19,637
Expenses					
Production		2,508	2,159	4,896	4,531
Blending and feedstock		3,229	1,758	5,537	4,245
Transportation		690	707	1,360	1,360
Depletion, depreciation and amortization	5,6	1,902	1,765	3,779	3,635
Administration		159	151	313	303
Share-based compensation	9	(196)	8	448	34
Asset retirement obligation accretion	9	98	90	196	181
Interest and other financing expense		238	238	556	496
Risk management loss (gain)	15	44	(104)	405	(128)
Foreign exchange loss (gain)		181	(803)	443	(846)
Gain on acquisition		—	(80)	—	(80)
		8,853	5,889	17,933	13,731
Earnings before taxes		5,888	2,809	7,618	5,906
Current income tax expense	10	1,073	438	1,628	949
Deferred income tax expense (recovery)	10	312	(88)	139	40
Net earnings		\$ 4,503	\$ 2,459	\$ 5,851	\$ 4,917
Net earnings per common share					
Basic	14	\$ 2.17	\$ 1.17	\$ 2.81	\$ 2.34
Diluted	14	\$ 2.15	\$ 1.17	\$ 2.80	\$ 2.34

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended		Six Months Ended	
	Jun 30 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Net earnings	\$ 4,503	\$ 2,459	\$ 5,851	\$ 4,917
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of \$nil (2025 – \$nil) – three months ended; \$nil (2025 – \$nil) – six months ended	—	2	1	6
Reclassification to net earnings, net of taxes of \$nil (2025 – \$nil) – three months ended; \$nil (2025 – \$1 million) – six months ended	—	(2)	(2)	(7)
	—	—	(1)	(1)
Foreign currency translation adjustment				
Translation of net investment	22	(92)	44	(95)
Other comprehensive income (loss), net of taxes	22	(92)	43	(96)
Comprehensive income	\$ 4,525	\$ 2,367	\$ 5,894	\$ 4,821

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended	
		Jun 30 2026	Jun 30 2025
Share capital	11		
Balance – beginning of period		\$ 11,421	\$ 11,064
Issued upon exercise of stock options		318	151
Previously recognized liability on stock options exercised for common shares		242	175
Purchase of common shares under Normal Course Issuer Bid		(131)	(106)
Balance – end of period		11,850	11,284
Retained earnings			
Balance – beginning of period		32,726	28,103
Net earnings		5,851	4,917
Dividends on common shares	11	(2,598)	(2,461)
Purchase of common shares under Normal Course Issuer Bid, including tax	11	(1,295)	(750)
Balance – end of period		34,684	29,809
Accumulated other comprehensive income	12		
Balance – beginning of period		219	301
Other comprehensive income (loss), net of taxes		43	(96)
Balance – end of period		262	205
Shareholders' equity		\$ 46,796	\$ 41,298

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three Months Ended		Six Months Ended	
(millions of Canadian dollars, unaudited)	Note	Jun 30 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Operating activities					
Net earnings		\$ 4,503	\$ 2,459	\$ 5,851	\$ 4,917
Non-cash items					
Depletion, depreciation and amortization	5,6	1,902	1,765	3,779	3,635
Share-based compensation		(196)	8	448	34
Asset retirement obligation accretion		98	90	196	181
Unrealized risk management (gain) loss	15	(8)	(15)	308	(12)
Unrealized foreign exchange loss (gain)		157	(661)	442	(946)
Gain on acquisition		—	(80)	—	(80)
Deferred income tax expense (recovery)		312	(88)	139	40
Realized foreign exchange on financing activities ⁽¹⁾		98	(216)	77	23
Abandonment expenditures	9	(182)	(193)	(429)	(381)
Other		19	21	(8)	(119)
Net change in non-cash working capital		120	24	(698)	106
Cash flows from operating activities		6,823	3,114	10,105	7,398
Financing activities					
(Repayment) issuance of bank credit facilities and commercial paper, net	8	(67)	471	34	(20)
Repayment of other long-term debt	8	—	—	—	(876)
Payment of lease liabilities	6	(101)	(82)	(202)	(166)
Issuance of common shares on exercise of stock options	11	25	39	318	151
Dividends on common shares		(1,304)	(1,233)	(2,528)	(2,417)
Purchase of common shares under Normal Course Issuer Bid	11	(1,098)	(359)	(1,409)	(846)
Cash flows used in financing activities		(2,545)	(1,164)	(3,787)	(4,174)
Investing activities					
Net expenditures on exploration and evaluation assets	4,17	(25)	(51)	(111)	(57)
Net expenditures on property, plant and equipment	5,17	(2,380)	(1,864)	(4,472)	(3,161)
Proceeds from long-term contract		—	—	150	—
Net change in non-cash working capital		(63)	(26)	16	(35)
Cash flows used in investing activities		(2,468)	(1,941)	(4,417)	(3,253)
Increase (decrease) in cash and cash equivalents		1,810	9	1,901	(29)
Opening cash balance prior to restatement for IFRS 9	2	808	93	673	131
Adjustment on adoption of IFRS 9	2	—	—	44	—
Cash and cash equivalents – beginning of period		808	93	717	131
Cash and cash equivalents – end of period		\$ 2,618	\$ 102	\$ 2,618	\$ 102
Interest paid on long-term debt		\$ 222	\$ 237	\$ 423	\$ 494
Income taxes paid, net		\$ 629	\$ 229	\$ 1,292	\$ 914

(1) Realized foreign exchange on financing activities primarily relates to the repayment of US dollar denominated debt.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom portion of the North Sea; and Côte d'Ivoire in Offshore Africa.

The Oil Sands Mining and Upgrading segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's interest in the Athabasca Oil Sands Project ("AOSP").

Within Western Canada in the Midstream and Refining segment, the Company maintains certain activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("NWRP"), a general partnership formed to upgrade and refine bitumen in the Province of Alberta.

The Company was incorporated in Alberta, Canada. In June 2026, the Company relocated its head and registered office to 400 - 4th Avenue S.W., Calgary, AB, T2P 0J4.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34 "Interim Financial Reporting". The accounting policies applied are consistent with those used in the audited consolidated financial statements of the Company as at December 31, 2025, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2025.

Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions, and judgements regarding certain assets, liabilities, revenues, and expenses in the preparation of these interim consolidated financial statements, primarily related to unsettled transactions and events as of the date of these interim consolidated financial statements. Accordingly, actual results may differ from estimated amounts, and those differences may be material.

2. CHANGE IN ACCOUNTING POLICIES

In May 2024, the IASB issued amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures" to clarify the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled using an electronic payment system. The amendments also clarify the classification of certain financial assets, and add disclosure requirements for financial instruments with certain contingent features and for equity investments designated at fair value through other comprehensive income. The amendments were adopted January 1, 2026 retrospectively without restating comparative information in the interim consolidated statements of cash flows.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In April 2024, the IASB issued IFRS 18 "Presentation and Disclosure in Financial Statements", which provides presentation and disclosure requirements for the primary financial statements and related notes, replacing IAS 1 "Presentation of Financial Statements". IFRS 18 introduces defined categories for income and expenses and requires disclosure of new defined subtotals, including operating profit. The new standard also requires additional notes for management-defined performance measures ("MPM") and disclosure of certain expenses by nature. There are some associated changes to the statement of cash flows, including the starting point for the calculation of cash flows from operating activities and the categorization of interest and dividends. IFRS 18 is effective January 1, 2027, with early adoption permitted. The new standard is required to be adopted retrospectively.

The Company is currently evaluating the impact of adopting IFRS 18 on its consolidated financial statements and note disclosures. This assessment includes changes to the presentation of the consolidated statement of earnings, aggregation and disaggregation requirements, and a review of publicly disclosed measures to identify MPMs. In addition, the Company is adapting its processes, where appropriate, to capture data required by IFRS 18 for inclusion in the consolidated financial statements and note disclosures.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2025	\$ 2,594	\$ —	\$ —	\$ 57	\$ 2,651
Additions/Acquisitions, net	131	—	—	—	131
Transfers to property, plant and equipment	(5)	—	—	—	(5)
At June 30, 2026	\$ 2,720	\$ —	\$ —	\$ 57	\$ 2,777

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2025	\$ 92,896	\$ 9,270	\$ 5,316	\$ 60,570	\$ 503	\$ 699	\$ 169,254
Additions/Acquisitions, net	3,475	5	287	832	3	23	4,625
Transfers from exploration and evaluation assets	5	—	—	—	—	—	5
Derecognitions ⁽¹⁾	(211)	(477)	—	(43)	—	—	(731)
Foreign exchange adjustments and other	—	340	200	—	—	—	540
At June 30, 2026	\$ 96,165	\$ 9,138	\$ 5,803	\$ 61,359	\$ 506	\$ 722	\$ 173,693
Accumulated depletion and depreciation							
At December 31, 2025	\$ 65,940	\$ 9,270	\$ 4,035	\$ 11,617	\$ 246	\$ 501	\$ 91,609
Expense	2,196	5	15	1,331	8	19	3,574
Derecognitions ⁽¹⁾	(211)	(477)	—	(43)	—	—	(731)
Foreign exchange adjustments and other	(4)	340	156	4	—	—	496
At June 30, 2026	\$ 67,921	\$ 9,138	\$ 4,206	\$ 12,909	\$ 254	\$ 520	\$ 94,948
Net book value							
At June 30, 2026	\$ 28,244	\$ —	\$ 1,597	\$ 48,450	\$ 252	\$ 202	\$ 78,745
At December 31, 2025	\$ 26,956	\$ —	\$ 1,281	\$ 48,953	\$ 257	\$ 198	\$ 77,645

(1) An asset is derecognized when no future economic benefits are expected to arise from its continued use.

During the six months ended June 30, 2026, the Company acquired a number of producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment. These transactions were accounted for using the business combination method of accounting and are summarized below.

Peace River Crude Oil and NGLs, and Natural Gas Acquisitions

In June 2026, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets for net cash consideration of \$756 million, subject to final closing adjustments. Net assets acquired included exploration and evaluation assets of \$33 million, and property, plant and equipment of \$759 million. The Company also assumed asset retirement obligations of \$31 million, and assumed net working capital of \$5 million. No net deferred tax liabilities were recognized on this transaction.

During the first quarter of 2026, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets for net cash consideration of \$761 million, subject to final closing adjustments. Net assets acquired included exploration and evaluation assets of \$65 million, and property, plant and equipment of \$796 million. The Company also assumed asset retirement obligations of \$100 million. No net deferred tax liabilities were recognized on this transaction.

Pro Forma Information

As a result of the acquisition of assets in the Peace River area completed in the second quarter of 2026, revenue increased by approximately \$26 million and net operating income (comprised of revenue, less production and transportation expense) increased by approximately \$19 million for the second quarter of 2026. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately \$13 million for the second quarter of 2026.

As a result of the acquisition of assets in the Peace River area completed in the first quarter of 2026, revenue increased by approximately \$218 million and net operating income (comprised of revenue, less production and transportation expense) increased by approximately \$134 million for the period subsequent to the acquisition. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately \$95 million for the period subsequent to the acquisition.

If the acquisitions of assets in the Peace River area had been completed on January 1, 2026, the Company estimates that pro forma revenue would have increased by approximately \$437 million and pro forma net operating income (comprised of revenue, less production and transportation expense) would have increased by approximately \$290 million for the six months ended June 30, 2026. Including the impact of depletion, depreciation and amortization, the Company estimates earnings before taxes would have increased by approximately \$209 million for the six months ended June 30, 2026. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have been achieved had the acquisitions actually occurred on January 1, 2026, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition dates.

6. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2025	\$ 2,199	\$ 634	\$ 43	\$ 125	\$ 3,001
Additions	10	50	64	9	133
Depreciation	(80)	(97)	(16)	(12)	(205)
Foreign exchange adjustments and other	3	(3)	1	(3)	(2)
At June 30, 2026	\$ 2,132	\$ 584	\$ 92	\$ 119	\$ 2,927

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at June 30, 2026 were as follows:

	Jun 30 2026	Dec 31 2025
Lease liabilities	\$ 3,039	\$ 3,106
Less: current portion	357	373
	\$ 2,682	\$ 2,733

Total cash outflows for leases for the three months ended June 30, 2026, including payments related to short-term leases not reported as lease assets, were \$424 million (three months ended June 30, 2025 – \$378 million; six months ended June 30, 2026 – \$816 million; six months ended June 30, 2025 – \$732 million). Interest expense on leases for the three months ended June 30, 2026 was \$34 million (three months ended June 30, 2025 – \$15 million; six months ended June 30, 2026 – \$68 million; six months ended June 30, 2025 – \$31 million).

7. OTHER LONG-TERM ASSETS

	Jun 30 2026	Dec 31 2025
Long-term prepayments, contracts and other ⁽¹⁾	\$ 444	\$ 419
Prepaid cost of service tolls	208	229
Long-term inventory	294	291
	946	939
Less: current portion	137	70
	\$ 809	\$ 869

(1) Includes physical product sales contracts, interest on Petroleum Revenue Tax ("PRT") recoveries in the North Sea, and the unamortized cost of contributions to the Company's employee bonus program.

The Company has a 50% equity investment in NWRP. NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 barrels per day. The refinery's processing design capacity is approximately 50,000 barrels per day of bitumen feedstock, including 12,500 barrels per day of bitumen feedstock for the Company (25% toll payer) and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. Bitumen feedstock throughput can exceed design capacity when asset reliability and operational performance support higher processing rates. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058 (note 16). Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

The carrying value of the Company's interest in NWRP is \$nil, and as at June 30, 2026, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$405 million (December 31, 2025 – \$496 million). For the three months ended June 30, 2026, the Company's recovery of its share of unrecognized equity losses was \$66 million (six months ended June 30, 2026 – recovery of unrecognized equity losses of \$91 million; three months ended June 30, 2025 – recovery of unrecognized equity losses of \$24 million; six months ended June 30, 2025 – recovery of unrecognized equity losses of \$5 million).

8. LONG-TERM DEBT

	Jun 30 2026	Dec 31 2025
Canadian dollar denominated debt, unsecured		
Medium-term notes	\$ 3,116	\$ 3,116
US dollar denominated debt, unsecured		
Bank credit facilities (June 30, 2026 – US\$2,882 million; December 31, 2025 – US\$2,860 million)	4,094	3,922
US dollar debt securities (June 30, 2026 – US\$7,050 million; December 31, 2025 – US\$7,050 million)	10,014	9,669
	17,224	16,707
Less: original issue discounts, net ⁽¹⁾	13	14
transaction costs ^{(1) (2)}	67	76
	17,144	16,617
Less: current portion of long-term debt ^{(1) (2)}	2,214	441
	\$ 14,930	\$ 16,176

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.

(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency, and other professional fees.

Bank Credit Facilities and Commercial Paper

As at June 30, 2026, the Company had undrawn bank credit facilities of \$5,356 million, and a fully drawn non-revolving term credit facility of \$4,000 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit.

- a \$100 million demand credit facility;
- a \$500 million revolving credit facility, maturing June 2027;
- a \$4,000 million non-revolving term credit facility, maturing December 2027;
- a \$2,425 million revolving syndicated credit facility, maturing June 2028; and
- a \$2,425 million revolving syndicated credit facility, maturing June 2029.

During the first quarter of 2026, the Company cancelled the \$140 million portion of its \$2,565 million revolving syndicated credit facility, maturing June 2027, reducing the capacity to \$2,425 million, with a maturity of June 2029.

Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.

The Company's borrowings under its US commercial paper program are authorized up to a maximum of US\$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities outstanding as at June 30, 2026 was 4.9% (June 30, 2025 – 5.2%), and on total long-term debt outstanding for the six months ended June 30, 2026 was 4.9% (six months ended June 30, 2025 – 5.0%).

As at June 30, 2026, letters of credit and other financial security aggregating to \$965 million were outstanding (December 31, 2025 – \$840 million).

Medium-Term Notes

In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at June 30, 2026, the Company had \$1,350 million remaining on its base shelf prospectus.

US Dollar Debt Securities

In August 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US\$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance. As at June 30, 2026, the Company had US\$3,003 million remaining on its base shelf prospectus.

9. OTHER LONG-TERM LIABILITIES

	Jun 30 2026	Dec 31 2025
Asset retirement obligations	\$ 9,763	\$ 9,743
Lease liabilities (note 6)	3,039	3,106
Share-based compensation	494	433
Risk management (note 15)	373	65
Transportation and processing contracts	176	186
Other	84	68
	13,929	13,601
Less: current portion	1,762	1,665
	\$ 12,167	\$ 11,936

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.9% (December 31, 2025 – 4.9%) and inflation rates of up to 2% (December 31, 2025 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Jun 30 2026	Dec 31 2025
Balance – beginning of period	\$ 9,743	\$ 8,607
Liabilities incurred	21	34
Liabilities acquired, net	132	489
Liabilities settled	(429)	(771)
Asset retirement obligation accretion	196	380
Revision of cost, inflation, and timing estimates ⁽¹⁾	—	1,233
Change in discount rates	—	(129)
Foreign exchange adjustments	100	(100)
Balance – end of period	9,763	9,743
Less: current portion	1,049	956
	\$ 8,714	\$ 8,787

(1) Includes normal course revisions of cost, inflation, and timing estimates, as well as revisions to decommissioning timing and cost estimates in the North Sea and in Offshore Africa in 2025.

Share-Based Compensation

The liability for share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") Plan. The Company's Stock Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The PSU Plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined with reference to the value of the Company's shares, by individual employee performance, and the extent to which certain other performance measures are met.

The Company recognizes a liability for potential cash settlements under these plans. The current portion of the liability represents the maximum amount of the liability payable within the next twelve month period if all vested stock options and PSUs are settled in cash.

	Jun 30 2026	Dec 31 2025
Balance – beginning of period	\$ 433	\$ 620
Share-based compensation expense	448	180
Cash payment for stock options surrendered and PSUs vested	(149)	(94)
Transferred to common shares	(242)	(273)
Other	4	—
Balance – end of period	494	433
Less: current portion	329	312
	\$ 165	\$ 121

10. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	Three Months Ended		Six Months Ended	
	Jun 30 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Current corporate income tax – North America ⁽¹⁾	\$ 1,164	\$ 529	\$ 1,835	\$ 1,098
Current corporate income tax – North Sea	(46)	(45)	(99)	(71)
Current corporate income tax – Offshore Africa	1	—	1	5
Current PRT ⁽²⁾ – North Sea	(49)	(49)	(114)	(88)
Other taxes	3	3	5	5
Current income tax	1,073	438	1,628	949
Deferred corporate income tax	275	(106)	216	13
Deferred PRT ⁽²⁾ – North Sea	37	18	(77)	27
Deferred income tax	312	(88)	139	40
Income tax	\$ 1,385	\$ 350	\$ 1,767	\$ 989

(1) Includes North America Exploration and Production, Oil Sands Mining and Upgrading, and Midstream and Refining segments.

(2) Petroleum Revenue Tax.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares	Six Months Ended Jun 30, 2026	
	Number of shares (thousands)	Amount
Balance – beginning of period	2,081,578	\$ 11,421
Issued upon exercise of stock options	10,187	318
Previously recognized liability on stock options exercised for common shares	—	242
Purchase of common shares under Normal Course Issuer Bid	(22,925)	(131)
Balance – end of period	2,068,840	\$ 11,850

Dividends

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 4, 2026, the Board of Directors approved a 6% increase in the quarterly dividend to \$0.625 per common share, beginning with the dividend paid on April 7, 2026.

On March 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to \$0.5875 per common share.

Normal Course Issuer Bid

On March 10, 2026, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 182,396,564 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2026 and ending March 12, 2027, subject to applicable securities laws.

For the six months ended June 30, 2026, the Company purchased 22,925,000 common shares at a weighted average price of \$61.47 per common share for a total cost, including tax, of \$1,426 million. Retained earnings were reduced by \$1,295 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2026, up to and including August 4, 2026, the Company purchased 7,500,000 common shares at a weighted average price of \$61.44 per common share for a total cost, including tax, of \$470 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at June 30, 2026:

	Six Months Ended Jun 30, 2026	
	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	54,734	\$ 39.83
Granted	17,201	55.41
Exercised for common shares	(10,187)	31.18
Surrendered for cash settlement	(4,118)	39.21
Forfeited	(1,368)	43.46
Outstanding – end of period	56,262	\$ 46.11
Exercisable – end of period	7,024	\$ 40.10

The Stock Option Plan is a "rolling 7%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 7% of the common shares outstanding from time to time.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

	Jun 30 2026	Jun 30 2025
Derivative financial instruments designated as cash flow hedges	\$ 65	\$ 69
Foreign currency translation adjustment	197	136
	\$ 262	\$ 205

13. CAPITAL DISCLOSURES

The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the ratio of current and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current and long-term debt less cash and cash equivalents. As at June 30, 2026, the ratio was 23.7%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS Accounting Standards and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Jun 30 2026	Dec 31 2025
Long-term debt	\$ 17,144	\$ 16,617
Less: cash and cash equivalents	2,618	673
Long-term debt, net	\$ 14,526	\$ 15,944
Total shareholders' equity	\$ 46,796	\$ 44,366
Debt to book capitalization	23.7%	26.4%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at June 30, 2026, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Weighted average common shares outstanding – basic (thousands of shares)	2,077,894	2,093,135	2,081,188	2,096,817
Effect of dilutive stock options (thousands of shares)	11,942	6,530	11,531	7,508
Weighted average common shares outstanding – diluted (thousands of shares)	2,089,836	2,099,665	2,092,719	2,104,325
Net earnings	\$ 4,503	\$ 2,459	\$ 5,851	\$ 4,917
Net earnings per common share – basic	\$ 2.17	\$ 1.17	\$ 2.81	\$ 2.34
– diluted	\$ 2.15	\$ 1.17	\$ 2.80	\$ 2.34

15. FINANCIAL INSTRUMENTS

The Company's financial instruments are comprised of cash and cash equivalents, accounts receivable, risk management assets and liabilities, accounts payable, accrued liabilities, lease liabilities, and long-term debt. These financial instruments, with the exception of risk management assets and liabilities, are classified as financial assets and liabilities at amortized cost. Risk management assets and liabilities are classified as derivatives held for trading, cash flow hedges, or embedded derivatives.

The estimated fair values of derivative financial instruments in Level 2 and Level 3 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications, including quoted forward prices for commodities, foreign exchange rates, interest yield curves, and other volatility factors.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)	Jun 30 2026	Dec 31 2025
Balance – beginning of period	\$ (65)	\$ 5
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities ^{(1) (2) (3) (4)}	(308)	(68)
Foreign exchange	—	(1)
Other comprehensive income	—	(1)
Balance – end of period	(373)	(65)
Less: current portion	(6)	(8)
	\$ (367)	\$ (57)

(1) Risk management liabilities are disclosed in note 9.

(2) In the third quarter of 2025, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US\$1.30 AECO for the period of August to December 2025, and 25,000 MMBtu/d of natural gas at US\$2.16 AECO for the period of January to December 2026.

(3) In the second quarter of 2025, the Company entered into a long-term natural gas supply agreement that contains an embedded derivative.

(4) In the fourth quarter of 2024, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US\$1.47 AECO, and 25,000 MMBtu/d of natural gas at US\$1.82 AECO for the period of January to December 2025.

Net loss (gain) from risk management activities was as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2026	Jun 30 2025	Jun 30 2026	Jun 30 2025
Net realized risk management loss (gain)	\$ 52	\$ (89)	\$ 97	\$ (116)
Net unrealized risk management (gain) loss	(8)	(15)	308	(12)
	\$ 44	\$ (104)	\$ 405	\$ (128)

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The Company's financial instruments are categorized as Level 1 with the exception of risk management assets and liabilities, which are categorized as Level 2, and embedded derivatives, which are categorized as Level 3. There were no transfers between Level 1, 2, and 3 financial instruments. The fair values of the Company's fixed rate long-term debt is outlined below:

	Jun 30, 2026	
	Carrying amount	Level 1 Fair Value
Fixed rate long-term debt ^{(1) (2)}	\$ 13,050	\$ 13,252

(1) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

(2) Includes the current portion of fixed rate long-term debt.

Embedded Derivative

During the second quarter of 2025, the Company entered into a long-term natural gas supply agreement to supply 140,000 MMBtu/d of natural gas for a term of 15 years, with delivery anticipated to begin in 2030 as all conditions precedent have been waived by the counterparty. Under the terms of the agreement, the Company will deliver natural gas to its counterparty in Illinois, USA and receive a Japan Korea Marker ("JKM") index price less deductions for transportation and liquefaction. The contract includes an embedded derivative as a result of the pricing structure, and the host contract is the natural gas sales agreement with a Chicago Citygate price.

The natural gas embedded derivative is categorized as Level 3 within the fair value hierarchy, as the fair value is determined using a discounted estimated cash flow model which incorporates significant unobservable inputs, including future natural gas pricing and a discount rate.

The Company recognizes a loss (gain) on risk management activities in the statements of earnings related to its natural gas embedded derivative. The loss (gain) is determined by the relative movements in fair value compared to the prior period. For the three months ended June 30, 2026, the Company recognized an unrealized risk management gain of \$2 million on the natural gas embedded derivative (six months ended June 30, 2026 – unrealized loss of \$310 million; three months ended June 30, 2025 – unrealized gain of \$11 million; six months ended June 30, 2025 – unrealized gain of \$11 million). As at June 30, 2026, the fair value of the embedded derivative was a liability of \$367 million (December 31, 2025 – \$57 million liability).

The Level 3 fair value measurements of the embedded derivative could be materially impacted by a change in the discount rate and movements in natural gas prices. The following table summarizes the impacts to the fair value of the embedded derivative resulting from changes in the specified variable over the 15-year contract. These sensitivities as at June 30, 2026 are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities.

	JKM price		Discount rate	
	US\$0.10/MMBtu increase	US\$0.10/MMBtu decrease	1% increase	1% decrease
Fair value – increase/(decrease)	\$ 55	\$ (55)	\$ (57)	\$ 67

Financial Risk Factors

The Company's financial risks are consistent with those discussed in notes 1, 3 and 18 of the Company's audited consolidated financial statements for the year ended December 31, 2025.

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange rate risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production, and with natural gas purchases. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. As at June 30, 2026, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper, and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into foreign currency forward contracts, SOFR loans, and commercial paper to mitigate its foreign currency exchange rate risk.

As at June 30, 2026, the Company had US\$1,500 million of foreign currency forward contracts outstanding (December 31, 2025 – US\$1,500 million), with original terms of up to 90 days, all of which were designated as derivatives held for trading (December 31, 2025 – US\$1,500 million).

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at June 30, 2026, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper, and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

As at June 30, 2026, the maturity dates of the Company's financial liabilities were as follows:

		Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	\$	1,561	\$ —	\$ —	\$ —
Accrued liabilities	\$	4,794	\$ —	\$ —	\$ —
Long-term debt ⁽¹⁾	\$	2,214	\$ 4,320	\$ 2,876	\$ 7,814
Other long-term liabilities ^{(2) (3)}	\$	363	\$ 292	\$ 635	\$ 2,230
Interest and other financing expense ⁽⁴⁾	\$	979	\$ 790	\$ 1,842	\$ 3,501

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, \$357 million; one to less than two years, \$292 million; two to less than five years, \$635 million; and thereafter, \$1,755 million.

(3) Includes a gross derivative liability of \$475 million associated with the Company's natural gas embedded derivative. The gross liability is offset by a gross derivative asset of \$108 million, resulting in a net liability of \$367 million.

(4) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at June 30, 2026.

16. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at June 30, 2026:

	Remaining 2026	2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing ^{(1) (2)}	\$ 1,179	\$ 2,317	\$ 2,171	\$ 2,010	\$ 1,849	\$ 18,309
North West Redwater Partnership service toll ⁽³⁾	\$ 48	\$ 96	\$ 97	\$ 95	\$ 95	\$ 3,885
Offshore vessels and decommissioning equipment	\$ 207	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and supplies	\$ 94	\$ 122	\$ 121	\$ 24	\$ 24	\$ 170
Office leases and other	\$ 144	\$ 66	\$ 19	\$ 18	\$ 18	\$ 176

(1) The Company's commitment for its 20-year product transportation agreement ending in 2044 on the Trans Mountain Expansion pipeline reflects interim tolls approved by the Canada Energy Regulator in the fourth quarter of 2023, and is subject to change pending the approval of final tolls.

(2) During the second quarter of 2026, the Company executed crude oil transportation agreements delivering between 150,000 bbl/d and 165,000 bbl/d of new pipeline capacity to U.S. markets, with service currently expected to commence in the fourth quarter of 2028. These agreements are subject to certain conditions precedent, including a final investment decision by the project proponents and certain regulatory approvals. Accordingly, the related agreements will not be recognized as commitments until the completion of all conditions precedent. The transportation agreements have a term of 20 years and, if all conditions are met, will result in transportation payments of approximately \$500 million to \$550 million annually being added to the Company's commitments.

(3) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is \$1,751 million of interest payable over the 40-year tolling period, ending in 2058 (note 7).

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement, and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

17. SEGMENTED INFORMATION

	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended	
	Jun 30		Jun 30		Jun 30		Jun 30		Jun 30		Jun 30		Jun 30		Jun 30	
(millions of Canadian dollars, unaudited)	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025
Segmented product sales																
Crude oil and NGLs ⁽¹⁾	\$ 7,427	\$ 4,595	\$ 12,816	\$ 9,961	\$ 82	\$ 56	\$ 118	\$ 208	\$ 26	\$ 4	\$ 26	\$ 110	\$ 7,535	\$ 4,655	\$ 12,960	\$ 10,279
Natural gas ⁽¹⁾	473	555	1,269	1,226	3	3	5	9	2	8	2	21	478	566	1,276	1,256
Other income and revenue	106	16	153	33	—	—	—	—	—	—	—	1	106	16	153	34
Total segmented product sales	8,006	5,166	14,238	11,220	85	59	123	217	28	12	28	132	8,119	5,237	14,389	11,569
Less: royalties	(1,146)	(487)	(1,927)	(1,268)	—	—	—	—	(1)	(1)	(1)	(6)	(1,147)	(488)	(1,928)	(1,274)
Segmented revenue	6,860	4,679	12,311	9,952	85	59	123	217	27	11	27	126	6,972	4,749	12,461	10,295
Segmented expenses																
Production	1,018	829	2,024	1,723	96	118	131	288	31	8	31	43	1,145	955	2,186	2,054
Blending and feedstock	1,598	1,119	2,846	2,510	—	—	—	—	—	—	—	—	1,598	1,119	2,846	2,510
Transportation	539	518	1,063	994	5	1	7	4	—	—	—	—	544	519	1,070	998
Depletion, depreciation and amortization	1,135	1,085	2,266	2,177	6	33	12	73	12	13	26	72	1,153	1,131	2,304	2,322
Asset retirement obligation accretion	54	53	109	106	21	14	41	28	1	2	3	4	76	69	153	138
Risk management (gain) loss (commodity derivatives)	(1)	1	316	(11)	—	—	—	—	—	—	—	—	(1)	1	316	(11)
Gain on acquisition	—	(80)	—	(80)	—	—	—	—	—	—	—	—	—	(80)	—	(80)
Total segmented expenses	4,343	3,525	8,624	7,419	128	166	191	393	44	23	60	119	4,515	3,714	8,875	7,931
Segmented earnings (loss)	\$ 2,517	\$ 1,154	\$ 3,687	\$ 2,533	\$ (43)	\$ (107)	\$ (68)	\$ (176)	\$ (17)	\$ (12)	\$ (33)	\$ 7	\$ 2,457	\$ 1,035	\$ 3,586	\$ 2,364
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management loss (gain) (other)																
Foreign exchange loss (gain)																
Total non-segmented expenses (earnings)																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

	Oil Sands Mining and Upgrading				Midstream and Refining				Inter-segment Elimination and Other				Total			
	Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended	
	Jun 30		Jun 30		Jun 30		Jun 30		Jun 30		Jun 30		Jun 30		Jun 30	
(millions of Canadian dollars, unaudited)	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025	2026	2025
Segmented product sales																
Crude oil and NGLs ^{(1) (2)}	\$ 8,143	\$ 4,023	\$ 13,680	\$ 9,902	\$ 23	\$ 22	\$ 46	\$ 44	\$ 366	\$ 174	\$ 495	\$ 381	\$ 16,067	\$ 8,874	\$ 27,181	\$ 20,606
Natural gas ⁽¹⁾	—	—	—	—	—	—	—	—	25	34	59	60	503	600	1,335	1,316
Other income and revenue	191	48	325	73	346	137	623	358	1	—	1	—	644	201	1,102	465
Total segmented product sales	8,334	4,071	14,005	9,975	369	159	669	402	392	208	555	441	17,214	9,675	29,618	22,387
Less: royalties	(1,326)	(489)	(2,139)	(1,476)	—	—	—	—	—	—	—	—	(2,473)	(977)	(4,067)	(2,750)
Segmented revenue	7,008	3,582	11,866	8,499	369	159	669	402	392	208	555	441	14,741	8,698	25,551	19,637
Segmented expenses																
Production	1,259	1,120	2,528	2,305	93	66	156	139	11	18	26	33	2,508	2,159	4,896	4,531
Blending and feedstock ⁽²⁾	1,005	345	1,748	1,048	241	105	411	277	385	189	532	410	3,229	1,758	5,537	4,245
Transportation	146	157	285	331	4	31	8	35	(4)	—	(3)	(4)	690	707	1,360	1,360
Depletion, depreciation and amortization	744	630	1,466	1,305	5	4	9	8	—	—	—	—	1,902	1,765	3,779	3,635
Asset retirement obligation accretion	22	21	43	43	—	—	—	—	—	—	—	—	98	90	196	181
Risk management (gain) loss (commodity derivatives)	—	—	—	—	—	—	—	—	—	—	—	—	(1)	1	316	(11)
Gain on acquisition	—	—	—	—	—	—	—	—	—	—	—	—	—	(80)	—	(80)
Total segmented expenses	3,176	2,273	6,070	5,032	343	206	584	459	392	207	555	439	8,426	6,400	16,084	13,861
Segmented earnings (loss)	\$ 3,832	\$ 1,309	\$ 5,796	\$ 3,467	\$ 26	\$ (47)	\$ 85	\$ (57)	\$ —	\$ 1	\$ —	\$ 2	\$ 6,315	\$ 2,298	\$ 9,467	\$ 5,776
Non-segmented expenses																
Administration													159	151	313	303
Share-based compensation													(196)	8	448	34
Interest and other financing expense													238	238	556	496
Risk management loss (gain) (other)													45	(105)	89	(117)
Foreign exchange loss (gain)													181	(803)	443	(846)
Total non-segmented expenses (earnings)													427	(511)	1,849	(130)
Earnings before taxes													5,888	2,809	7,618	5,906
Current income tax													1,073	438	1,628	949
Deferred income tax													312	(88)	139	40
Net earnings													\$ 4,503	\$ 2,459	\$ 5,851	\$ 4,917

(1) Product sales in the North America Exploration and Production and Oil Sands Mining and Upgrading segments originate in Canada.

(2) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.

Capital Expenditures ⁽¹⁾

Six Months Ended						
	Jun 30, 2026			Jun 30, 2025		
	Net expenditures	Non-cash and fair value changes ⁽²⁾	Capitalized costs	Net expenditures	Non-cash and fair value changes ⁽²⁾	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	\$ 111	\$ 15	\$ 126	\$ 57	\$ 78	\$ 135
	111	15	126	57	78	135
Property, plant and equipment						
Exploration and Production						
North America	3,322	(53)	3,269	1,889	(10)	1,879
North Sea	5	(477)	(472)	11	—	11
Offshore Africa	287	—	287	219	—	219
	3,614	(530)	3,084	2,119	(10)	2,109
Oil Sands Mining and Upgrading	832	(43)	789	997	(304)	693
Midstream and Refining	3	—	3	4	—	4
Head Office	23	—	23	41	—	41
	4,472	(573)	3,899	3,161	(314)	2,847
	\$ 4,583	\$ (558)	\$ 4,025	\$ 3,218	\$ (236)	\$ 2,982

(1) This table provides a reconciliation of capitalized costs, reported in note 4 and note 5, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

(2) Derecognitions, asset retirement obligations, transfer of exploration and evaluation assets, and other fair value adjustments.

Segmented Assets

	Jun 30 2026	Dec 31 2025
Exploration and Production		
North America	\$ 37,456	\$ 33,462
North Sea	810	789
Offshore Africa	1,755	1,398
Other	37	35
Oil Sands Mining and Upgrading	54,892	54,699
Midstream and Refining	1,326	1,142
Head Office	307	305
	\$ 96,583	\$ 91,830

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated August 2025. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended June 30, 2026:

Interest coverage (times)	
Net earnings ⁽¹⁾	17.7x
Adjusted funds flow ⁽²⁾	25.0x

(1) Net earnings plus income taxes and interest expense; divided by interest expense.

(2) Adjusted funds flow (as defined in the Company's Management's Discussion and Analysis), plus current income taxes and interest expense; divided by interest expense.

This Page Left Intentionally Blank

CORPORATE INFORMATION

Board of Directors

Shelley A. M. Brown, C.M., F.C.P.A, F.C.A, ICD.D
Dr. M. Elizabeth Cannon, O.C.
N. Murray Edwards, C.M.
Christopher L. Fong
Ambassador Gordon D. Giffin
Christine M. Healy
Dr. Grant E. Isaac
Steve W. Laut
Honourable Frank J. McKenna, P.C., O.C., O.N.B., K.C.
Scott G. Stauth
David A. Tuer
Annette M. Verschuren, O.C.

Officers

N. Murray Edwards
Executive Chairman
Scott G. Stauth
President
Robin S. Zabek
Chief Operating Officer, Exploration and Production
Jay E. Froc
Chief Operating Officer, Oil Sands
Ron K. Laing
Chief Commercial and Corporate Development Officer
Victor C. Darel
Chief Financial Officer
Troy J.P. Andersen
Senior Vice-President, Canadian Conventional Field Operations
Calvin J. Bast
Senior Vice-President, Production
Dwayne F. Giggs
Senior Vice-President, Exploration
Dean W. Halewich
Senior Vice-President, Safety, Risk Management and Innovation
Sheryl L. Kapeluck
Senior Vice-President, Finance
Devin C. Lowe
Senior Vice-President, Exploitation
Warren P. Raczynski
Senior Vice-President, Thermal
Kara L. Slemko
Senior Vice-President, Commercial Operations and Corporate Development
Trevor T. Wagil
Senior Vice-President, Oil Sands Mining and Upgrading
Brenda G. Balog
Vice-President, Legal and General Counsel
Erin L. Lunn
Vice-President, Land
Mark A. Overwater
Vice-President, Marketing
Kyle G. Pisio
Vice-President, Drilling, Completions and Asset Retirement
Stephanie A. Graham
Corporate Secretary and Associate General Counsel, Canada

CNR International (U.K.) Limited Aberdeen, Scotland

Barry Duncan
Managing Director and
Vice-President, Finance, International

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ
New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario
Computershare Investor Services LLC
New York, New York

Investor Relations

Phone: (403) 514-7777
Email: ir@cnrl.com

CANADIAN NATURAL RESOURCES LIMITED

T (403) 517-6700 F (403) 517-7350 E ir@cnrl.com

400 4 Avenue S.W. Calgary, AB T2P 0J4

www.cnrl.com