THIRD QUARTER REPORT

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2024 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2024 THIRD QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's third quarter results, "Our unique and diverse asset base provides us with a competitive advantage, as we can allocate capital to the highest return projects without being reliant on any one commodity. Our consistent and top tier results are driven by safe and reliable operations. Our commitment to continuous improvement is supported by a strong team culture in all areas of our company that focus on improving our costs, driving execution of growth opportunities and increasing value to shareholders.

We achieved strong average production of approximately 1,363,000 BOE/d in Q3/24, consisting of 1,022,000 bbl/d of liquids and over 2.0 Bcf/d of natural gas. Our world class Oil Sand Mining and Upgrading assets delivered Q3/24 production of approximately 498,000 bbl/d of long life no decline Synthetic Crude Oil (”SCO”), including record monthly production of approximately 529,000 bbl/d of SCO in August 2024. These assets continue to drive strong operational performance and high utilization rates resulting in top tier quarterly operating costs of $20.67/bbl (US$15.16/bbl) driving significant free cash flow in Q3/24.

Subsequent to quarter end and subject to regulatory approvals, we announced that we have entered into an agreement to acquire Chevron Canada Limited's ("Chevron") 20% interest in the Athabasca Oil Sands Project (“AOSP”), which includes the Muskeg River and Jackpine mines, the Scotford Upgrader and the Quest Carbon Capture and Storage facility. This acquisition will bring Canadian Natural’s total working interest in AOSP to 90% and adds approximately 62,500 bbl/d of SCO production, contributing to Canadian Natural’s significant sustainable free cash flow generation. The Company also announced that we have entered into an agreement to acquire Chevron’s 70% operated working interest of light crude oil and liquids rich assets in the Duvernay play in Alberta. Production from these assets is targeted to average approximately 60,000 BOE/d in 2025, consisting of 179 MMcf/d of natural gas and 30,000 bbl/d of liquids. These Duvernay assets provide the opportunity for robust growth while contributing meaningful free cash flow. Both of these assets are a great fit for Canadian Natural and when combined with our strong operating culture will drive significant value for shareholders."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "In Q3/24, we delivered strong financial results, including adjusted net earnings of approximately $2.1 billion and adjusted funds flow of $3.9 billion, which drove significant returns to shareholders totaling $1.9 billion in the quarter. Year-to-date, up to and including October 30, 2024, we have distributed significant value to shareholders, totaling approximately $6.7 billion, inclusive of our sustainable and growing dividend and share repurchases.

Given our strong financial position and significant and sustainable free cash flow generation, as previously announced, the Board of Directors has agreed to increase the quarterly dividend by 7% to $0.5625 per share payable at the next regular quarterly dividend payment in January 2025. This will mark 2025 as the 25th consecutive year of dividend increases by Canadian Natural, with a compound annual growth rate (“CAGR”) of 21% over that time.

This increase in the quarterly dividend demonstrates the confidence that the Board of Directors has in the Company’s world class assets and its ability to generate significant and sustainable free cash flow. Our asset base is underpinned by top tier, long life low decline assets, a strong balance sheet and safe, effective and efficient operations all of which combine to provide us with unique competitive advantages in terms of capital efficiency, flexibility and sustainability, driving strong returns on capital."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2024	Three Months Ended Jun 30 2024	Three Months Ended Sep 30 2023	Nine Months Ended Sep 30 2024	Nine Months Ended Sep 30 2023
Net earnings	**$ 2,266**	$ 1,715	$ 2,344	**$ 4,968**	$ 5,606
Per common share [(1)] – basic	**$ 1.07**	$ 0.80	$ 1.08	**$ 2.33**	$ 2.56
– diluted	**$ 1.06**	$ 0.80	$ 1.06	**$ 2.31**	$ 2.53
Adjusted net earnings from operations [(2)]	**$ 2,071**	$ 1,892	$ 2,850	**$ 5,437**	$ 5,987
Per common share [(1)] – basic [(3)]	**$ 0.98**	$ 0.89	$ 1.31	**$ 2.55**	$ 2.73
– diluted [(3)]	**$ 0.97**	$ 0.88	$ 1.30	**$ 2.53**	$ 2.71
Cash flows from operating activities	**$ 3,002**	$ 4,084	$ 3,498	**$ 9,954**	$ 7,538
Adjusted funds flow [(2)]	**$ 3,921**	$ 3,614	$ 4,684	**$ 10,673**	$ 10,855
Per common share [(1)] – basic [(3)]	**$ 1.85**	$ 1.69	$ 2.15	**$ 5.01**	$ 4.96
– diluted [(3)]	**$ 1.84**	$ 1.68	$ 2.13	**$ 4.97**	$ 4.91
Cash flows used in investing activities	**$ 1,274**	$ 1,015	$ 1,199	**$ 3,681**	$ 3,912
Net capital expenditures [(4)]	**$ 1,349**	$ 1,621	$ 1,108	**$ 4,083**	$ 3,934
Abandonment expenditures	**$ 204**	$ 129	$ 123	**$ 495**	$ 360
Daily production, before royalties					
Natural gas (MMcf/d)	**2,049**	2,110	2,151	**2,102**	2,125
Crude oil and NGLs (bbl/d)	**1,021,572**	934,066	1,035,153	**977,265**	948,587
Equivalent production (BOE/d) [(5)]	**1,363,086**	1,285,798	1,393,614	**1,327,593**	1,302,715

(1) Per common share and dividend amounts have been updated to reflect the two for one common share split. Further details are disclosed in the Advisory section of the Company's MD&A and in the financial statements for the three and nine months ended September 30, 2024 dated October 30, 2024.

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2024 dated October 30, 2024.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2024 dated October 30, 2024.

(4) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2023 and has been updated for all periods presented. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2024 dated October 30, 2024.

(5) 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.

- The strength of Canadian Natural's long life low decline asset base, supported by safe, effective and efficient operations, makes our business unique, robust and sustainable. In Q3/24, the Company generated strong financial results, including:
  - Net earnings of approximately $2.3 billion and adjusted net earnings from operations of approximately $2.1 billion.
  - Cash flows from operating activities of approximately $3.0 billion.
  - Adjusted funds flow of approximately $3.9 billion.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with approximately $6.2 billion in liquidity[(1)] as at September 30, 2024.
- Canadian Natural delivered quarterly average production in Q3/24 of 1,363,086 BOE/d, a decrease of 2% from Q3/23 levels of 1,393,614 BOE/d. Production in Q3/24 consisted of total liquids production of 1,021,572 bbl/d and natural gas production of 2,049 MMcf/d.
  - The Company's world class Oil Sands Mining and Upgrading assets delivered strong production averaging 497,656 bbl/d of high value SCO in Q3/24, approximately 7,000 bbl/d higher than Q3/23 levels. These quarterly production volumes in Q3/24 included the impacts of planned turnaround activities at the non-operated Scotford Upgrader.

    - Oil Sands Mining and Upgrading achieved a new monthly production record of approximately 529,000 bbl/d of SCO in August 2024. This was primarily due to high utilization at both Horizon and AOSP as well as the completion of the reliability enhancement project at Horizon during the planned turnaround in Q2/24.
    - Oil Sands Mining and Upgrading operating costs continue to be top tier, averaging $20.67/bbl (US$15.16/bbl) in Q3/24, a decrease of 7% from Q3/23 levels, primarily reflecting higher production volumes and lower energy costs.
    - Due to stronger than budgeted production volumes at the Scotford Upgrader concurrent with reduced duration of the planned turnaround, the annual net production impact to AOSP from these planned turnaround activities was reduced to approximately 5,400 bbl/d, a significant improvement compared to the budgeted annual net production impact of 11,000 bbl/d. The planned turnaround commenced on September 9, 2024 and was successfully completed subsequent to quarter end on October 18, 2024.
    - Additionally, a debottlenecking project was completed during the planned turnaround at the Scotford Upgrader which increases gross AOSP capacity by approximately 8,000 bbl/d. Upon closing the acquisition of Chevron's 20% interest in AOSP, the capacity net to Canadian Natural increases by approximately 7,200 bbl/d.
  - Thermal in situ long life low decline production averaged 271,551 bbl/d in Q3/24, a decrease of 5% from Q3/23 levels, primarily due to the cyclical nature of production from Cyclic Steam Stimulation ("CSS") pads at Primrose and natural field declines, partially offset by Steam Assisted Gravity Drainage ("SAGD") pad additions at Kirby and Jackfish.
    - At Jackfish, the Company achieved record quarterly production of approximately 128,000 bbl/d in Q3/24, primarily due to strong results from pad additions and effective and efficient operations.
    - At Wolf Lake, the Company recently drilled a SAGD pad which is targeted to come on production in Q4/24 and as a result of strong execution targets to reach full production capacity in Q1/25, one quarter ahead of schedule.
- During 2024, the Company has increased its contracted crude oil transportation capacity to 256,500 bbl/d, expanding its committed volumes to Canada’s West Coast and to the United States Gulf Coast ("USGC") to approximately 25% of liquids production compared to the mid-point of 2024 corporate annual guidance. The additional egress supports Canadian Natural’s long-term sales strategy by targeting expanded refining markets, driving stronger netbacks while also reducing exposure to egress constraints.
  - Commencing December 1, 2024, the Company will increase its capacity on the Trans Mountain Expansion ("TMX") pipeline by 75,000 bbl/d to a total of 169,000 bbl/d.
  - As previously disclosed, the Company increased its capacity on the Flanagan South pipeline in Q1/24 by 55,000 bbl/d to a total of 77,500 bbl/d, further expanding the Company's heavy oil diversification and market access to the USGC.
  - The Company also has committed volumes of 10,000 bbl/d on the Keystone Base pipeline, with direct access to the USGC.
- Subsequent to quarter end, Canadian Natural announced that it entered into an agreement to acquire Chevron's 20% interest in AOSP, which includes the Muskeg River and Jackpine mines, the Scotford Upgrader and the Quest Carbon Capture and Storage facility. Concurrently, the Company also entered into an agreement to acquire Chevron's 70% operated working interest in light crude oil and liquids rich assets in the Duvernay play in Alberta. Both of these acquisitions are targeted to contribute significant additional free cash flow to the Company.
  - The AOSP acquisition brings Canadian Natural’s total working interest in AOSP to 90%, adding approximately 62,500 bbl/d of long life no decline SCO production to our portfolio.
  - Production net to Canadian Natural from the Duvernay assets is targeted to average approximately 60,000 BOE/d in 2025.
  - The effective date for these acquisitions is September 1, 2024 and is targeted to close in Q4/24.

RETURNS TO SHAREHOLDERS

- Returns to shareholders in Q3/24 were strong, totaling approximately $1.9 billion, comprised of $1.12 billion of dividends and $0.74 billion through the repurchase and cancellation of approximately 15.6 million common shares at a weighted average price of $47.70 per share.
  - Year to date in 2024, up to and including October 30, 2024, the Company has returned a total of approximately $6.7 billion directly to shareholders through $4.4 billion in dividends and $2.3 billion through the repurchase and cancellation of approximately 47.6 million common shares.

- Free cash flow is defined as adjusted funds flow, less capital and dividends. The Company will manage the allocation of free cash flow on a forward looking annual basis, while managing working capital and cash management as required. As previously disclosed on October 7, 2024 and subsequent to quarter end, the Board of Directors has adjusted the free cash flow allocation policy which will now be allocated as follows:
  - 60% of free cash flow to shareholder returns and 40% to the balance sheet until net debt reaches $15 billion.
  - When net debt is between $12 billion and $15 billion, free cash flow allocation will be 75% to shareholder returns and 25% to the balance sheet.
  - When net debt is at or below $12 billion, up from the current target of $10 billion, free cash flow allocation will be 100% to shareholder returns.
- Post closing of the acquisitions previously disclosed on October 7, 2024, the Company will target to allocate 60% of free cash flow to shareholders. In a US$70/bbl WTI environment this change in free cash flow distribution to 60% allocation to shareholders targets to be approximately the equivalent absolute return to shareholders, including dividends, of what was targeted under the 100% of free cash flow allocation to shareholders existing prior to the acquisitions. Due to the additional free cash flow generation from the acquired assets, the Company's balance sheet strengthens quickly. Over time, the acquisitions and the new free cash flow allocation policy will provide additional free cash flow returns to shareholders exceeding what would have been returned under the current 100% distribution of free cash flow to shareholders.
- As previously disclosed on October 7, 2024 and subsequent to quarter end, the Board of Directors has agreed to increase the quarterly cash dividend by 7% to $0.5625 per common share, an increase from $0.525 per common share. The dividend will be payable on January 3, 2025 to shareholders of record at the close of business on December 13, 2024. This will mark 2025 as the 25th consecutive year of dividend increases by Canadian Natural, with a CAGR of 21% over that time.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the Company's MD&A for the three and nine months ended September 30, 2024 dated October 30, 2024.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK section of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light crude oil, medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil) and SCO (herein collectively referred to as "crude oil") and natural gas and NGLs. This balance provides optionality for capital investments, maximizing value for the Company's shareholders.

Underpinning this asset base is the Company's long life low decline production, representing approximately 79% of total budgeted liquids production in 2024, the majority of which is zero decline high value SCO production from the Company's world class Oil Sands Mining and Upgrading assets. The remaining balance of the Company's long life low decline production comes from its top tier thermal in situ oil sands operations and Pelican Lake heavy crude oil assets. The combination of these long life low decline assets, low reserves replacement costs, and effective and efficient operations results in substantial and sustainable adjusted funds flow throughout the commodity price cycle.

In addition, Canadian Natural maintains a substantial inventory of low capital exposure projects within the Company's conventional asset base. These projects can be executed quickly and, in the right economic conditions, provide excellent returns and maximize value for our shareholders. Supporting these projects is the Company's undeveloped landbase which enables large, repeatable drilling programs that can be optimized over time. Additionally, Canadian Natural maximizes long-term value by maintaining high ownership and operatorship of its assets, allowing the Company to control the nature, timing and extent of development. Low capital exposure projects can be stopped or started relatively quickly depending upon success, market conditions or corporate needs.

Canadian Natural's balanced portfolio, built with both long life low decline assets and low capital exposure assets, enables effective capital allocation, production growth and value creation.

Drilling Activity

	Nine Months Ended			
	Sep 30, 2024		Sep 30, 2023	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [1]	**212**	**207**	186	179
Natural gas	**77**	**64**	61	52
Dry	**2**	**2**	2	2
Subtotal	**291**	**273**	249	233
Stratigraphic test / service wells	**460**	**394**	476	414
Total	**751**	**667**	725	647
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 273 net crude oil and natural gas producer wells in the first nine months of 2024, consistent with the Company's strategic decision to focus on longer cycle development opportunities in the first half of 2024. Canadian Natural has strategically allocated capital to its conventional heavy crude oil assets in the second half of 2024.
- In Q1/24, the Company disclosed the reallocation of capital from certain dry natural gas development activity to multilateral heavy crude oil wells.
  - Due to low natural gas prices in 2024, the Company has further reduced dry natural gas drilling activity. Canadian Natural now targets to drill a total of 74 net natural gas wells in 2024, 17 fewer wells than targeted in the original 2024 budget.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs production (bbl/d)	**228,221**	231,592	232,496	**232,416**	231,047
Net wells targeting crude oil	**59**	33	42	**130**	131
Net successful wells drilled	**58**	33	42	**129**	129
Success rate	**98%**	100%	100%	**99%**	98%

- North America E&P liquids production, excluding thermal in situ, averaged 228,221 bbl/d in Q3/24, comparable to Q3/23 levels, reflecting primary heavy crude oil development activity offset by natural field declines. The Company has strategically allocated capital to its conventional heavy crude oil assets in the second half of 2024.
  - Primary heavy crude oil production averaged 76,808 bbl/d in Q3/24, a 1% increase from Q3/23 levels due to strong drilling results from the Company's multilateral well program offset by natural field declines.
    - Operating costs[(1)] in the Company's primary heavy crude oil operations averaged $18.69/bbl (US$13.70/bbl) in Q3/24, a decrease of 5% from Q3/23 levels, primarily reflecting lower energy costs.
    - The Company operates the largest heavy crude oil landbase in Canada. We continue to maximize the value of this premium asset through our multilateral drilling program. As a result of optimized longer well designs and the technical expertise of our teams, the Company continued to deliver strong results in Q3/24.
      - In the first nine months of 2024, the company drilled 76 net multilateral wells, maintaining top tier average initial peak rates of approximately 230 bbl/d per well, an increase of approximately 30% compared to budget average initial peak rates of 175 bbl/d per well.
  - Pelican Lake production averaged 45,101 bbl/d in Q3/24, a decrease of 4% from Q3/23 levels, reflecting low natural field declines from this long life low decline asset.
    - Operating costs at Pelican Lake averaged $8.74/bbl (US$6.41/bbl) in Q3/24, an increase of 9% compared to Q3/23 levels, primarily due to higher maintenance activities in the quarter partially offset by lower energy costs.
  - North America light crude oil and NGLs production averaged 106,312 bbl/d in Q3/24, a decrease of 3% from Q3/23 levels. The decrease was primarily the result of temporary processing facility outages and rail transportation restrictions offset by strong drilling results.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged $13.73/bbl (US$10.07/bbl) in Q3/24, a decrease of 11% from Q3/23 levels, primarily reflecting lower energy costs.

North America Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Natural gas production (MMcf/d)	**2,039**	2,099	2,139	**2,091**	2,113
Net wells targeting natural gas	**24**	25	10	**65**	52
Net successful wells drilled	**24**	24	10	**64**	52
Success rate	**100%**	96%	100%	**98%**	100%

- Canadian Natural's North America natural gas production averaged 2,039 MMcf/d in Q3/24, a decrease of 5% compared to Q3/23, primarily reflecting previously announced deferrals of natural gas well onstream timing in response to natural gas pricing, the impacts of heat and wildfires conditions in Q3/24 and natural field declines. This decrease in production was partially offset by strong results from our Montney and Deep Basin wells.
  - North America natural gas operating costs averaged $1.23/Mcf in Q3/24, comparable to Q3/23 levels.

(1) Calculated as production expense divided by respective sales volumes. Natural gas and NGLs production volumes approximate sales volumes.

- In Q1/24, the Company disclosed the reallocation of capital from certain dry natural gas development activity to multilateral heavy oil wells.
  - Due to continued low natural gas prices in 2024, the Company is further reducing dry natural gas drilling capital. Canadian Natural now targets drilling a total of 74 net natural gas wells in 2024, 17 fewer wells than targeted in the original 2024 budget.
  - Canadian Natural's 2024 corporate annual natural gas production guidance of 2,120 MMcf/d to 2,230 MMcf/d remains unchanged.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Bitumen production (bbl/d)	**271,551**	268,044	287,085	**269,258**	256,466
Net wells targeting bitumen	**25**	30	2	**78**	50
Net successful wells drilled	**25**	30	2	**78**	50
Success rate	**100%**	100%	100%	**100%**	100%

- Thermal in situ long life low decline production averaged 271,551 bbl/d in Q3/24, a decrease of 5% from Q3/23 levels, primarily due to the cyclical nature of production from CSS pads at Primrose and natural field declines, partially offset by thermal SAGD pad additions at Kirby and Jackfish.
  - Thermal in situ operating costs were strong, averaging $10.52/bbl (US$7.71/bbl) in Q3/24, a decrease of 8% from Q3/23 levels, primarily reflecting lower energy costs.
- Canadian Natural has decades of strong capital efficient growth opportunities on its long life low decline thermal in situ assets. As per our 2024 budget, we continue to develop these assets in a disciplined manner to deliver safe and reliable thermal in situ production including the following updates:
  - At Jackfish, the Company achieved record quarterly production of approximately 128,000 bbl/d in Q3/24, primarily due to strong results from pad additions and effective and efficient operations. Additionally, the Company is currently drilling a SAGD pad at Jackfish with production from this pad targeted to come on in Q3/25.
  - At Wolf Lake, the Company recently drilled a SAGD pad which is targeted to come on production in Q4/24 and as a result of strong execution will reach full production capacity in Q1/25, one quarter ahead of schedule.
  - At Primrose, the Company targets to bring a CSS pad on production ahead of schedule in Q4/24, originally targeted for Q2/25. A second CSS pad has been drilled and is targeted to come on production ahead of schedule in Q1/25, originally budgeted for Q2/25.
- 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 Steam to Oil Ratio ("SOR") and optimizing solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - At the Company's commercial scale solvent SAGD pad at Kirby North, we began solvent injection in June 2024 and all 8 wells are now injecting solvent. Early results have been positive with SOR reductions of approximately 30%, trending towards a targeted reduction of 40% to 50%. Solvent recoveries are in excess of 85% and are meeting expectations. As the project advances, the Company will continue to monitor SORs, solvent recovery and production trends.
  - At Primrose, the Company is continuing to operate its solvent enhanced oil recovery pilot in the steam flood area to optimize solvent efficiency and to further evaluate this commercial development opportunity.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Synthetic crude oil production (bbl/d) (1)(2)	**497,656**	410,518	490,853	**451,298**	434,895

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

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

- The Company's world class Oil Sands Mining and Upgrading assets delivered strong production averaging 497,656 bbl/d of high value SCO in Q3/24, approximately 7,000 bbl/d higher than Q3/23 levels. These quarterly production volumes in Q3/24 included the impacts of planned turnaround activities at the non-operated Scotford Upgrader.
  - Oil Sands Mining and Upgrading achieved a new monthly production record of approximately 529,000 bbl/d of SCO in August 2024. This was primarily due to high utilization at both Horizon and AOSP as well as the completion of the reliability enhancement project at Horizon during the planned turnaround in Q2/24.
  - Oil Sands Mining and Upgrading operating costs continue to be top tier, averaging $20.67/bbl (US$15.16/bbl) in Q3/24, a decrease of 7% from Q3/23 levels, primarily reflecting higher production volumes and lower energy costs.
  - Due to stronger than budgeted production volumes at the Scotford Upgrader concurrent with reduced duration of the planned turnaround, the annual net production impact to AOSP from these planned turnaround activities was reduced to approximately 5,400 bbl/d, a significant improvement compared to the budgeted annual net production impact of 11,000 bbl/d. The planned turnaround commenced on September 9, 2024 and was successfully completed subsequent to quarter end on October 18, 2024.
  - Additionally, a debottlenecking project was completed during the planned turnaround at the Scotford Upgrader which increases gross AOSP capacity by approximately 8,000 bbl/d. Upon closing the acquisition of Chevron's 20% interest in AOSP, the capacity net to Canadian Natural increases to approximately 7,200 bbl/d.
- At Horizon, the Company is progressing the NRUTT project which targets to add incremental production of approximately 6,300 bbl/d of SCO following mechanical completion in Q3/27.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil production (bbl/d)	**24,144**	23,912	24,719	**24,293**	26,180
Natural gas production (MMcf/d)	**10**	11	12	**11**	12

- International E&P crude oil production volumes averaged 24,144 bbl/d in Q3/24, comparable to Q3/23 levels.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Benchmark Commodity Prices					
WTI benchmark price (US$/bbl) [1]	**$ 75.16**	$ 80.55	$ 82.18	**$ 77.55**	$ 77.37
WCS heavy differential (discount) to WTI (US$/bbl) [1]	**$ (13.51)**	$ (13.54)	$ (12.86)	**$ (15.46)**	$ (17.51)
WCS heavy differential as a percentage of WTI (%) [1]	**18%**	17%	16%	**20%**	23%
Condensate benchmark price (US$/bbl)	**$ 71.24**	$ 77.11	$ 77.91	**$ 73.71**	$ 76.66
SCO price (US$/bbl) [1]	**$ 76.51**	$ 83.33	$ 84.99	**$ 76.42**	$ 79.97
SCO premium (discount) to WTI (US$/bbl) [1]	**$ 1.35**	$ 2.78	$ 2.81	**$ (1.13)**	$ 2.60
AECO benchmark price (C$/GJ)	**$ 0.77**	$ 1.36	$ 2.26	**$ 1.35**	$ 2.86
Realized Prices					
Exploration & Production liquids realized price (C$/bbl) [2][3][4][5]	**$ 79.15**	$ 86.64	$ 87.83	**$ 78.67**	$ 73.45
SCO realized price (C$/bbl) [1][3][4][5]	**$ 100.93**	$ 108.81	$ 108.55	**$ 99.19**	$ 100.57
Natural gas realized price (C$/Mcf) [4]	**$ 1.25**	$ 1.59	$ 2.81	**$ 1.80**	$ 3.20

(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 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 for the three and nine months ended September 30, 2024 dated October 30, 2024.

- Canadian Natural has a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, bitumen and SCO.
- WTI prices averaged US$75.16/bbl in Q3/24, a decrease of US$7.02/bbl compared to Q3/23, primarily reflecting weaker global demand concerns.
- SCO pricing averaged US$76.51/bbl in Q3/24, representing a US$1.35/bbl price premium to WTI, compared to a US$2.81/bbl price premium to WTI in Q3/23.
- The WCS differential to WTI averaged US$13.51/bbl, widening by US$0.65/bbl in Q3/24, compared to US$12.86/bbl in Q3/23, primarily reflecting lower heavy crude oil demand as a result of planned and unplanned outages at two US mid-west refineries.
- The North West Redwater ("NWR") refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 72,109 bbl/d in Q3/24.
- During 2024, the Company has increased its contracted crude oil transportation capacity to 256,500 bbl/d, expanding its committed volumes to Canada's West Coast and to the USGC to approximately 25% of liquids production compared to the mid-point of 2024 corporate annual guidance. The additional egress supports Canadian Natural's long-term sales strategy by targeting expanded refining markets, driving stronger netbacks while also reducing exposure to egress constraints.
    - Commencing December 1, 2024, the Company will increase its capacity on the TMX pipeline by 75,000 bbl/d to a total of 169,000 bbl/d.
    - As previously disclosed, the Company increased its capacity on the Flanagan South pipeline in Q1/24 by 55,000 bbl/d to a total of 77,500 bbl/d, further expanding the Company's heavy oil diversification and market access to the USGC.
    - The Company also has committed volumes of 10,000 bbl/d on the Keystone Base pipeline, with direct access to the USGC.
- AECO natural gas prices averaged $0.77/GJ in Q3/24, significantly lower compared to Q3/23 primarily reflecting lower NYMEX benchmark pricing, combined with high storage inventories resulting from weaker demand and increased production levels in the Western Canadian Sedimentary Basin ("WCSB").

- In 2024, the Company is targeting to use the equivalent of approximately 38% of its budgeted natural gas production in its operations, with approximately 25% targeted to be sold at AECO/Station 2 pricing, and approximately 37% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value from its diversified natural gas marketing portfolio.

SUSTAINABILITY HIGHLIGHTS

Canadian Natural's diverse portfolio is supported by a large amount of long life low decline assets which have low risk, high value reserves that require low maintenance capital. This allows us to remain flexible with our capital allocation and creates an ideal opportunity to pilot and apply technologies. Canadian Natural continues to invest in a range of technologies like solvents for enhanced recovery and Carbon Capture, Utilization and Storage ("CCUS") projects. Our culture of continuous improvement provides a significant advantage to delivering on our strategy of investing in technologies across our assets, which will enhance the Company’s long-term sustainability.

In June 2024, the Canadian Government amended the *Competition Act*, resulting in changes to the law around environmental communications. As we look to communicate the important work we are doing to protect the environment or helping to address climate change, there is uncertainty on how this new legislation will be interpreted and applied on a go forward basis. We regret that we are unable to provide an environment and climate update at this time. This legislation does not change our commitment to the environment and to ensuring safe, reliable operations, only the way in which we are publicly communicating these aspects of our business. As we receive additional guidance, we intend to resume environmental and climate-related disclosure.

While we wait for clarity on this legislation, we are proud to share Canadian Natural’s performance in governance, workplace and process safety, and our contributions to people, community and partnerships. Our 2023 Stewardship Report to Stakeholders, which can be found at www.cnrl.com, displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while enhancing our world-class assets by innovating and leveraging technology, and driving continuous improvement across our teams. These efforts include building shared value with communities and Indigenous groups in our operating areas.

Highlights from the Company's 2023 report include:

- 50% reduction in total recordable injury frequency ("TRIF") and a 75% reduction in corporate lost time incident frequency ("LTI") from 2019 to 2023.
- $502 million invested in research, technology development and deployment in 2023.
- 2.7 million tonnes of CO_2e per year total carbon capture capacity.
- $830 million in contracts secured with Indigenous businesses, a 21% increase from 2022.
- Approximately $9 billion in payments to governments and local communities in 2023 through royalties, corporate taxes, property taxes and surface and mineral land leases.

ADVISORY

Special Note Regarding Non-GAAP and Other Financial Measures

This document 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. These financial measures are used by the Company to evaluate its financial performance, financial position or 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 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 Company's 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 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 nine months ended September 30, 2024, dated October 30, 2024.

Capital Budget

Capital budget is a forward looking non-GAAP financial measure. The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

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.

Free Cash Flow Policy in 2023 and 2024 (before the closing of the agreement to acquire Chevron's Alberta assets, targeted to close in Q4/24. Upon closing, the free cash flow policy will change as disclosed in the press release dated October 7, 2024.)

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 target amount of shareholder returns after dividends. The calculation in determining free cash flow varies depending on the Company's net debt position, and as a result of achieving $10 billion in net debt at the end of 2023, the Company's free cash flow calculation has changed in 2024, when compared to 2023 as follows:

- **Allocation of Free Cash Flow in 2024**

  As net debt of $10 billion was achieved at the end of 2023, commencing in 2024, the Company will target to return 100% of free cash flow to shareholders. 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 management as required.

  The Company's free cash flow for the three and nine months ended September 30, 2024 is shown below:

($ millions)	Three Months Ended Sep 30 2024	Three Months Ended Jun 30 2024	Nine Months Ended Sep 30 2024
Adjusted funds flow (1)	**$ 3,921**	$ 3,614	**$ 10,673**
Less: Dividends on common shares	**1,118**	1,125	**3,319**
Net capital expenditures (2)	**1,349**	1,621	**4,083**
Abandonment expenditures	**204**	129	**495**
Free cash flow	**$ 1,250**	$ 739	**$ 2,776**

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2024, dated October 30, 2024.

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and nine months ended September 30, 2024, dated October 30, 2024.

- **Allocation of Free Cash Flow in 2023**

  When net debt was between $10 billion and $15 billion, as was the case in 2023, approximately 50% of free cash flow was allocated to shareholder returns and 50% was allocated to the balance sheet, less strategic growth/acquisition opportunities. In 2023, free cash flow of $6.9 billion was calculated as adjusted funds flow of $15.3 billion less dividends on common shares of $3.9 billion, base capital expenditures of $4.0 million and abandonment expenditures of $0.5 billion.

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, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, 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 regarding the agreement to acquire from Chevron Canada Limited or its affiliates (collectively, "Chevron"), of its 20% interest in the Athabasca Oil Sands Project ("AOSP"), its 70% operated working interest in the Duvernay asset play, as well as additional working interests in certain other non-producing oil sands leases, hereinafter referred to as the "agreement to acquire assets from Chevron", including the anticipated closing thereof, including the impact of such acquisitions on the Company's debt to book capitalization ratio, and 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"), 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 bitumen, crude oil, 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 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, 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, the impact of the Russian invasion of Ukraine, 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, natural gas and NGLs 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; political uncertainty, including 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 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, including the agreement to acquire assets from Chevron; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; 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, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. 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 Common Share Split and Comparative Figures

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

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. These amendments include substantial financial penalties and, effective June 20, 2025, a private right of action which will permit private parties to seek an order from the Competition Tribunal under the deceptive marketing practices provisions. Uncertainty surrounding the interpretation and enforcement of this legislation 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 nine months ended September 30, 2024, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2023. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three and nine months ended September 30, 2024 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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, bitumen (thermal oil), and SCO. Production on an "after royalties" or "company net" basis is also presented for information purposes only. Further, results from operations for the three and nine months ended September 30, 2024 and all guidance amounts presented in this MD&A exclude the impact of the agreement to acquire assets from Chevron.

The following discussion and analysis refers primarily to the Company's financial results for the three and nine months ended September 30, 2024 in relation to the comparable periods in 2023 and the second quarter of 2024. 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, 2023, 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 October 30, 2024.

FINANCIAL HIGHLIGHTS[1]

($ millions, except per common share amounts)		Three Months Ended Sep 30 2024	Jun 30 2024	Sep 30 2023	Nine Months Ended Sep 30 2024	Sep 30 2023
Product sales [1]		**$ 10,401**	$ 10,622	$ 11,762	**$ 30,445**	$ 30,156
Crude oil and NGLs		**$ 9,943**	$ 10,084	$ 10,944	**$ 28,703**	$ 27,471
Natural gas		**$ 257**	$ 331	$ 599	**$ 1,117**	$ 1,972
Net earnings		**$ 2,266**	$ 1,715	$ 2,344	**$ 4,968**	$ 5,606
Per common share	– basic	**$ 1.07**	$ 0.80	$ 1.08	**$ 2.33**	$ 2.56
	– diluted	**$ 1.06**	$ 0.80	$ 1.06	**$ 2.31**	$ 2.53
Adjusted net earnings from operations [2]		**$ 2,071**	$ 1,892	$ 2,850	**$ 5,437**	$ 5,987
Per common share	– basic [3]	**$ 0.98**	$ 0.89	$ 1.31	**$ 2.55**	$ 2.73
	– diluted [3]	**$ 0.97**	$ 0.88	$ 1.30	**$ 2.53**	$ 2.71
Cash flows from operating activities		**$ 3,002**	$ 4,084	$ 3,498	**$ 9,954**	$ 7,538
Adjusted funds flow [2]		**$ 3,921**	$ 3,614	$ 4,684	**$ 10,673**	$ 10,855
Per common share	– basic [3]	**$ 1.85**	$ 1.69	$ 2.15	**$ 5.01**	$ 4.96
	– diluted [3]	**$ 1.84**	$ 1.68	$ 2.13	**$ 4.97**	$ 4.91
Cash flows used in investing activities		**$ 1,274**	$ 1,015	$ 1,199	**$ 3,681**	$ 3,912
Net capital expenditures [4]		**$ 1,349**	$ 1,621	$ 1,108	**$ 4,083**	$ 3,934
Abandonment expenditures		**$ 204**	$ 129	$ 123	**$ 495**	$ 360

(1) Further details related to product sales are disclosed in note 18 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.
(4) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2023 and has been updated for all periods presented. 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 nine months ended September 30, 2024 were $4,968 million compared with $5,606 million for the nine months ended September 30, 2023. Net earnings for the nine months ended September 30, 2024 included non-operating losses, net of tax, of $469 million compared with non-operating losses of $381 million for the nine months ended September 30, 2023 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on the repayment of US dollar debt securities, the gain from investment, and a recoverability charge related to the notice to withdraw from Block 11B/12B in South Africa. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2024 were $5,437 million compared with $5,987 million for the nine months ended September 30, 2023.

Net earnings for the third quarter of 2024 were $2,266 million compared with $2,344 million for the third quarter of 2023 and $1,715 million for the second quarter of 2024. Net earnings for the third quarter of 2024 included non-operating income, net of tax, of $195 million compared with non-operating losses of $506 million for the third quarter of 2023 and non-operating losses of $177 million for the second quarter of 2024 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on the repayment of US dollar debt securities, the loss (gain) from investments, and a recoverability charge related to the notice to withdraw from Block 11B/12B in South Africa. Excluding these items, adjusted net earnings from operations for the third quarter of 2024 were $2,071 million compared with $2,850 million for the third quarter of 2023 and $1,892 million for the second quarter of 2024.

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the Advisory section of this MD&A and in note 1 of the financial statements.

The decrease in net earnings and adjusted net earnings from operations for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 primarily reflected:

- lower natural gas pricing in the North America Exploration and Production segment;

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher crude oil and NGLs sales volumes and netbacks[1] in the North America Exploration and Production segment.

The decrease in net earnings and adjusted net earnings from operations for the third quarter of 2024 from the third quarter of 2023 primarily reflected:

- lower crude oil and NGLs sales volumes and netbacks in the North America Exploration and Production segment;
- lower natural gas pricing in the North America Exploration and Production segment; and
- lower realized SCO pricing[1] in the Oil Sands Mining and Upgrading segment.

The increase in net earnings and adjusted net earnings from operations for the third quarter of 2024 from the second quarter of 2024 primarily reflected:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;

partially offset by:

- lower crude oil and NGLs sales volumes and netbacks in the North America Exploration and Production segment; and
- lower realized SCO pricing in the Oil Sands Mining and Upgrading segment.

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange (gain) loss, and the loss (gain) from investment also contributed to the movements in net earnings. 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 nine months ended September 30, 2024 were $9,954 million compared with $7,538 million for the nine months ended September 30, 2023. Cash flows from operating activities for the third quarter of 2024 were $3,002 million compared with $3,498 million for the third quarter of 2023 and $4,084 million for the second quarter of 2024. The fluctuations in cash flows from operating activities from the comparable periods was 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 nine months ended September 30, 2024 was $10,673 million compared with $10,855 million for the nine months ended September 30, 2023. Adjusted funds flow for the third quarter of 2024 was $3,921 million compared with $4,684 million for the third quarter of 2023 and $3,614 million for the second quarter of 2024. The fluctuations in adjusted funds flow from the comparable periods was 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 the share bonus program, accrued interest on the deferred Petroleum Revenue Tax ("PRT") recovery, and prepaid cost of service tolls.

Production Volumes

Crude oil and NGLs production before royalties for the third quarter of 2024 of 1,021,572 bbl/d was comparable with 1,035,153 bbl/d for the third quarter of 2023 and increased 9% from 934,066 bbl/d for the second quarter of 2024. Natural gas production before royalties for the third quarter of 2024 of 2,049 MMcf/d decreased 5% from 2,151 MMcf/d for the third quarter of 2023 and decreased 3% from 2,110 MMcf/d for the second quarter of 2024. Total production before royalties for the third quarter of 2024 of 1,363,086 BOE/d was comparable with 1,393,614 BOE/d for the third quarter of 2023 and increased 6% from 1,285,798 BOE/d for the second quarter of 2024. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

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

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices[1] averaged $79.15 per bbl for the third quarter of 2024, a decrease of 10% from $87.83 per bbl for the third quarter of 2023, and a decrease of 9% from $86.64 per bbl for the second quarter of 2024. The realized natural gas price decreased 56% to average $1.25 per Mcf for the third quarter of 2024 from $2.81 per Mcf for the third quarter of 2023 and decreased 21% from $1.59 per Mcf for the second quarter of 2024. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 7% to average $100.93 per bbl for the third quarter of 2024 from $108.55 per bbl for the third quarter of 2023 and decreased 7% from $108.81 per bbl for the second quarter of 2024. The Company's realized pricing reflected 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 the "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[2] averaged $14.65 per bbl for the third quarter of 2024, comparable with $14.40 per bbl for the third quarter of 2023 and $14.54 per bbl for the second quarter of 2024. Natural gas production expense[2] averaged $1.26 per Mcf for the third quarter of 2024, comparable with $1.25 per Mcf for the third quarter of 2023, and an increase of 4% from $1.21 per Mcf for the second quarter of 2024. In the Oil Sands Mining and Upgrading segment, production expense[2] averaged $20.67 per bbl for the third quarter of 2024, a decrease of 7% from $22.12 per bbl for the third quarter of 2023, and a decrease of 20% from $25.95 per bbl for the second quarter of 2024. Crude oil and NGLs and natural gas production expense is discussed in detail in the "Production Expense – Exploration and Production" and the "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)		**Sep 30 2024**		Jun 30 2024		Mar 31 2024		Dec 31 2023
Product sales [1]	**$**	**10,401**	$	10,622	$	9,422	$	10,679
Crude oil and NGLs	**$**	**9,943**	$	10,084	$	8,676	$	9,829
Natural gas	**$**	**257**	$	331	$	529	$	603
Net earnings	**$**	**2,266**	$	1,715	$	987	$	2,627
Net earnings per common share [2]								
– basic	**$**	**1.07**	$	0.80	$	0.46	$	1.22
– diluted	**$**	**1.06**	$	0.80	$	0.46	$	1.21

($ millions, except per common share amounts)		Sep 30 2023		Jun 30 2023		Mar 31 2023		Dec 31 2022
Product sales [1]	$	11,762	$	8,846	$	9,548	$	11,012
Crude oil and NGLs	$	10,944	$	8,115	$	8,412	$	9,508
Natural gas	$	599	$	522	$	851	$	1,287
Net earnings	$	2,344	$	1,463	$	1,799	$	1,520
Net earnings per common share [2]								
– basic	$	1.08	$	0.67	$	0.82	$	0.69
– diluted	$	1.06	$	0.66	$	0.81	$	0.68

(1) Further details related to product sales for the three months ended September 30, 2024 and 2023 are disclosed in note 18 to the financial statements.

(2) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the Advisory section of this MD&A and in note 1 of the financial statements.

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

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

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 Russian invasion of Ukraine and conflict in the Middle East) on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the start-up of the Trans Mountain Expansion ("TMX") pipeline, 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, and the impact of shale gas production in the US.
- **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 decline rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, wildfires and a third-party pipeline outage in 2023 in the North America Exploration and Production segment. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in the North America Exploration and Production segment, natural field decline rates, the impact of seasonal conditions, wildfires, and a third-party pipeline outage in 2023 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, increased carbon tax, fluctuating energy costs, inflationary cost pressures, cost optimizations across all segments, turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization expense** – Fluctuations due to changes in sales volumes, 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 and pitstops in the Oil Sands Mining and Upgrading segment, a recoverability charge at June 30, 2024 relating to the notice to withdraw from Block 11B/12B in South Africa, a recoverability charge at December 31, 2023 relating to the increase in estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea, and a recoverability charge at December 31, 2022 relating to the de-booking of reserves at the Ninian field in the North Sea.
- **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 the impact of movements in benchmark interest rates on outstanding floating rate long-term debt and accrued interest on the deferred PRT recovery.
- **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.
- **Loss (gain) from investment** – Fluctuations due to the loss (gain) from the Company's investment in PrairieSky Royalty Ltd. shares.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing declined in the third quarter of 2024 as a result of weaker global demand growth. Additionally, supply quota management by OPEC+ and geopolitical tensions in the Middle East led to continued volatility in pricing. The start-up of the TMX pipeline in the second quarter of 2024 contributed to a narrowing of the WCS differential with benefit to the Company's realized product pricing in 2024. Natural gas prices continued to decline as a result of high storage levels in 2024. Although inflationary pressures are easing, the Company has experienced and may continue to experience inflationary pressures on its operating and capital expenditures in addition to higher than normal fluctuations in commodity prices and interest rates.

Liquidity

As at September 30, 2024, the Company had undrawn revolving bank credit facilities of $5,450 million. Including cash and cash equivalents, the Company had approximately $6,171 million in liquidity[(1)]. The Company also has certain other dedicated credit facilities supporting letters of credit.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity, and a flexible capital structure. Refer to the "Liquidity and Capital Resources" section of this MD&A for further details.

Benchmark Commodity Prices

	Three Months Ended			Nine Months Ended	
(Average for the period)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
WTI benchmark price (US$/bbl)	**$ 75.16**	$ 80.55	$ 82.18	**$ 77.55**	$ 77.37
Dated Brent benchmark price (US$/bbl)	**$ 80.25**	$ 84.90	$ 86.68	**$ 82.78**	$ 82.11
WCS Heavy Differential from WTI (US$/bbl)	**$ 13.51**	$ 13.54	$ 12.86	**$ 15.46**	$ 17.51
SCO price (US$/bbl)	**$ 76.51**	$ 83.33	$ 84.99	**$ 76.42**	$ 79.97
Condensate benchmark price (US$/bbl)	**$ 71.24**	$ 77.11	$ 77.91	**$ 73.71**	$ 76.66
NYMEX benchmark price (US$/MMBtu)	**$ 2.16**	$ 1.89	$ 2.55	**$ 2.10**	$ 2.69
AECO benchmark price (C$/GJ)	**$ 0.77**	$ 1.36	$ 2.26	**$ 1.35**	$ 2.86
US/Canadian dollar average exchange rate (US$)	**$ 0.7332**	$ 0.7308	$ 0.7456	**$ 0.7351**	$ 0.7432

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company’s realized prices are directly impacted by fluctuations in foreign exchange rates resulting in product revenues being impacted by changes in Canadian dollar sales prices relative to the US dollar benchmark prices.

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US$77.55 per bbl for the nine months ended September 30, 2024, comparable with US$77.37 per bbl for the nine months ended September 30, 2023. WTI averaged US$75.16 per bbl for the third quarter of 2024, a decrease of 9% from US$82.18 per bbl for the third quarter of 2023, and a decrease of 7% from US$80.55 per bbl for the second quarter of 2024.

Crude oil sales contracts for the Company's International segments are typically based on Brent pricing, which is representative of international markets and overall global supply and demand. Brent averaged US$82.78 per bbl for the nine months ended September 30, 2024, comparable with US$82.11 per bbl for the nine months ended September 30, 2023. Brent averaged US$80.25 per bbl for the third quarter of 2024, a decrease of 7% from US$86.68 per bbl for the third quarter of 2023, and a decrease of 5% from US$84.90 per bbl for the second quarter of 2024.

The decrease in WTI and Brent benchmark pricing for the third quarter of 2024 from the comparable periods primarily reflected weaker global demand growth. Additionally, supply quota management by OPEC+, and geopolitical tensions in the Middle East led to continued volatility in the third quarter of 2024.

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

The WCS Heavy Differential averaged US$15.46 per bbl for the nine months ended September 30, 2024, compared with US$17.51 per bbl for the nine months ended September 30, 2023. The WCS Heavy Differential averaged US$13.51 per bbl for the third quarter of 2024, compared with US$12.86 per bbl for the third quarter of 2023, and US$13.54 per bbl for the second quarter of 2024. The narrowing of the WCS Heavy Differential for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 primarily reflected the start-up of the TMX pipeline in the second quarter of 2024, combined with stronger US Gulf Coast heavy oil pricing. The widening of the WCS Heavy Differential for the third quarter of 2024 from the third quarter of 2023 primarily reflected planned and unplanned refinery outages in the US Midwest as well as weakening US Gulf Coast heavy oil pricing.

The SCO price averaged US$76.42 per bbl for the nine months ended September 30, 2024, a decrease of 4% from US$79.97 per bbl for the nine months ended September 30, 2023. The SCO price averaged US$76.51 per bbl for the third quarter of 2024, a decrease of 10% from US$84.99 per bbl for the third quarter of 2023, and a decrease of 8% from US$83.33 per bbl for the second quarter of 2024. The decrease in SCO pricing for the three and nine months ended September 30, 2024 from the comparable periods primarily reflected WTI benchmark pricing and weaker diesel pricing.

NYMEX natural gas prices averaged US$2.10 per MMBtu for the nine months ended September 30, 2024, a decrease of 22% from US$2.69 per MMBtu for the nine months ended September 30, 2023. NYMEX natural gas prices averaged US$2.16 per MMBtu for the third quarter of 2024, a decrease of 15% from US$2.55 per MMBtu for the third quarter of 2023, and an increase of 14% from US$1.89 per MMBtu for the second quarter of 2024. The decrease in NYMEX natural gas prices for the three and nine months ended September 30, 2024 from the comparable periods in 2023 primarily reflected high North American and European inventory levels following mild winter weather in 2024. The increase in NYMEX natural gas pricing for the third quarter of 2024 from the second quarter of 2024 reflected seasonal demand factors with warm third quarter temperatures and lower US production levels.

AECO natural gas prices averaged $1.35 per GJ for the nine months ended September 30, 2024, a decrease of 53% from $2.86 per GJ for the nine months ended September 30, 2023. AECO natural gas prices averaged $0.77 per GJ for the third quarter of 2024, a decrease of 66% from $2.26 per GJ for the third quarter of 2023, and a decrease of 43% from $1.36 per GJ for the second quarter of 2024. The decrease in AECO natural gas prices for the three and nine months ended September 30, 2024 from the comparable periods in 2023 reflected NYMEX benchmark pricing, combined with high storage inventories resulting from weaker demand and increased production levels in the Western Canadian Sedimentary Basin. Similarly, the decrease for the third quarter of 2024 from the second quarter of 2024 primarily reflected high inventory levels resulting from weaker seasonal demand.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**499,772**	499,636	519,581	**501,674**	487,512
North America – Oil Sands Mining and Upgrading (1)	**497,656**	410,518	490,853	**451,298**	434,895
International – Exploration and Production					
North Sea	**10,958**	11,295	12,016	**11,560**	12,647
Offshore Africa	**13,186**	12,617	12,703	**12,733**	13,533
Total International (2)	**24,144**	23,912	24,719	**24,293**	26,180
Total Crude oil and NGLs	**1,021,572**	934,066	1,035,153	**977,265**	948,587
Natural gas (MMcf/d) (3)					
North America	**2,039**	2,099	2,139	**2,091**	2,113
International					
North Sea	**1**	2	1	**1**	2
Offshore Africa	**9**	9	11	**10**	10
Total International	**10**	11	12	**11**	12
Total Natural gas	**2,049**	2,110	2,151	**2,102**	2,125
Total Barrels of oil equivalent (BOE/d)	**1,363,086**	1,285,798	1,393,614	**1,327,593**	1,302,715
Product mix					
Light and medium crude oil and NGLs	**9%**	10%	10%	**10%**	10%
Pelican Lake heavy crude oil	**3%**	4%	3%	**3%**	4%
Primary heavy crude oil	**6%**	6%	5%	**6%**	6%
Bitumen (thermal oil)	**20%**	21%	21%	**20%**	20%
Synthetic crude oil (1)	**37%**	32%	35%	**34%**	33%
Natural gas	**25%**	27%	26%	**27%**	27%
Percentage of product sales (1) (4) (5)					
Crude oil and NGLs	**97%**	97%	95%	**96%**	93%
Natural gas	**3%**	3%	5%	**4%**	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			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**399,397**	394,025	409,479	**402,381**	398,258
North America – Oil Sands Mining and Upgrading (1)	**408,120**	332,272	387,407	**370,547**	366,606
International – Exploration and Production					
North Sea	**10,925**	11,270	11,968	**11,531**	12,616
Offshore Africa	**12,496**	12,057	11,746	**12,104**	12,273
Total International	**23,421**	23,327	23,714	**23,635**	24,889
Total Crude oil and NGLs	**830,938**	749,624	820,600	**796,563**	789,753
Natural gas (MMcf/d)					
North America	**2,016**	2,077	2,068	**2,047**	2,024
International					
North Sea	**1**	2	1	**1**	2
Offshore Africa	**9**	9	10	**10**	10
Total International	**10**	11	11	**11**	12
Total Natural gas	**2,026**	2,088	2,079	**2,058**	2,036
Total Barrels of oil equivalent (BOE/d)	**1,168,599**	1,097,693	1,167,139	**1,139,622**	1,129,014

(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, bitumen (thermal oil), SCO, and natural gas.

Crude oil and NGLs production before royalties for the nine months ended September 30, 2024 averaged 977,265 bbl/d, an increase of 3% from 948,587 bbl/d for the nine months ended September 30, 2023. Crude oil and NGLs production before royalties for the third quarter of 2024 averaged 1,021,572 bbl/d, comparable with 1,035,153 bbl/d for the third quarter of 2023, and an increase of 9% from 934,066 bbl/d for the second quarter of 2024. The increase in crude oil and NGLs production for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 primarily reflected strong performance and utilization in the Oil Sands Mining and Upgrading segment and higher thermal oil production due to pad additions in the North America Exploration and Production segment. The increase in crude oil and NGLs production for the third quarter of 2024 from the second quarter of 2024 reflected strong production at Horizon following the completion of the planned turnaround including all tie-ins and commissioning of the reliability enhancement project in the second quarter of 2024, partially offset by the planned turnaround at the non-operated Scotford Upgrader ("Scotford") which commenced late in the third quarter of 2024.

Annual crude oil and NGLs production for 2024 is targeted to average between 977,000 bbl/d and 1,008,000 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 nine months ended September 30, 2024 averaged 2,102 MMcf/d, comparable with 2,125 MMcf/d for the nine months ended September 30, 2023. Natural gas production before royalties for the third quarter of 2024 averaged 2,049 MMcf/d, a decrease of 5% from 2,151 MMcf/d for the third quarter of 2023 and a decrease of 3% from 2,110 MMcf/d for the second quarter of 2024. The decrease in natural gas production for the third quarter of 2024 from the comparable periods reflected previously announced deferrals of budgeted natural gas well onstream timing in response to natural gas pricing, together with natural field declines. The decrease in natural gas production for the third quarter of 2024 from the second quarter of 2024 also reflected the impact of heat and wildfire conditions in the third quarter of 2024.

Annual natural gas production for 2024 is targeted to average between 2,120 MMcf/d and 2,230 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 nine months ended September 30, 2024 averaged 501,674 bbl/d, an increase of 3% from 487,512 bbl/d for the nine months ended September 30, 2023. North America crude oil and NGLs production before royalties for the third quarter of 2024 of 499,772 bbl/d decreased 4% from 519,581 bbl/d for the third quarter of 2023 and was comparable with 499,636 bbl/d for the second quarter of 2024. The increase in North America crude oil and NGLs production for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 reflected higher thermal oil production due to pad additions, partially offset by natural field declines. The decrease in North America crude oil and NGLs production for the third quarter of 2024 from the third quarter of 2023 reflected the cyclical nature of Primrose and natural field declines, partially offset by thermal pad additions at Jackfish and Kirby.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 271,551 bbl/d for the third quarter of 2024, a decrease of 5% from 287,085 bbl/d for the third quarter of 2023, and comparable with 268,044 bbl/d for the second quarter of 2024. The decrease in thermal in situ production in the third quarter of 2024 from the third quarter of 2023 primarily reflected the cyclical nature of Primrose and natural field declines, partially offset by thermal pad additions at Jackfish and Kirby.

Pelican Lake heavy crude oil production before royalties for the third quarter of 2024 averaged 45,101 bbl/d, a decrease of 4% from 46,897 bbl/d for the third quarter of 2023 and comparable with 44,839 bbl/d for the second quarter of 2024, reflecting Pelican Lake's long life low decline production, partially offset by drilling completed in the first half of 2024.

North America natural gas production before royalties for the nine months ended September 30, 2024 averaged 2,091 MMcf/d, comparable with 2,113 MMcf/d for the nine months ended September 30, 2023. Natural gas production before royalties averaged 2,039 MMcf/d for the third quarter of 2024, a decrease of 5% from 2,139 MMcf/d for the third quarter of 2023 and a decrease of 3% from 2,099 MMcf/d for the second quarter of 2024. The decrease in natural gas production for the third quarter of 2024 from the comparable periods reflected previously announced deferrals of budgeted natural gas well onstream timing in response to natural gas pricing, together with natural field declines. The decrease in natural gas production for the third quarter of 2024 from the second quarter of 2024 also reflected the impact of heat and wildfire conditions in the third quarter of 2024.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the nine months ended September 30, 2024 averaged 451,298 bbl/d, an increase of 4% from 434,895 bbl/d for the nine months ended September 30, 2023. SCO production before royalties for the third quarter of 2024 averaged 497,656 bbl/d, comparable with 490,853 bbl/d for the third quarter of 2023, and an increase of 21% from 410,518 bbl/d for the second quarter of 2024. The increase in SCO production for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 reflected strong performance and utilization at both Horizon and AOSP. The increase in SCO production for the third quarter of 2024 from the second quarter of 2024 primarily reflected the completion of the planned turnaround at Horizon including final tie-ins and commissioning of the reliability enhancement project in the second quarter of 2024, partially offset by the planned turnaround at Scotford, which commenced late in the third quarter of 2024.

International – Exploration and Production

International crude oil and NGLs production before royalties for the nine months ended September 30, 2024 averaged 24,293 bbl/d, a decrease of 7% from 26,180 bbl/d for the nine months ended September 30, 2023. International crude oil and NGLs production before royalties for the third quarter of 2024 averaged 24,144 bbl/d, comparable with 24,719 bbl/d for the third quarter of 2023 and 23,912 bbl/d for the second quarter of 2024. The decrease in International crude oil and NGLs production for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 reflected natural field declines.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when control of the product passes to the customer and delivery has taken place. Revenue has not been recognized in the International segments on crude oil production held in various storage facilities or floating production storage and offloading vessels ("FPSOs"), as follows:

(bbl)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023
International	**655,729**	1,145,760	1,167,250

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs ($/bbl) [1]					
Realized price [2]	**$ 79.15**	$ 86.64	$ 87.83	**$ 78.67**	$ 73.45
Transportation [2]	**5.26**	5.98	4.07	**5.30**	4.37
Realized price, net of transportation [2]	**73.89**	80.66	83.76	**73.37**	69.08
Royalties [3]	**15.05**	17.45	17.32	**14.88**	12.98
Production expense [4]	**14.65**	14.54	14.40	**15.28**	16.51
Netback [2]	**$ 44.19**	$ 48.67	$ 52.04	**$ 43.21**	$ 39.59
Natural gas ($/Mcf) [1]					
Realized price [5]	**$ 1.25**	$ 1.59	$ 2.81	**$ 1.80**	$ 3.20
Transportation [6]	**0.63**	0.63	0.56	**0.62**	0.56
Realized price, net of transportation	**0.62**	0.96	2.25	**1.18**	2.64
Royalties [3]	**0.02**	0.02	0.09	**0.05**	0.15
Production expense [4]	**1.26**	1.21	1.25	**1.26**	1.36
Netback [7]	**$ (0.66)**	$ (0.27)	$ 0.91	**$ (0.13)**	$ 1.13
Barrels of oil equivalent ($/BOE) [1]					
Realized price [2]	**$ 50.36**	$ 55.84	$ 59.40	**$ 51.29**	$ 51.31
Transportation [2]	**4.67**	5.09	3.78	**4.70**	3.97
Realized price, net of transportation [2]	**45.69**	50.75	55.62	**46.59**	47.34
Royalties [3]	**9.05**	10.53	10.61	**8.99**	8.03
Production expense [4]	**11.81**	11.64	11.64	**12.16**	13.10
Netback [2]	**$ 24.83**	$ 28.58	$ 33.37	**$ 25.44**	$ 26.21

(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 royalties divided by respective sales volumes.
(4) Calculated as production expense divided by respective sales volumes.
(5) Calculated as natural gas sales divided by natural gas sales volumes.
(6) Calculated as natural gas transportation expense 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			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs ($/bbl) (1)					
North America (2)	**$ 77.29**	$ 85.49	$ 86.77	**$ 77.06**	$ 71.90
International average (3)	**$ 109.41**	$ 115.27	$ 113.59	**$ 112.14**	$ 105.20
North Sea (3)	**$ 112.54**	$ 115.02	$ 108.22	**$ 113.90**	$ 106.91
Offshore Africa (3)	**$ 108.04**	$ 115.67	$ 118.09	**$ 110.45**	$ 105.55
Crude oil and NGLs average (2)	**$ 79.15**	$ 86.64	$ 87.83	**$ 78.67**	$ 73.45
Natural gas ($/Mcf) (1) (3)					
North America	**$ 1.19**	$ 1.53	$ 2.76	**$ 1.75**	$ 3.15
International average	**$ 12.67**	$ 11.87	$ 12.21	**$ 12.22**	$ 13.04
North Sea	**$ 11.28**	$ 9.79	$ 9.99	**$ 10.79**	$ 10.70
Offshore Africa	**$ 12.87**	$ 12.24	$ 12.44	**$ 12.43**	$ 13.44
Natural gas average	**$ 1.25**	$ 1.59	$ 2.81	**$ 1.80**	$ 3.20
Average ($/BOE) (1) (2)	**$ 50.36**	$ 55.84	$ 59.40	**$ 51.29**	$ 51.31

(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 7% to average $77.06 per bbl for the nine months ended September 30, 2024 from $71.90 per bbl for the nine months ended September 30, 2023. North America realized crude oil and NGLs prices averaged $77.29 per bbl for the third quarter of 2024, a decrease of 11% from $86.77 per bbl for the third quarter of 2023, and a decrease of 10% from $85.49 per bbl for the second quarter of 2024. The increase in North America realized crude oil and NGLs prices for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 primarily reflected the narrowing of the WCS Heavy Differential due to the start-up of the TMX pipeline in the second quarter of 2024, combined with stronger US Gulf Coast heavy oil pricing. The decrease in North America realized crude oil and NGLs prices for the third quarter of 2024 from the comparable periods reflected lower WTI benchmark pricing. The decrease for the third quarter of 2024 from the third quarter of 2023 also reflected the widening of the WCS Heavy Differential. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2024 contributed approximately 199,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 44% to average $1.75 per Mcf for the nine months ended September 30, 2024 from $3.15 per Mcf for the nine months ended September 30, 2023. North America realized natural gas prices decreased 57% to average $1.19 per Mcf for the third quarter of 2024 from $2.76 per Mcf for the third quarter of 2023 and decreased 22% from $1.53 per Mcf for the second quarter of 2024. The decrease in North America realized natural gas prices for the three and nine months ended September 30, 2024 from the comparable periods primarily reflected lower AECO benchmark pricing together with volatility in export pricing.

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

(Quarterly average)	Three Months Ended Sep 30 2024	Jun 30 2024	Sep 30 2023
Wellhead Price [1]			
Light and medium crude oil and NGLs ($/bbl)	**$ 67.58**	$ 74.90	$ 72.07
Pelican Lake heavy crude oil ($/bbl)	**$ 84.02**	$ 92.42	$ 93.19
Primary heavy crude oil ($/bbl)	**$ 83.56**	$ 91.27	$ 93.80
Bitumen (thermal oil) ($/bbl)	**$ 78.26**	$ 86.84	$ 89.50
Natural gas ($/Mcf)	**$ 1.19**	$ 1.53	$ 2.76

(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 7% to average $112.14 per bbl for the nine months ended September 30, 2024 from $105.20 per bbl for the nine months ended September 30, 2023. International realized crude oil and NGLs prices decreased 4% to average $109.41 per bbl for the third quarter of 2024 from $113.59 per bbl for the third quarter of 2023 and decreased 5% from $115.27 per bbl for the second quarter of 2024. 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, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil and NGLs prices for the three and nine months ended September 30, 2024 from the comparable periods primarily reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 15.72**	$ 18.06	$ 17.79	**$ 15.46**	$ 13.31
International average	**$ 4.02**	$ 2.11	$ 5.67	**$ 2.96**	$ 6.07
North Sea	**$ 0.33**	$ 0.24	$ 0.42	**$ 0.27**	$ 0.38
Offshore Africa	**$ 5.65**	$ 5.14	$ 8.90	**$ 5.56**	$ 9.87
Crude oil and NGLs average	**$ 15.05**	$ 17.45	$ 17.32	**$ 14.88**	$ 12.98
Natural gas ($/Mcf) [1]					
North America	**$ 0.01**	$ 0.02	$ 0.09	**$ 0.04**	$ 0.14
Offshore Africa	**$ 0.59**	$ 0.56	$ 0.59	**$ 0.57**	$ 0.64
Natural gas average	**$ 0.02**	$ 0.02	$ 0.09	**$ 0.05**	$ 0.15
Average ($/BOE) [1]	**$ 9.05**	$ 10.53	$ 10.61	**$ 8.99**	$ 8.03

(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 nine months ended September 30, 2024 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 20% of product sales for the nine months ended September 30, 2024 compared with 19% of product sales for the nine months ended September 30, 2023. Crude oil and NGLs royalty rates averaged approximately 20% of product sales for the third quarter of 2024 compared with 21% for the third quarter of 2023 and 21% for the second quarter of 2024. The fluctuations in royalty rates for the three and nine months ended September 30, 2024 from the comparable periods was primarily due to prevailing benchmark pricing and fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 2% of product sales for the nine months ended September 30, 2024 compared with 5% of product sales for the nine months ended September 30, 2023. Natural gas royalty rates averaged approximately 1% of product sales for the third quarter of 2024 compared with 3% for the third quarter of 2023 and 1% for the second quarter of 2024. The decrease in royalty rates for the three and nine months ended September 30, 2024 from the comparable periods was primarily due to lower benchmark prices.

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 nine months ended September 30, 2024 compared with 9% of product sales for the nine months ended September 30, 2023. Royalty rates as a percentage of product sales averaged approximately 5% for the third quarter of 2024 compared with 7% of product sales for the third quarter of 2023 and 4% for the second quarter of 2024. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2024	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 12.36**	$ 12.44	$ 13.21	**$ 13.17**	$ 15.16
International average	**$ 52.04**	$ 66.83	$ 44.16	**$ 59.04**	$ 44.94
North Sea	**$ 120.92**	$ 96.07	$ 83.44	**$ 98.49**	$ 81.92
Offshore Africa	**$ 21.67**	$ 19.28	$ 20.04	**$ 20.94**	$ 20.23
Crude oil and NGLs average	**$ 14.65**	$ 14.54	$ 14.40	**$ 15.28**	$ 16.51
Natural gas ($/Mcf) [1]					
North America	**$ 1.23**	$ 1.19	$ 1.22	**$ 1.23**	$ 1.33
International average	**$ 6.24**	$ 6.51	$ 7.40	**$ 6.13**	$ 6.72
North Sea	**$ 9.61**	$ 7.72	$ 9.19	**$ 8.60**	$ 9.95
Offshore Africa	**$ 5.75**	$ 6.30	$ 7.21	**$ 5.77**	$ 6.17
Natural gas average	**$ 1.26**	$ 1.21	$ 1.25	**$ 1.26**	$ 1.36
Average ($/BOE) [1]	**$ 11.81**	$ 11.64	$ 11.64	**$ 12.16**	$ 13.10

(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 nine months ended September 30, 2024 averaged $13.17 per bbl, a decrease of 13% from $15.16 per bbl for the nine months ended September 30, 2023. North America crude oil and NGLs production expense for the third quarter of 2024 of $12.36 per bbl decreased 6% from $13.21 per bbl for the third quarter of 2023 and was comparable with $12.44 per bbl for the second quarter of 2024. The decrease in crude oil and NGLs production expense per bbl for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 reflected lower energy costs combined with higher production volumes. The decrease in crude oil and NGLs production expense per bbl for the third quarter of 2024 from the third quarter of 2023 primarily reflected lower energy costs, partially offset by lower production volumes in the third quarter of 2024.

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

North America natural gas production expense for the nine months ended September 30, 2024 averaged $1.23 per Mcf, a decrease of 8% from $1.33 per Mcf for the nine months ended September 30, 2023. North America natural gas production expense for the third quarter of 2024 of $1.23 per Mcf was comparable with $1.22 per Mcf for the third quarter of 2023 and increased 3% from $1.19 per Mcf for the second quarter of 2024. The decrease in natural gas production expense per Mcf for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 reflected lower energy costs. The increase in natural gas production expense for the third quarter of 2024 from the second quarter of 2024 primarily reflected lower production volumes in the third quarter of 2024.

International

International crude oil and NGLs production expense for the nine months ended September 30, 2024 averaged $59.04 per bbl, an increase of 31% from $44.94 per bbl for the nine months ended September 30, 2023. International crude oil and NGLs production expense for the third quarter of 2024 of $52.04 per bbl increased 18% from $44.16 per bbl for the third quarter of 2023 and decreased 22% from $66.83 per bbl for the second quarter of 2024. Fluctuations in crude oil and NGLs production expense for the three and nine months ended September 30, 2024 from the comparable periods reflected the timing of liftings from various fields that have different cost structures and the impact of foreign exchange.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
North America	**$ 924**	$ 956	$ 947	**$ 2,821**	$ 2,708
North Sea	**17**	24	12	**58**	28
Offshore Africa	**96**	108	47	**251**	147
Depletion, depreciation and amortization	**$ 1,037**	$ 1,088	$ 1,006	**$ 3,130**	$ 2,883
Less: Recoverability charge (1)	**—**	62	—	**62**	—
Adjusted depletion, depreciation and amortization (2)	**$ 1,037**	$ 1,026	$ 1,006	**$ 3,068**	$ 2,883
$/BOE (3)	**$ 13.27**	$ 12.77	$ 12.22	**$ 12.89**	$ 12.21

(1) In connection with the Company's notice of withdrawal from Block 11B/12B in South Africa in the second quarter of 2024, the Company derecognized $62 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

(2) This is a non-GAAP financial measure used to calculate depletion, depreciation and amortization, less the impact of charges that are not related to current period normal course depletion, depreciation and amortization expense such as asset recoverability charges that are not related to current period production. It 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 (depletion, depreciation and amortization expense), as an indication of the Company's performance.

(3) This is a non-GAAP ratio calculated as adjusted 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.

Adjusted depletion, depreciation and amortization expense for the nine months ended September 30, 2024 averaged $12.89 per BOE, an increase of 6% from $12.21 per BOE for the nine months ended September 30, 2023. Adjusted depletion, depreciation and amortization expense for the third quarter of 2024 averaged $13.27 per BOE, an increase of 9% from $12.22 per BOE for the third quarter of 2023, and an increase of 4% from $12.77 per BOE for the second quarter of 2024. The increase in adjusted depletion, depreciation and amortization expense per BOE for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 primarily reflected the impact of changes in North America depletion rates due to changes in reserve estimates at December 31, 2023. The increase in adjusted depletion, depreciation and amortization expense per BOE for the three months ended September 30, 2024 from the comparable periods reflected lower sales volumes in North America.

Adjusted depletion, depreciation and amortization expense on an absolute and per BOE basis also reflects the impact of the timing of liftings from each field in the North Sea and Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
North America	**$ 58**	$ 57	$ 59	**$ 173**	$ 176
North Sea	**16**	16	11	**48**	34
Offshore Africa	**2**	2	2	**6**	6
Asset retirement obligation accretion	**$ 76**	$ 75	$ 72	**$ 227**	$ 216
$/BOE [(1)]	**$ 0.97**	$ 0.95	$ 0.87	**$ 0.96**	$ 0.91

(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 nine months ended September 30, 2024 averaged $0.96 per BOE, an increase of 5% from $0.91 per BOE for the nine months ended September 30, 2023. Asset retirement obligation accretion expense for the third quarter of 2024 averaged $0.97 per BOE, an increase of 11% from $0.87 per BOE for the third quarter of 2023, and comparable with $0.95 per BOE for the second quarter of 2024. The increase in asset retirement obligation accretion expense per BOE for the three and nine months ended September 30, 2024 from the comparable periods in 2023 primarily reflected the Company's estimate for future abandonment costs for the Ninian field in the North Sea at December 31, 2023.

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. SCO production averaged 497,656 bbl/d in the third quarter of 2024, reflecting record quarterly SCO production at Horizon resulting from strong production and utilization.

The Company incurred production expense of $935 million for the third quarter of 2024, a decrease of 7% from $1,003 million for the third quarter of 2023, and comparable with $941 million for the second quarter of 2024. The decrease in production expense for the third quarter of 2024 from the third quarter of 2023 primarily reflected lower energy costs. The Company continues to focus on cost control and driving efficiencies across the Oil Sands Mining and Upgrading segment.

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

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Realized SCO sales price [(1)]	**$ 100.93**	$ 108.81	$ 108.55	**$ 99.19**	$ 100.57
Bitumen value for royalty purposes [(2)]	**$ 76.16**	$ 82.08	$ 84.66	**$ 73.93**	$ 66.85
Bitumen royalties [(3)]	**$ 17.71**	$ 20.01	$ 21.90	**$ 17.24**	$ 15.52
Transportation [(1)]	**$ 3.34**	$ 2.81	$ 2.18	**$ 2.62**	$ 1.91

(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.

The realized SCO sales price averaged $99.19 per bbl for the nine months ended September 30, 2024, comparable with $100.57 per bbl for the nine months ended September 30, 2023. The realized SCO sales price averaged $100.93 per bbl for the third quarter of 2024, a decrease of 7% from $108.55 per bbl for the third quarter of 2023, and a decrease of 7% from $108.81 per bbl for the second quarter of 2024. The decrease in realized SCO sales price for the third quarter of 2024 from the comparable periods primarily reflected the decrease in WTI benchmark pricing combined with weaker diesel pricing.

The fluctuations in bitumen royalties per bbl for the three and nine months ended September 30, 2024 from the comparable periods reflected prevailing bitumen pricing for royalty purposes, and the impact of sliding scale royalty rates.

Transportation expense averaged $2.62 per bbl for the nine months ended September 30, 2024, an increase of 37% from $1.91 per bbl for the nine months ended September 30, 2023. Transportation expense averaged $3.34 per bbl for the third quarter of 2024, an increase of 53% from $2.18 per bbl for the third quarter of 2023, and an increase of 19% from $2.81 per bbl for the second quarter of 2024. The increase in transportation expense per bbl for the three and nine months ended September 30, 2024 from the comparable periods primarily reflected higher volumes shipped to the US Gulf Coast and on the TMX pipeline.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Production expense, excluding natural gas costs	**$ 917**	$ 917	$ 962	**$ 2,810**	$ 2,890
Natural gas costs	**18**	24	41	**92**	152
Production expense	**$ 935**	$ 941	$ 1,003	**$ 2,902**	$ 3,042

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Production expense, excluding natural gas costs (1)	**$ 20.27**	$ 25.29	$ 21.22	**$ 22.89**	$ 24.33
Natural gas costs (2)	**0.40**	0.66	0.90	**0.75**	1.28
Production expense (3)	**$ 20.67**	$ 25.95	$ 22.12	**$ 23.64**	$ 25.61
Sales volumes (bbl/d)	**491,635**	398,528	492,926	**448,145**	435,109

(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 nine months ended September 30, 2024 averaged $23.64 per bbl, a decrease of 8% from $25.61 per bbl for the nine months ended September 30, 2023. Production expense for the third quarter of 2024 averaged $20.67 per bbl, a decrease of 7% from $22.12 per bbl for the third quarter of 2023, and a decrease of 20% from $25.95 per bbl for the second quarter of 2024. The decrease in production expense per bbl for the three and nine months ended September 30, 2024 from the comparable periods in 2023 reflected lower energy costs and higher production volumes. The decrease in production expense per bbl for the third quarter of 2024 from the second quarter of 2024 primarily reflected higher production volumes following the planned turnaround at Horizon including final tie-ins and commissioning of the reliability enhancement project in the second quarter of 2024.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Depletion, depreciation and amortization	**$ 556**	$ 557	$ 527	**$ 1,637**	$ 1,457
$/bbl (1)	**$ 12.27**	$ 15.37	$ 11.62	**$ 13.33**	$ 12.27

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

Depletion, depreciation and amortization expense for the nine months ended September 30, 2024 averaged $13.33 per bbl, an increase of 9% from $12.27 per bbl for the nine months ended September 30, 2023. Depletion, depreciation and amortization expense for the third quarter of 2024 of $12.27 per bbl increased 6% from $11.62 per bbl for the third quarter of 2023 and decreased 20% from $15.37 per bbl for the second quarter of 2024. The increase in depletion, depreciation and amortization expense per bbl for the nine months ended September 30, 2024 from the nine months ended September 30, 2023 primarily reflected derecognitions related to the turnaround in the second quarter of 2024 and higher sales volumes at Horizon in 2024. The increase in depletion, depreciation and amortization expense per bbl for the third quarter of 2024 from the third quarter of 2023 primarily reflected the impact of a higher depletable base due to asset additions combined with higher sales volumes at Horizon. The decrease in depletion, depreciation and amortization expense per bbl for the third quarter of 2024 from the second quarter of 2024 primarily reflected the impact of higher sales volumes in the third quarter of 2024.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Sep 30 2024	Jun 30 2024	Sep 30 2023	Nine Months Ended Sep 30 2024	Sep 30 2023
Asset retirement obligation accretion	**$ 21**	$ 22	$ 20	**$ 64**	$ 59
$/bbl [1]	**$ 0.46**	$ 0.58	$ 0.43	**$ 0.51**	$ 0.50

(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 nine months ended September 30, 2024 of $0.51 per bbl was comparable with $0.50 per bbl for the nine months ended September 30, 2023. Asset retirement obligation accretion expense for the third quarter of 2024 of $0.46 per bbl increased 7% from $0.43 per bbl for the third quarter of 2023 and decreased 21% from $0.58 per bbl for the second quarter of 2024. The increase in asset retirement obligation accretion expense per bbl for the third quarter of 2024 from the third quarter of 2023 primarily reflected the net impact of changes in estimates related to cost, timing and discount rates at December 31, 2023, combined with slightly lower sales volumes in the third quarter of 2024. The decrease in asset retirement obligation accretion expense per bbl for the third quarter of 2024 from the second quarter of 2024 reflected the impact of higher sales volumes in the third quarter of 2024.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended Sep 30 2024	Jun 30 2024	Sep 30 2023	Nine Months Ended Sep 30 2024	Sep 30 2023
Product sales					
Midstream activities	**$ 20**	$ 21	$ 20	**$ 61**	$ 56
NWRP, refined product sales and other	**191**	215	237	**620**	690
Segmented revenue	**211**	236	257	**681**	746
Less:					
NWRP, refining toll	**75**	81	66	**230**	221
Midstream activities	**3**	7	8	**15**	22
Production expense	**78**	88	74	**245**	243
NWRP, transportation and feedstock costs	**169**	194	183	**521**	498
Depreciation	**5**	4	4	**13**	12
Segmented loss	**$ (41)**	$ (50)	$ (4)	**$ (98)**	$ (7)

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 50,000 bbl/d bitumen upgrader and refinery that processes approximately 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. 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 refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the third quarter of 2024, production of ultra-low sulphur diesel and other refined products averaged 72,109 BOE/d (18,027 BOE/d to the Company) (three months ended June 30, 2024 – 78,272 BOE/d; 19,568 BOE/d to the Company; three months ended September 30, 2023 – 78,376 BOE/d; 19,594 BOE/d to the Company), reflecting the 25% toll payer commitment.

During the third quarter of 2024, NWRP repaid $500 million of 3.20% series A bonds.

During the second quarter of 2024, NWRP issued $700 million of 4.85% series P bonds due June 1, 2034 and $600 million of 5.08% series Q bonds due June 1, 2054. Additionally, NWRP extended its revolving credit facility originally maturing June 2025 to June 2027, and reduced the capacity from $2,175 million to $1,900 million. NWRP also repaid $440 million on its non-revolving credit facility maturing June 2025, reducing the amount outstanding to $500 million.

As at September 30, 2024, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $510 million (December 31, 2023 – $555 million). For the three months ended September 30, 2024, the Company's recovery of its share of unrecognized equity losses was $6 million (nine months ended September 30, 2024 – recovery of unrecognized equity losses of $45 million; three months ended September 30, 2023 – recovery of unrecognized equity losses of $18 million; nine months ended September 30, 2023 – recovery of unrecognized equity losses of $1 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Administration expense	**$ 126**	$ 124	$ 108	**$ 376**	$ 333
$/BOE (1)	**$ 1.02**	$ 1.06	$ 0.84	**$ 1.04**	$ 0.94
Sales volumes (BOE/d) (2)	**1,342,508**	1,280,416	1,388,033	**1,316,989**	1,300,390

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

(2) Total Company sales volumes.

Administration expense for the nine months ended September 30, 2024 of $1.04 per BOE increased 11% from $0.94 per BOE for the nine months ended September 30, 2023. Administration expense for the third quarter of 2024 of $1.02 per BOE increased 21% from $0.84 per BOE for the third quarter of 2023 and decreased 4% from $1.06 per BOE for the second quarter of 2024. The increase in administration expense per BOE for the three and nine months ended September 30, 2024 from the comparable periods in 2023 primarily reflected higher personnel and corporate costs, partially offset by higher overhead recoveries. The decrease in administration expense per BOE for the third quarter of 2024 from the second quarter of 2024 reflected higher sales volumes, partially offset by higher personnel costs.

SHARE-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Share-based compensation (recovery) expense	**$ (46)**	$ (13)	$ 298	**$ 235**	$ 434

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, and by individual employee performance and the extent to which certain other performance measures are met.

The Company recognized $235 million of share-based compensation expense for the nine months ended September 30, 2024, primarily as a result of 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, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price.

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)	Three Months Ended **Sep 30 2024**	Jun 30 2024	Sep 30 2023	Nine Months Ended **Sep 30 2024**	Sep 30 2023
Interest and other financing expense	**$ 154**	$ 158	$ 187	**$ 450**	$ 519
Less: Interest (income) and other expense (1)	**(5)**	(7)	4	**(34)**	(2)
Interest expense on long-term debt and lease liabilities (1)	**$ 159**	$ 165	$ 183	**$ 484**	$ 521
Average current and long-term debt (2)	**$ 11,130**	$ 11,568	$ 13,393	**$ 11,431**	$ 12,882
Average lease liabilities (2)	**1,511**	1,525	1,490	**1,526**	1,505
Average long-term debt and lease liabilities (2)	**$ 12,641**	$ 13,093	$ 14,883	**$ 12,957**	$ 14,387
Average effective interest rate (3) (4)	**4.9%**	4.9%	4.8%	**4.9%**	4.8%
Interest and other financing expense per $/BOE (5)	**$ 1.24**	$ 1.35	$ 1.46	**$ 1.25**	$ 1.46
Sales volumes (BOE/d) (6)	**1,342,508**	1,280,416	1,388,033	**1,316,989**	1,300,390

(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 per BOE for the nine months ended September 30, 2024 decreased 14% to $1.25 per BOE from $1.46 per BOE for the nine months ended September 30, 2023. Interest and other financing expense per BOE for the third quarter of 2024 decreased 15% to $1.24 per BOE from $1.46 per BOE for the third quarter of 2023 and decreased 8% from $1.35 per BOE for the second quarter of 2024. The decrease in interest and other financing expense per BOE for the three and nine months ended September 30, 2024 from the comparable periods in 2023 primarily reflected lower average debt levels in the third quarter of 2024. The decrease in interest and other financing expense per BOE for the third quarter of 2024 from the second quarter of 2024 primarily reflected lower average debt levels and higher sales volumes in the third quarter of 2024.

The Company's average effective interest rate for the three and nine months ended September 30, 2024 of 4.9% increased from the comparable periods in 2023, primarily reflecting higher prevailing interest rates on floating rate long-term debt held during 2024.

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.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Foreign currency contracts	**$ (27)**	$ 12	$ 30	**$ 11**	$ (2)
Natural gas financial instruments [1] [2]	**6**	6	(1)	**11**	5
Net realized (gain) loss	**(21)**	18	29	**22**	3
Foreign currency contracts	**5**	3	2	**17**	7
Natural gas financial instruments [1] [2]	**(5)**	(3)	1	**(4)**	12
Net unrealized loss	**—**	—	3	**13**	19
Net (gain) loss	**$ (21)**	$ 18	$ 32	**$ 35**	$ 22

(1) Certain commodity financial instruments were assumed in the acquisition of Painted Pony Energy Ltd. in the fourth quarter of 2020.

(2) In the fourth quarter of 2023, the Company entered into 50,000 MMBtu/d of US$1.82 AECO fixed price financial contracts for the period of January to December 2024.

During the nine months ended September 30, 2024 net realized risk management losses were related to the settlement of foreign currency contracts and natural gas financial instruments. The Company recorded a net unrealized loss of $13 million ($13 million after tax of $nil) on its risk management activities for the nine months ended September 30, 2024 (nine months ended September 30, 2023 – unrealized loss of $19 million ($16 million after tax of $3 million)).

Further details related to outstanding derivative financial instruments as at September 30, 2024 are disclosed in note 16 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Net realized loss (gain)	**$ 30**	$ 118	$ (48)	**$ 129**	$ (30)
Net unrealized (gain) loss	**(148)**	(15)	250	**106**	16
Net (gain) loss [1]	**$ (118)**	$ 103	$ 202	**$ 235**	$ (14)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange loss for the nine months ended September 30, 2024 was primarily related to the repayment of the US dollar debt in the second quarter of 2024. The net unrealized foreign exchange loss for the nine months ended September 30, 2024 was primarily related to the translation of outstanding US dollar debt, partially offset by the repayment of the US dollar debt. The US/Canadian dollar exchange rate as at September 30, 2024 was US$0.7405 (June 30, 2024 – US$0.7306, September 30, 2023 – US$0.7387).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended Sep 30 2024	Jun 30 2024	Sep 30 2023	Nine Months Ended Sep 30 2024	Sep 30 2023
North America [1]	**$ 433**	$ 548	$ 587	**$ 1,393**	$ 1,366
North Sea	**(12)**	(13)	(11)	**(30)**	(9)
Offshore Africa	**12**	5	23	**22**	53
Current PRT – North Sea	**(47)**	(6)	—	**(67)**	(45)
Other taxes	**3**	(14)	3	**(8)**	9
Current income tax	**389**	520	602	**1,310**	1,374
Deferred corporate income tax	**120**	14	195	**148**	203
Deferred PRT – North Sea	**34**	7	6	**47**	24
Deferred income tax	**154**	21	201	**195**	227
Income tax	**$ 543**	$ 541	$ 803	**$ 1,505**	$ 1,601
Earnings before taxes	**$ 2,809**	$ 2,256	$ 3,147	**$ 6,473**	$ 7,207
Effective tax rate on net earnings [2]	**19%**	24%	26%	**23%**	22%

($ millions, except effective tax rates)	Three Months Ended Sep 30 2024	Jun 30 2024	Sep 30 2023	Nine Months Ended Sep 30 2024	Sep 30 2023
Income tax	**$ 543**	$ 541	$ 803	**$ 1,505**	$ 1,601
Tax effect on non-operating items [3]	**1**	17	4	**32**	14
Current PRT – North Sea	**47**	6	—	**67**	45
Deferred PRT – North Sea	**(34)**	(7)	(6)	**(47)**	(24)
Other taxes	**(3)**	14	(3)	**8**	(9)
Effective tax on adjusted net earnings	**$ 554**	$ 571	$ 798	**$ 1,565**	$ 1,627
Adjusted net earnings from operations [4]	**$ 2,071**	$ 1,892	$ 2,850	**$ 5,437**	$ 5,987
Adjusted net earnings from operations, before taxes	**$ 2,625**	$ 2,463	$ 3,648	**$ 7,002**	$ 7,614
Effective tax rate on adjusted net earnings from operations [5] [6]	**21%**	23%	22%	**22%**	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, unrealized risk management, and a recoverability charge related to the notice to withdraw from Block 11B/12B in South Africa.

(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 nine months ended September 30, 2024 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 nine months ended September 30, 2024 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the decommissioning activities at the Company's platforms 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			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	**$ 8**	$ (4)	$ (2)	**$ 73**	$ 35
Net property dispositions	**—**	—	(1)	**—**	(3)
Total Exploration and Evaluation Assets	**8**	(4)	(3)	**73**	32
Property, Plant and Equipment					
Net property acquisitions	**88**	4	8	**89**	25
Well drilling, completion and equipping	**469**	478	352	**1,360**	1,305
Production and related facilities	**387**	353	301	**995**	1,016
Other	**14**	13	18	**39**	48
Total Property, Plant and Equipment	**958**	848	679	**2,483**	2,394
Total Exploration and Production	**966**	844	676	**2,556**	2,426
Oil Sands Mining and Upgrading					
Project costs	**55**	123	112	**240**	270
Sustaining capital	**302**	526	286	**1,109**	1,027
Turnaround costs	**12**	114	18	**137**	172
Net property acquisitions (dispositions)	**—**	—	6	**(2)**	6
Other	**3**	1	2	**5**	4
Total Oil Sands Mining and Upgrading	**372**	764	424	**1,489**	1,479
Midstream and Refining	**3**	3	1	**10**	6
Head Office	**8**	10	7	**28**	23
Net capital expenditures	**$ 1,349**	$ 1,621	$ 1,108	**$ 4,083**	$ 3,934
Abandonment expenditures	**$ 204**	$ 129	$ 123	**$ 495**	$ 360
By Segment					
North America	**$ 896**	$ 804	$ 629	**$ 2,401**	$ 2,291
North Sea	**29**	3	14	**36**	22
Offshore Africa	**41**	37	33	**119**	113
Oil Sands Mining and Upgrading	**372**	764	424	**1,489**	1,479
Midstream and Refining	**3**	3	1	**10**	6
Head Office	**8**	10	7	**28**	23
Net capital expenditures	**$ 1,349**	$ 1,621	$ 1,108	**$ 4,083**	$ 3,934

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

(2) Non-GAAP Financial Measure. The composition of this measure has been updated for all periods presented. 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 $4,083 million for the nine months ended September 30, 2024, compared with $3,934 million for the nine months ended September 30, 2023. Net capital expenditures were $1,349 million for the third quarter of 2024, compared with $1,108 million for the third quarter of 2023 and $1,621 million for the second quarter of 2024.

In addition, the Company reported abandonment expenditures of $495 million for the nine months ended September 30, 2024, compared with $360 million for the nine months ended September 30, 2023. Abandonment expenditures were $204 million for the third quarter of 2024, compared with $123 million for the third quarter of 2023 and $129 million for the second quarter of 2024. The increase in abandonment expenditures in the third quarter of 2024 from the comparable periods primarily relates to abandonment activities in the North Sea.

2024 Capital Budget

On December 14, 2023, the Company announced its 2024 capital budget targeted at approximately $5,420 million, and targeting to provide near-term production growth in 2024 and mid- and long-term production and capacity growth in 2025 and beyond. Production for 2024 is targeted between 1,330,000 BOE/d and 1,380,000 BOE/d. In addition, the Company targets $635 million in abandonment expenditures for 2024.

The 2024 capital budget constitutes forward-looking statements and is based on net capital expenditures (Non-GAAP Financial Measure) excluding net acquisition costs. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Agreement to Acquire Assets from Chevron Canada Limited

On October 7, 2024, the Company announced that it had entered into an agreement to acquire, subject to regulatory approvals, from Chevron, its 20% interest in AOSP and its 70% operated working interest in light crude oil and liquids rich assets in the Duvernay play in Alberta for total cash consideration of US$6.5 billion, before closing adjustments. The agreement also includes the acquisition of additional working interests in a number of other non-producing oil sands leases. The acquisitions are targeted to close in the fourth quarter of 2024.

The information in this MD&A relates to the Company's operations for the three and nine months ended September 30, 2024 and does not reflect closing of the acquisitions.

Drilling Activity(1) (2)

	Three Months Ended			Nine Months Ended	
(number of net wells)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Net successful crude oil wells (3)	**83**	63	44	**207**	179
Net successful natural gas wells	**24**	24	10	**64**	52
Dry wells	**1**	1	—	**2**	2
Total	**108**	88	54	**273**	233
Success rate	**99%**	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 third quarter of 2024, the Company drilled 24 net natural gas wells, 48 net primary heavy crude oil wells, 25 net bitumen (thermal oil) wells and 11 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2024**	Jun 30 2024	Dec 31 2023	Sep 30 2023
Adjusted working capital (1)	**$ 365**	$ (194)	$ 712	$ 866
Long-term debt, net (2)	**$ 9,308**	$ 9,234	$ 9,922	$ 11,519
Shareholders' equity	**$ 39,897**	$ 39,469	$ 39,832	$ 39,634
Debt to book capitalization (2)	**18.9%**	19.0%	19.9%	22.5%
After-tax return on average capital employed (3)	**15.9%**	16.1%	17.2%	15.0%

(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 September 30, 2024, 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, 2023. 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 when 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:
  - 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.
  - During the second quarter of 2024, the Company repaid $320 million of 3.55% medium-term notes.
  - In July 2023, 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 August 2025. 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.
  - During the second quarter of 2024, the Company repaid US$500 million of 3.80% US dollar debt securities.
  - In July 2023, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2025. 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.

- Subsequent to September 30, 2024, the Company extended its revolving syndicated credit facility originally maturing June 2025 to June 2028.
- Subsequent to September 30, 2024 and in connection with the agreement to acquire assets from Chevron, the Company obtained a fully committed $4,000 million non-revolving term loan facility.

As at September 30, 2024, the Company had undrawn revolving bank credit facilities of $5,450 million. Including cash and cash equivalents, the Company had approximately $6,171 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At September 30, 2024, the Company had no commercial paper drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

Long-term debt, net was $9,308 million as at September 30, 2024 (December 31, 2023 – $9,922 million), resulting in a debt to book capitalization ratio of 18.9% (December 31, 2023 – 19.9%); this ratio was below the 25% to 45% internal range utilized by management. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. The debt to book capitalization ratio is targeted to be within the internally targeted range upon close of the agreement to acquire assets from Chevron. 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 September 30, 2024 are discussed in note 9 to the financial statements.

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 September 30, 2024, the Company was in compliance with this covenant.

During the second quarter of 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for $25.65 per common share with net proceeds, after fees and expenses, of $575 million.

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 put options is in addition to the above parameters.

As at September 30, 2024, 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)]	$ 1,618	$ —	$ 2,355	$ 6,108
Other long-term liabilities [(2)]	$ 267	$ 196	$ 395	$ 638
Interest and other financing expense [(3)]	$ 540	$ 493	$ 1,246	$ 3,116

(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, $259 million; one to less than two years, $196 million; two to less than five years, $395 million; and thereafter, $638 million.

(3) 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 September 30, 2024.

Share Capital[1]

As at September 30, 2024, there were 2,113,135,000 common shares outstanding (December 31, 2023 – 2,144,815,000 common shares) and 52,315,000 stock options outstanding (December 31, 2023 – 52,410,000 stock options). As at October 29, 2024, the Company had 2,109,858,000 common shares outstanding and 51,637,000 stock options outstanding.

On October 7, 2024, the Board of Directors approved a 7% increase in the quarterly dividend to $0.5625 per common share, beginning with the dividend payable on January 3, 2025. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $0.525 per common share.

On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $0.50 per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.45 per common share.

On March 8, 2024, 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, up to 180,462,858 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2024 and ending March 12, 2025.

For the nine months ended September 30, 2024, the Company purchased 43,650,000 common shares at a weighted average price of $48.33 per common share for a total cost, including tax, of $2,140 million. Retained earnings were reduced by $1,915 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2024, up to and including October 29, 2024, the Company purchased 3,780,000 common shares at a weighted average price of $48.92 per common share for a total cost, including tax, of $188 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 September 30, 2024:

($ millions)	Remaining 2024	2025	2026	2027	2028	Thereafter
Product transportation, purchases and processing (1) (2)	$ 480	$ 2,079	$ 1,995	$ 1,907	$ 1,805	$ 20,064
North West Redwater Partnership service toll (3)	$ 37	$ 144	$ 125	$ 109	$ 111	$ 4,500
Offshore vessels and equipment	$ 11	$ 35	$ —	$ —	$ —	$ —
Field equipment and power	$ 18	$ 25	$ 23	$ 23	$ 23	$ 193
Other	$ 34	$ 111	$ 111	$ 21	$ 22	$ 268

(1) The Company's commitment for the 20-year product transportation agreement 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 third quarter of 2024, the Company increased its commitment on the TMX pipeline by an incremental 75,000 bbl/d over a 20-year period.

(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 $2,416 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.

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the Advisory section of this MD&A and in note 1 of the financial statements.

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 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, 2023.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the nine months ended September 30, 2024 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 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.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Net earnings	**$ 2,266**	$ 1,715	$ 2,344	**$ 4,968**	$ 5,606
Share-based compensation, net of tax (1)	**(48)**	(15)	295	**218**	423
Unrealized risk management loss, net of tax (2)	**1**	—	2	**13**	16
Unrealized foreign exchange (gain) loss, net of tax (3)	**(148)**	(15)	250	**106**	16
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**—**	135	—	**135**	—
Loss (gain) from investment, net of tax (5)	**—**	25	(41)	**(50)**	(74)
Recoverability charge, net of tax (6)	**—**	47	—	**47**	—
Non-operating items, net of tax	**(195)**	177	506	**469**	381
Adjusted net earnings from operations	**$ 2,071**	$ 1,892	$ 2,850	**$ 5,437**	$ 5,987

(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 September 30, 2024 was a recovery of $46 million (three months ended June 30, 2024 – $13 million recovery, three months ended September 30, 2023 – $298 million expense; nine months ended September 30, 2024 – $235 million expense; nine months ended September 30, 2023 – $434 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 crude oil, natural gas and foreign exchange. Pre-tax unrealized risk management loss (gain) for the three months ended September 30, 2024 was $nil (three months ended June 30, 2024 – $nil, three months ended September 30, 2023 – $3 million loss; nine months ended September 30, 2024 – $13 million loss; nine months ended September 30, 2023 – $19 million loss).

(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) During the second quarter of 2024, the Company repaid US$500 million of 3.80% debt securities due April 2024, resulting in a pre- and after-tax foreign exchange loss of $135 million.

(5) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with gains and losses recognized in net earnings. During the second quarter of 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for $25.65 per common share with net proceeds, after fees and expenses, of $575 million. There is a $nil net tax impact on the sale as the Company has sufficient capital losses to offset the capital gain on the sale.

(6) In connection with the Company’s notice of withdrawal from Block 11B/12B in South Africa in the second quarter of 2024, the Company derecognized $62 million ($47 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

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.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Cash flows from operating activities	**$ 3,002**	$ 4,084	$ 3,498	**$ 9,954**	$ 7,538
Net change in non-cash working capital	**680**	(515)	1,088	**180**	2,979
Abandonment expenditures	**204**	129	123	**495**	360
Movements in other long-term assets (1)	**35**	(84)	(25)	**44**	(22)
Adjusted funds flow	**$ 3,921**	$ 3,614	$ 4,684	**$ 10,673**	$ 10,855

(1) Includes the unamortized cost of the share bonus program, the accrued interest on the deferred PRT recovery, 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 15 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.

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 non-GAAP financial measures: realized price and transportation, reconciled below to their respective line item in note 18 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 exclude the impact of blending and feedstock costs and other by-product sales. 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.

	Three Months Ended			Nine Months Ended	
($ millions, except bbl/d and $/bbl)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs (bbl/d)					
North America	**479,889**	509,674	516,038	**494,674**	487,917
International					
North Sea	**9,020**	12,682	7,839	**11,713**	9,305
Offshore Africa	**20,450**	7,800	12,769	**12,129**	13,931
Total International	**29,470**	20,482	20,608	**23,842**	23,236
Total sales volumes	**509,359**	530,156	536,646	**518,516**	511,153
Crude oil and NGLs sales [(1)]	**$ 4,653**	$ 5,484	$ 5,351	**$ 14,642**	$ 13,597
Less: Blending and feedstock costs [(2)]	**946**	1,303	1,014	**3,466**	3,346
Realized crude oil and NGLs sales	**$ 3,707**	$ 4,181	$ 4,337	**$ 11,176**	$ 10,251
Realized price ($/bbl)	**$ 79.15**	$ 86.64	$ 87.83	**$ 78.67**	$ 73.45

(1) Crude oil and NGLs sales in note 18 to the financial statements.

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

	Three Months Ended			Nine Months Ended	
($ millions, except BOE/d and $/BOE)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Barrels of oil equivalent (BOE/d)					
North America	**819,606**	859,536	872,555	**843,074**	840,032
International					
North Sea	**9,246**	12,959	8,022	**11,961**	9,598
Offshore Africa	**22,021**	9,393	14,530	**13,809**	15,651
Total International	**31,267**	22,352	22,552	**25,770**	25,249
Total sales volumes	**850,873**	881,888	895,107	**868,844**	865,281
Barrels of oil equivalent sales [(1)]	**$ 4,889**	$ 5,788	$ 5,908	**$ 15,681**	$ 15,455
Less: Blending and feedstock costs [(2)]	**946**	1,303	1,014	**3,466**	3,346
Less: Sulphur expense (income)	**2**	3	1	**6**	(12)
Realized barrels of oil equivalent sales	**$ 3,941**	$ 4,482	$ 4,893	**$ 12,209**	$ 12,121
Realized price ($/BOE)	**$ 50.36**	$ 55.84	$ 59.40	**$ 51.29**	$ 51.31

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 18 to the financial statements.

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

Transportation – Exploration and Production

Transportation ($/BOE, $/bbl and $/Mcf) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by the respective sales volumes. The Company calculates transportation to demonstrate its cost to deliver products to the market excluding the impact of blending costs. A reconciliation for Exploration and Production transportation and the calculations for transportation on a per unit basis are presented below.

	Three Months Ended			Nine Months Ended	
($ millions, except $ per unit amounts)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Transportation, blending and feedstock [(1)]	**$ 1,312**	$ 1,712	$ 1,326	**$ 4,584**	$ 4,285
Less: Blending and feedstock costs	**946**	1,303	1,014	**3,466**	3,346
Transportation	**$ 366**	$ 409	$ 312	**$ 1,118**	$ 939
Transportation ($/BOE)	**$ 4.67**	$ 5.09	$ 3.78	**$ 4.70**	$ 3.97
Amounts attributed to crude oil and NGLs	**$ 246**	$ 289	$ 200	**$ 752**	$ 610
Transportation ($/bbl)	**$ 5.26**	$ 5.98	$ 4.07	**$ 5.30**	$ 4.37
Amounts attributed to natural gas	**$ 120**	$ 120	$ 112	**$ 366**	$ 329
Transportation ($/Mcf)	**$ 0.63**	$ 0.63	$ 0.56	**$ 0.62**	$ 0.56

(1) Transportation, blending and feedstock in note 18 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 exclude the impact of blending costs. 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.

	Three Months Ended			Nine Months Ended	
($ millions, except $/bbl and royalty rates)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Crude oil and NGLs sales [(1)]	**$ 4,357**	$ 5,269	$ 5,135	**$ 13,910**	$ 12,924
Less: Blending and feedstock costs [(2)]	**946**	1,303	1,014	**3,466**	3,346
Realized crude oil and NGLs sales	**$ 3,411**	$ 3,966	$ 4,121	**$ 10,444**	$ 9,578
Realized crude oil and NGLs prices ($/bbl)	**$ 77.29**	$ 85.49	$ 86.77	**$ 77.06**	$ 71.90
Crude oil and NGLs royalties [(3)]	**$ 694**	$ 838	$ 845	**$ 2,095**	$ 1,773
Crude oil and NGLs royalty rates	**20%**	21%	21%	**20%**	19%

(1) Crude oil and NGLs sales in note 18 to the financial statements.

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled above in the "Transportation – Exploration and Production" section.

(3) Item is a component of royalties in note 18 to the financial statements.

Realized Product Prices and Transportation – Oil Sands Mining and Upgrading

Realized SCO sales price ($/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) excluding the impact of blending and feedstock costs, divided by SCO sales volumes. 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.

Transportation ($/bbl) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by SCO sales volumes. The Company calculates transportation to demonstrate its cost to deliver product to the market excluding the impact of blending and feedstock costs.

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

	Three Months Ended			Nine Months Ended	
($ millions, except for bbl/d and $/bbl)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
SCO sales volumes (bbl/d)	**491,635**	398,528	492,926	**448,145**	435,109
Crude oil and NGLs sales [1]	**$ 5,208**	$ 4,525	$ 5,591	**$ 13,901**	$ 13,619
Less: Blending and feedstock costs	**643**	579	670	**1,721**	1,674
Realized SCO sales	**$ 4,565**	$ 3,946	$ 4,921	**$ 12,180**	$ 11,945
Realized SCO sales price ($/bbl)	**$ 100.93**	$ 108.81	$ 108.55	**$ 99.19**	$ 100.57
Transportation, blending and feedstock [2]	**$ 794**	$ 682	$ 768	**$ 2,044**	$ 1,900
Less: Blending and feedstock costs	**643**	579	670	**1,721**	1,674
Transportation	**$ 151**	$ 103	$ 98	**$ 323**	$ 226
Transportation ($/bbl)	**$ 3.34**	$ 2.81	$ 2.18	**$ 2.62**	$ 1.91

(1) Crude oil and NGLs sales in note 18 to the financial statements.

(2) Transportation, blending and feedstock in note 18 to the financial statements.

Change in Composition of Non-GAAP Financial Measure

During the fourth quarter of 2023, the Company revised the composition of its Net Capital Expenditures non-GAAP financial measure to exclude expenditures related to the Company's abandonment program. The revision was made during Management's assessment of its annual capital budgeting process, and will provide users a better representation of the Company's performance and the composition of its capital budget. The composition of this measure has been updated for all periods presented.

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 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.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2024**	Jun 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Cash flows used in investing activities	**$ 1,274**	$ 1,015	$ 1,199	**$ 3,681**	$ 3,912
Net proceeds from investment	**—**	575	—	**575**	—
Net change in non-cash working capital	**75**	31	(91)	**(173)**	22
Net capital expenditures	**1,349**	1,621	1,108	**4,083**	3,934
Abandonment expenditures	**204**	129	123	**495**	360
Capital and abandonment expenditures	**$ 1,553**	$ 1,750	$ 1,231	**$ 4,578**	$ 4,294

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)	**Sep 30 2024**	Jun 30 2024	Dec 31 2023	Sep 30 2023
Undrawn bank credit facilities	**$ 5,450**	$ 5,450	$ 5,450	$ 5,450
Cash and cash equivalents	**721**	915	877	125
Investments [(1)]	**—**	—	525	565
Liquidity	**$ 6,171**	$ 6,365	$ 6,852	$ 6,140

(1) During the second quarter of 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for $25.65 per common share with net proceeds, after fees and expenses, of $575 million.

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 14 to the financial statements. A reconciliation of long-term debt, net is presented below.

($ millions)	**Sep 30 2024**	Jun 30 2024	Dec 31 2023	Sep 30 2023
Long-term debt	**$ 10,029**	$ 10,149	$ 10,799	$ 11,644
Less: cash and cash equivalents	**721**	915	877	125
Long-term debt, net	**$ 9,308**	$ 9,234	$ 9,922	$ 11,519

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 14 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)	**Sep 30 2024**	Jun 30 2024	Dec 31 2023	Sep 30 2023
Interest adjusted after-tax return:				
Net earnings, 12 months trailing	**$ 7,595**	$ 7,673	$ 8,233	$ 7,126
Interest and other financing expense, net of tax, 12 months trailing [(1)]	**435**	461	490	459
Interest adjusted after-tax return	**$ 8,030**	$ 8,134	$ 8,723	$ 7,585
12 months average current portion long-term debt [(2)]	**$ 1,366**	$ 1,506	$ 1,259	$ 1,337
12 months average long-term debt [(2)]	**9,366**	9,651	10,354	10,706
12 months average common shareholders' equity [(2)]	**39,668**	39,418	38,974	38,635
12 months average capital employed	**$ 50,400**	$ 50,575	$ 50,587	$ 50,678
After-tax return on average capital employed	**15.9%**	16.1%	17.2%	15.0%

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

(2) 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	**Sep 30 2024**	Dec 31 2023
ASSETS			
Current assets			
Cash and cash equivalents		**$ 721**	$ 877
Accounts receivable		**3,100**	3,189
Inventory		**2,531**	2,034
Prepaids and other		**356**	471
Investments	7	**—**	525
Current portion of other long-term assets	8	**67**	71
		6,775	7,167
Exploration and evaluation assets	4	**2,182**	2,208
Property, plant and equipment	5	**64,137**	64,581
Lease assets	6	**1,404**	1,458
Other long-term assets	8	**583**	541
		$ 75,081	$ 75,955
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,152**	$ 1,418
Accrued liabilities		**3,735**	3,534
Current income taxes payable		**103**	—
Current portion of long-term debt	9	**1,618**	980
Current portion of other long-term liabilities	10	**1,420**	1,503
		8,028	7,435
Long-term debt	9	**8,411**	9,819
Other long-term liabilities	10	**8,385**	8,686
Deferred income taxes		**10,360**	10,183
		35,184	36,123
SHAREHOLDERS' EQUITY			
Share capital	12	**11,050**	10,712
Retained earnings		**28,647**	28,948
Accumulated other comprehensive income	13	**200**	172
		39,897	39,832
		$ 75,081	$ 75,955

Commitments and contingencies (note 17)

Approved by the Board of Directors on October 30, 2024.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Sep 30 2024**	Three Months Ended Sep 30 2023	Nine Months Ended **Sep 30 2024**	Nine Months Ended Sep 30 2023
Product sales	18	**$ 10,401**	$ 11,762	**$ 30,445**	$ 30,156
Less: royalties		**(1,508)**	(1,867)	**(4,257)**	(3,741)
Revenue		**8,893**	9,895	**26,188**	26,415
Expenses					
Production		**1,949**	2,049	**6,085**	6,424
Transportation, blending and feedstock		**2,345**	2,289	**7,284**	6,953
Depletion, depreciation and amortization	4,5,6	**1,598**	1,537	**4,780**	4,352
Administration		**126**	108	**376**	333
Share-based compensation	10	**(46)**	298	**235**	434
Asset retirement obligation accretion	10	**97**	92	**291**	275
Interest and other financing expense		**154**	187	**450**	519
Risk management (gain) loss	16	**(21)**	32	**35**	22
Foreign exchange (gain) loss		**(118)**	202	**235**	(14)
Gain from investments	7	**—**	(46)	**(56)**	(90)
		6,084	6,748	**19,715**	19,208
Earnings before taxes		**2,809**	3,147	**6,473**	7,207
Current income tax expense	11	**389**	602	**1,310**	1,374
Deferred income tax expense	11	**154**	201	**195**	227
Net earnings		**$ 2,266**	$ 2,344	**$ 4,968**	$ 5,606
Net earnings per common share [1]					
Basic	15	**$ 1.07**	$ 1.08	**$ 2.33**	$ 2.56
Diluted	15	**$ 1.06**	$ 1.06	**$ 2.31**	$ 2.53

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended **Sep 30 2024**	Three Months Ended Sep 30 2023	Nine Months Ended **Sep 30 2024**	Nine Months Ended Sep 30 2023
Net earnings	**$ 2,266**	$ 2,344	**$ 4,968**	$ 5,606
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 (2023 – $nil) – three months ended; $nil (2023 – $nil) – nine months ended	**1**	1	**1**	2
Reclassification to net earnings, net of taxes of $nil (2023 – $nil) – three months ended; $nil (2023 – $nil) – nine months ended	**(2)**	(3)	**(3)**	(5)
	(1)	(2)	**(2)**	(3)
Foreign currency translation adjustment				
Translation of net investment	**(21)**	33	**30**	2
Other comprehensive (loss) income, net of taxes	**(22)**	31	**28**	(1)
Comprehensive income	**$ 2,244**	$ 2,375	**$ 4,996**	$ 5,605

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended **Sep 30 2024**	Sep 30 2023
Share capital	12		
Balance – beginning of period		**$ 10,712**	$ 10,294
Issued upon exercise of stock options		**248**	274
Previously recognized liability on stock options exercised for common shares		**315**	302
Purchase of common shares under Normal Course Issuer Bid		**(225)**	(216)
Balance – end of period		**11,050**	10,654
Retained earnings			
Balance – beginning of period		**28,948**	27,672
Net earnings		**4,968**	5,606
Dividends on common shares	12	**(3,354)**	(2,953)
Purchase of common shares under Normal Course Issuer Bid, including tax	12	**(1,915)**	(1,553)
Balance – end of period		**28,647**	28,772
Accumulated other comprehensive income	13		
Balance – beginning of period		**172**	209
Other comprehensive income (loss), net of taxes		**28**	(1)
Balance – end of period		**200**	208
Shareholders' equity		**$ 39,897**	$ 39,634

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2024**	Three Months Ended Sep 30 2023	Nine Months Ended **Sep 30 2024**	Nine Months Ended Sep 30 2023
Operating activities					
Net earnings		**$ 2,266**	$ 2,344	**$ 4,968**	$ 5,606
Non-cash items					
Depletion, depreciation and amortization	4,5,6	**1,598**	1,537	**4,780**	4,352
Share-based compensation		**(46)**	298	**235**	434
Asset retirement obligation accretion		**97**	92	**291**	275
Unrealized risk management loss		**—**	3	**13**	19
Unrealized foreign exchange (gain) loss		**(148)**	250	**106**	16
Gain from investments	7	**—**	(41)	**(50)**	(74)
Deferred income tax expense		**154**	201	**195**	227
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**135**	—
Abandonment expenditures	10	**(204)**	(123)	**(495)**	(360)
Other		**(35)**	25	**(44)**	22
Net change in non-cash working capital		**(680)**	(1,088)	**(180)**	(2,979)
Cash flows from operating activities		**3,002**	3,498	**9,954**	7,538
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	9	**—**	(731)	**—**	202
Repayment of medium-term notes	9	**—**	—	**(320)**	(11)
Repayment of US dollar debt securities	9	**—**	—	**(688)**	—
Payment of lease liabilities	6	**(84)**	(71)	**(241)**	(206)
Issue of common shares on exercise of stock options	12	**21**	84	**248**	274
Dividends on common shares		**(1,118)**	(984)	**(3,319)**	(2,911)
Purchase of common shares under Normal Course Issuer Bid	12	**(741)**	(594)	**(2,109)**	(1,769)
Cash flows used in financing activities		**(1,922)**	(2,296)	**(6,429)**	(4,421)
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets	4,18	**(8)**	3	**(73)**	(32)
Net expenditures on property, plant and equipment	5,18	**(1,341)**	(1,111)	**(4,010)**	(3,902)
Net proceeds from investment	7	**—**	—	**575**	—
Net change in non-cash working capital		**75**	(91)	**(173)**	22
Cash flows used in investing activities		**(1,274)**	(1,199)	**(3,681)**	(3,912)
(Decrease) increase in cash and cash equivalents		**(194)**	3	**(156)**	(795)
Cash and cash equivalents – beginning of period		**915**	122	**877**	920
Cash and cash equivalents – end of period		**$ 721**	$ 125	**$ 721**	$ 125
Interest paid on long-term debt, net		**$ 174**	$ 187	**$ 481**	$ 490
Income taxes paid, net		**$ 322**	$ 349	**$ 957**	$ 2,556

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 direct and indirect 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. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34 "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2023, 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, 2023.

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.

Common Share Split and Comparative Figures

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

2. CHANGE IN ACCOUNTING POLICIES

In January 2020, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to clarify that liabilities are classified as either current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period. In October 2022, the IASB issued further amendments to specify that the classification of debt as current or non-current at the reporting date is not affected by covenants to be complied with after the reporting date. The amendments were adopted on January 1, 2024 and had no impact on the Company's interim consolidated financial statements.

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 performance measures 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 assessing the impact of IFRS 18 on the Company's consolidated financial statements.

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 requirements for assessing whether a financial asset meets the solely payments of principal and interest criterion, and adds disclosure requirements for financial instruments with certain contingent features and for equity investments designated at fair value through other comprehensive income. The amendments are effective January 1, 2026, with early adoption permitted. The amendments are required to be adopted retrospectively by adjusting the opening balance of financial assets, financial liabilities and retained earnings at the date of adoption. The Company is assessing the impact of the amendments on the Company's consolidated financial statements.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2023	$ 2,031	$ —	$ 100	$ 77	$ 2,208
Additions, net	**76**	**—**	**(3)**	**—**	**73**
Transfers to property, plant and equipment	**(37)**	**—**	**—**	**—**	**(37)**
Derecognitions and other [(1)]	**—**	**—**	**(62)**	**—**	**(62)**
At September 30, 2024	**$ 2,070**	**$ —**	**$ 35**	**$ 77**	**$ 2,182**

(1) In connection with the Company's notice of withdrawal from Block 11B/12B in South Africa in the second quarter of 2024, the Company derecognized $62 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

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, 2023	$ 83,483	$ 8,606	$ 4,409	$ 49,375	$ 484	$ 566	$ 146,923
Additions	**2,344**	**36**	**122**	**1,489**	**10**	**28**	**4,029**
Transfers from exploration and evaluation assets	**37**	**—**	**—**	**—**	**—**	**—**	**37**
Derecognitions [(1)]	**(452)**	**—**	**—**	**(381)**	**—**	**—**	**(833)**
Foreign exchange adjustments and other	**—**	**196**	**99**	**—**	**—**	**—**	**295**
At September 30, 2024	**$ 85,412**	**$ 8,838**	**$ 4,630**	**$ 50,483**	**$ 494**	**$ 594**	**$ 150,451**
Accumulated depletion and depreciation							
At December 31, 2023	$ 58,840	$ 8,382	$ 3,358	$ 11,105	$ 213	$ 444	$ 82,342
Expense	**2,754**	**41**	**155**	**1,511**	**12**	**19**	**4,492**
Derecognitions [(1)]	**(452)**	**—**	**—**	**(381)**	**—**	**—**	**(833)**
Foreign exchange adjustments and other	**19**	**192**	**81**	**21**	**—**	**—**	**313**
At September 30, 2024	**$ 61,161**	**$ 8,615**	**$ 3,594**	**$ 12,256**	**$ 225**	**$ 463**	**$ 86,314**
Net book value							
At September 30, 2024	**$ 24,251**	**$ 223**	**$ 1,036**	**$ 38,227**	**$ 269**	**$ 131**	**$ 64,137**
At December 31, 2023	$ 24,643	$ 224	$ 1,051	$ 38,270	$ 271	$ 122	$ 64,581

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

On October 7, 2024, the Company announced that it had entered into an agreement to acquire, subject to regulatory approvals, from Chevron Canada Limited ("Chevron"), its 20% interest in AOSP and its 70% operated working interest in light crude oil and liquids rich assets in the Duvernay play in Alberta for total cash consideration of US$6.5 billion, before closing adjustments. The agreement also includes the acquisition of additional working interests in a number of other non-producing oil sands leases. The acquisitions are targeted to close in the fourth quarter of 2024.

6. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2023	$ 840	$ 482	$ 71	$ 65	$ 1,458
Additions	**5**	**71**	**32**	**66**	**174**
Depreciation	**(70)**	**(101)**	**(40)**	**(15)**	**(226)**
Foreign exchange adjustments and other	**—**	**(1)**	**2**	**(3)**	**(2)**
At September 30, 2024	**$ 775**	**$ 451**	**$ 65**	**$ 113**	**$ 1,404**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at September 30, 2024 were as follows:

	Sep 30 2024	Dec 31 2023
Lease liabilities	**$ 1,488**	$ 1,555
Less: current portion	**259**	298
	$ 1,229	$ 1,257

Total cash outflows for leases for the three months ended September 30, 2024, including payments related to short-term leases not reported as lease assets, were $332 million (three months ended September 30, 2023 – $345 million; nine months ended September 30, 2024 – $987 million; nine months ended September 30, 2023 – $1,023 million). Interest expense on leases for the three months ended September 30, 2024 was $18 million (three months ended September 30, 2023 – $16 million; nine months ended September 30, 2024 – $53 million; nine months ended September 30, 2023 – $48 million).

7. INVESTMENTS

During the second quarter of 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. ("PrairieSky") for $25.65 per common share with net proceeds, after fees and expenses, of $575 million. During the nine months ended September 30, 2024, the Company realized a $50 million gain on the investment in PrairieSky and dividend income of $6 million.

8. OTHER LONG-TERM ASSETS

	Sep 30 2024	Dec 31 2023
Long-term prepayments, contracts and other [(1)]	**$ 295**	$ 279
Prepaid cost of service tolls	**161**	179
Long-term inventory	**187**	141
Risk management (note 16)	**7**	13
	650	612
Less: current portion	**67**	71
	$ 583	$ 541

(1) Includes physical product sales contracts, accrued interest on the deferred PRT recovery, and the unamortized portion of the Company's share bonus program.

The Company has a 50% equity investment in NWRP. NWRP operates a 50,000 barrels per day bitumen upgrader and refinery that processes approximately 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. 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 17). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 18).

During the third quarter of 2024, NWRP repaid $500 million of 3.20% series A bonds.

During the second quarter of 2024, NWRP issued $700 million of 4.85% series P bonds due June 1, 2034 and $600 million of 5.08% series Q bonds due June 1, 2054. Additionally, NWRP extended its revolving credit facility originally maturing June 2025 to June 2027, and reduced the capacity from $2,175 million to $1,900 million. NWRP also repaid $440 million on its non-revolving credit facility maturing June 2025, reducing the amount outstanding to $500 million.

The carrying value of the Company's interest in NWRP is $nil, and as at September 30, 2024, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $510 million (December 31, 2023 – $555 million). For the three months ended September 30, 2024, the Company's recovery of its share of unrecognized equity losses was $6 million (nine months ended September 30, 2024 – recovery of unrecognized equity losses of $45 million; three months ended September 30, 2023 – recovery of unrecognized equity losses of $18 million; nine months ended September 30, 2023 – recovery of unrecognized equity losses of $1 million).

9. LONG-TERM DEBT

	Sep 30 2024	Dec 31 2023
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 966**	$ 1,286
US dollar denominated debt, unsecured		
US dollar debt securities (September 30, 2024 – US$6,750 million; December 31, 2023 – US$7,250 million)	**9,115**	9,573
Long-term debt before transaction costs and original issue discounts, net	**10,081**	10,859
Less: original issue discounts, net (1)	**10**	11
transaction costs (1) (2)	**42**	49
	10,029	10,799
Less: current portion of long-term debt (1) (2)	**1,618**	980
	$ 8,411	$ 9,819

(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 September 30, 2024, the Company had undrawn revolving bank credit facilities of $5,450 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 February 2025;
- a $2,425 million revolving syndicated credit facility, maturing June 2025; and
- a $2,425 million revolving syndicated credit facility, maturing June 2027.

Subsequent to September 30, 2024, the Company extended its revolving syndicated credit facility originally maturing June 2025 to June 2028.

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's weighted average interest rate on total long-term debt outstanding for the nine months ended September 30, 2024 was 4.9% (September 30, 2023 – 4.7%).

As at September 30, 2024, letters of credit and guarantees aggregating to $729 million were outstanding (December 31, 2023 – $446 million).

In connection with the agreement to acquire assets from Chevron and subsequent to September 30, 2024, the Company obtained a fully committed $4,000 million non-revolving term loan facility. This facility matures three years from the closing date of the acquisitions. The Company also issued letters of credit of US$650 million that will be cancelled upon close.

Medium-Term Notes

During the second quarter of 2024, the Company repaid $320 million of 3.55% medium-term notes.

In July 2023, 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 August 2025. 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.

US Dollar Debt Securities

During the second quarter of 2024, the Company repaid US$500 million of 3.80% US dollar debt securities.

In July 2023, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2025. 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.

10. OTHER LONG-TERM LIABILITIES

	Sep 30 2024	Dec 31 2023
Asset retirement obligations	**$ 7,543**	$ 7,690
Lease liabilities (note 6)	**1,488**	1,555
Share-based compensation	**621**	780
Transportation and processing contracts	**64**	87
Risk management (note 16)	**8**	4
Other	**81**	73
	9,805	10,189
Less: current portion	**1,420**	1,503
	$ 8,385	$ 8,686

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 5.2% (December 31, 2023 – 5.2%) and inflation rates of up to 2% (December 31, 2023 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Sep 30 2024	Dec 31 2023
Balance – beginning of period	**$ 7,690**	$ 6,908
Liabilities incurred	**21**	25
Liabilities disposed, net	**(2)**	—
Liabilities settled	**(495)**	(509)
Asset retirement obligation accretion	**291**	366
Revision of cost, inflation and timing estimates (1)	**—**	621
Change in discount rates	**—**	314
Foreign exchange adjustments	**38**	(35)
Balance – end of period	**7,543**	7,690
Less: current portion	**673**	634
	$ 6,870	$ 7,056

(1) Includes normal course revisions of cost, inflation and timing estimates, as well as revisions related to cost estimate increases in 2023 on future abandonment of the Ninian field assets in the North Sea.

Share-Based Compensation

The liability for share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. 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, and 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.

	Sep 30 2024	Dec 31 2023
Balance – beginning of period	**$ 780**	$ 832
Share-based compensation expense	**235**	491
Cash payment for stock options surrendered and PSUs vested	**(82)**	(110)
Transferred to common shares	**(315)**	(435)
Other	**3**	2
Balance – end of period	**621**	780
Less: current portion	**458**	538
	$ 163	$ 242

11. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
Expense (recovery)	**Sep 30 2024**	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Current corporate income tax – North America [1]	**$ 433**	$ 587	**$ 1,393**	$ 1,366
Current corporate income tax – North Sea	**(12)**	(11)	**(30)**	(9)
Current corporate income tax – Offshore Africa	**12**	23	**22**	53
Current PRT [2] – North Sea	**(47)**	—	**(67)**	(45)
Other taxes	**3**	3	**(8)**	9
Current income tax	**389**	602	**1,310**	1,374
Deferred corporate income tax	**120**	195	**148**	203
Deferred PRT [2] – North Sea	**34**	6	**47**	24
Deferred income tax	**154**	201	**195**	227
Income tax	**$ 543**	$ 803	**$ 1,505**	$ 1,601

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

(2) Petroleum Revenue Tax.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares[1]	Nine Months Ended Sep 30, 2024 Number of shares (thousands)	Amount
Balance – beginning of period	**2,144,815**	**$ 10,712**
Issued upon exercise of stock options	**11,970**	**248**
Previously recognized liability on stock options exercised for common shares	**—**	**315**
Purchase of common shares under Normal Course Issuer Bid	**(43,650)**	**(225)**
Balance – end of period	**2,113,135**	**$ 11,050**

Dividends[1]

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 October 7, 2024, the Board of Directors approved a 7% increase in the quarterly dividend to $0.5625 per common share, beginning with the dividend payable on January 3, 2025. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $0.525 per common share.

On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $0.50 per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.45 per common share.

Normal Course Issuer Bid[1]

On March 8, 2024, 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, up to 180,462,858 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2024 and ending March 12, 2025.

For the nine months ended September 30, 2024, the Company purchased 43,650,000 common shares at a weighted average price of $48.33 per common share for a total cost, including tax, of $2,140 million. Retained earnings were reduced by $1,915 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2024, up to and including October 29, 2024, the Company purchased 3,780,000 common shares at a weighted average price of $48.92 per common share for a total cost, including tax, of $188 million.

Share-Based Compensation – Stock Options[1]

The following table summarizes information relating to stock options outstanding as at September 30, 2024:

	Nine Months Ended Sep 30, 2024 Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	**52,410**	**$ 26.80**
Granted	**15,392**	**$ 44.71**
Exercised for common shares	**(11,970)**	**$ 20.75**
Surrendered for cash settlement	**(319)**	**$ 22.17**
Forfeited	**(3,198)**	**$ 29.23**
Outstanding – end of period	**52,315**	**$ 33.33**
Exercisable – end of period	**7,347**	**$ 24.49**

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.

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Sep 30 2024	Sep 30 2023
Derivative financial instruments designated as cash flow hedges	**$ 70**	$ 72
Foreign currency translation adjustment	**130**	136
	$ 200	$ 208

14. 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 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. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. As at September 30, 2024, the ratio was below the target range at 18.9%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS 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.

	Sep 30 2024	Dec 31 2023
Long-term debt	**$ 10,029**	$ 10,799
Less: cash and cash equivalents	**721**	877
Long-term debt, net	**$ 9,308**	$ 9,922
Total shareholders' equity	**$ 39,897**	$ 39,832
Debt to book capitalization	**18.9%**	19.9%

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 September 30, 2024, the Company was in compliance with this covenant.

15. NET EARNINGS PER COMMON SHARE(1)

		Three Months Ended		Nine Months Ended	
		Sep 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Weighted average common shares outstanding – basic (thousands of shares)		**2,119,970**	2,180,263	**2,131,767**	2,190,366
Effect of dilutive stock options (thousands of shares)		**13,093**	21,323	**15,417**	21,960
Weighted average common shares outstanding – diluted (thousands of shares)		**2,133,063**	2,201,586	**2,147,184**	2,212,326
Net earnings		**$ 2,266**	$ 2,344	**$ 4,968**	$ 5,606
Net earnings per common share	– basic	**$ 1.07**	$ 1.08	**$ 2.33**	$ 2.56
	– diluted	**$ 1.06**	$ 1.06	**$ 2.31**	$ 2.53

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

16. FINANCIAL INSTRUMENTS

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

The estimated fair values of derivative financial instruments in Level 2 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)	**Sep 30 2024**	Dec 31 2023
Balance – beginning of period	**$ 9**	$ 6
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities [1] [2]	**(10)**	3
Balance – end of period	**(1)**	9
Less: current portion	**(2)**	8
	$ 1	$ 1

(1) Risk management assets and liabilities are disclosed in note 8 and note 10, respectively.

(2) In the fourth quarter of 2023, the Company entered into 50,000 MMBtu/d of US$1.82 AECO fixed price financial contracts for the period of January to December 2024.

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2024	Sep 30 2023	**Sep 30 2024**	Sep 30 2023
Net realized risk management (gain) loss	**$ (21)**	$ 29	**$ 22**	$ 3
Net unrealized risk management loss	**—**	3	**13**	19
	$ (21)	$ 32	**$ 35**	$ 22

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. 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:

	Sep 30, 2024	
	Carrying amount	**Level 1 Fair Value**
Fixed rate long-term debt [1] [2]	**$ 10,029**	**$ 10,251**

(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.

Financial Risk Factors

The Company's financial risks are consistent with those discussed in notes 1, 4 and 19 of the Company's audited consolidated financial statements for the year ended December 31, 2023.

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.

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 September 30, 2024, 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.

As at September 30, 2024, the Company had US$1,514 million of foreign currency forward contracts outstanding (December 31, 2023 – US$1,003 million), with original terms of up to 90 days, all of which were designated as derivatives held for trading.

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 September 30, 2024, 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 September 30, 2024, 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	$ 1,152	$ —	$ —	$ —
Accrued liabilities	$ 3,735	$ —	$ —	$ —
Long-term debt (1)	$ 1,618	$ —	$ 2,355	$ 6,108
Other long-term liabilities (2)	$ 267	$ 196	$ 395	$ 638
Interest and other financing expense (3)	$ 540	$ 493	$ 1,246	$ 3,116

(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, $259 million; one to less than two years, $196 million; two to less than five years, $395 million; and thereafter, $638 million.

(3) 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 September 30, 2024.

17. 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 September 30, 2024:

	Remaining 2024	2025	2026	2027	2028	Thereafter
Product transportation, purchases and processing [1] [2]	$ 480	$ 2,079	$ 1,995	$ 1,907	$ 1,805	$ 20,064
North West Redwater Partnership service toll [3]	$ 37	$ 144	$ 125	$ 109	$ 111	$ 4,500
Offshore vessels and equipment	$ 11	$ 35	$ —	$ —	$ —	$ —
Field equipment and power	$ 18	$ 25	$ 23	$ 23	$ 23	$ 193
Other	$ 34	$ 111	$ 111	$ 21	$ 22	$ 268

(1) The Company's commitment for the 20-year product transportation agreement on the Trans Mountain Expansion ("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 third quarter of 2024, the Company increased its commitment on the TMX pipeline by an incremental 75,000 bbl/d over a 20-year period.

(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 $2,416 million of interest payable over the 40-year tolling period, ending in 2058 (note 8).

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.

18. SEGMENTED INFORMATION

	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
(millions of Canadian dollars, unaudited)	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Segmented product sales																
Crude oil and NGLs	**4,357**	5,135	**13,910**	12,924	**93**	78	**365**	272	**203**	138	**367**	401	**4,653**	5,351	**14,642**	13,597
Natural gas	**224**	543	**1,001**	1,815	**1**	1	**4**	5	**11**	13	**34**	38	**236**	557	**1,039**	1,858
Other income and revenue [1]	**(3)**	1	**(10)**	5	**—**	—	**4**	—	**2**	—	**3**	7	**(1)**	1	**(3)**	12
Total segmented product sales	**4,578**	5,679	**14,901**	14,744	**94**	79	**373**	277	**216**	151	**404**	446	**4,888**	5,909	**15,678**	15,467
Less: royalties	**(696)**	(863)	**(2,120)**	(1,858)	**—**	—	**(1)**	(1)	**(11)**	(11)	**(20)**	(39)	**(707)**	(874)	**(2,141)**	(1,898)
Segmented revenue	**3,882**	4,816	**12,781**	12,886	**94**	79	**372**	276	**205**	140	**384**	407	**4,181**	5,035	**13,537**	13,569
Segmented expenses																
Production	**777**	867	**2,490**	2,787	**101**	61	**319**	213	**46**	30	**86**	94	**924**	958	**2,895**	3,094
Transportation, blending and feedstock	**1,309**	1,324	**4,575**	4,278	**3**	1	**9**	6	**—**	1	**—**	1	**1,312**	1,326	**4,584**	4,285
Depletion, depreciation and amortization	**924**	947	**2,821**	2,708	**17**	12	**58**	28	**96**	47	**251**	147	**1,037**	1,006	**3,130**	2,883
Asset retirement obligation accretion	**58**	59	**173**	176	**16**	11	**48**	34	**2**	2	**6**	6	**76**	72	**227**	216
Risk management loss (commodity derivatives)	**1**	—	**7**	17	**—**	—	**—**	—	**—**	—	**—**	—	**1**	—	**7**	17
Total segmented expenses	**3,069**	3,197	**10,066**	9,966	**137**	85	**434**	281	**144**	80	**343**	248	**3,350**	3,362	**10,843**	10,495
Segmented earnings (loss)	**813**	1,619	**2,715**	2,920	**(43)**	(6)	**(62)**	(5)	**61**	60	**41**	159	**831**	1,673	**2,694**	3,074
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management (gain) loss (other)																
Foreign exchange (gain) loss																
Gain from investments																
Total non-segmented expenses																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2024	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Segmented product sales																
Crude oil and NGLs [2]	**5,208**	5,591	**13,901**	13,619	**20**	20	**61**	56	**62**	(18)	**99**	199	**9,943**	10,944	**28,703**	27,471
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**21**	42	**78**	114	**257**	599	**1,117**	1,972
Other income and revenue [1]	**—**	(25)	**(3)**	2	**191**	237	**620**	690	**11**	6	**11**	9	**201**	219	**625**	713
Total segmented product sales	**5,208**	5,566	**13,898**	13,621	**211**	257	**681**	746	**94**	30	**188**	322	**10,401**	11,762	**30,445**	30,156
Less: royalties	**(801)**	(993)	**(2,116)**	(1,843)	**—**	—	**—**	—	**—**	—	**—**	—	**(1,508)**	(1,867)	**(4,257)**	(3,741)
Segmented revenue	**4,407**	4,573	**11,782**	11,778	**211**	257	**681**	746	**94**	30	**188**	322	**8,893**	9,895	**26,188**	26,415
Segmented expenses																
Production	**935**	1,003	**2,902**	3,042	**78**	74	**245**	243	**12**	14	**43**	45	**1,949**	2,049	**6,085**	6,424
Transportation, blending and feedstock [2]	**794**	768	**2,044**	1,900	**169**	183	**521**	498	**70**	12	**135**	270	**2,345**	2,289	**7,284**	6,953
Depletion, depreciation and amortization	**556**	527	**1,637**	1,457	**5**	4	**13**	12	**—**	—	**—**	—	**1,598**	1,537	**4,780**	4,352
Asset retirement obligation accretion	**21**	20	**64**	59	**—**	—	**—**	—	**—**	—	**—**	—	**97**	92	**291**	275
Risk management loss (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**1**	—	**7**	17
Total segmented expenses	**2,306**	2,318	**6,647**	6,458	**252**	261	**779**	753	**82**	26	**178**	315	**5,990**	5,967	**18,447**	18,021
Segmented earnings (loss)	**2,101**	2,255	**5,135**	5,320	**(41)**	(4)	**(98)**	(7)	**12**	4	**10**	7	**2,903**	3,928	**7,741**	8,394
Non-segmented expenses																
Administration													**126**	108	**376**	333
Share-based compensation													**(46)**	298	**235**	434
Interest and other financing expense													**154**	187	**450**	519
Risk management (gain) loss (other)													**(22)**	32	**28**	5
Foreign exchange (gain) loss													**(118)**	202	**235**	(14)
Gain from investments													**—**	(46)	**(56)**	(90)
Total non-segmented expenses													**94**	781	**1,268**	1,187
Earnings before taxes													**2,809**	3,147	**6,473**	7,207
Current income tax													**389**	602	**1,310**	1,374
Deferred income tax													**154**	201	**195**	227
Net earnings													**2,266**	2,344	**4,968**	5,606

(1) Includes the sale of diesel and other refined products in the Midstream and Refining segment, and other income.

(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]

	Nine Months Ended					
	Sep 30, 2024			Sep 30, 2023		
	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	**$ 76**	**$ (37)**	**$ 39**	$ 31	$ (31)	$ —
Offshore Africa	**(3)**	**(62)**	**(65)**	1	—	1
	73	**(99)**	**(26)**	32	(31)	1
Property, plant and equipment						
Exploration and Production						
North America	**2,325**	**(396)**	**1,929**	2,260	(392)	1,868
North Sea	**36**	**—**	**36**	22	—	22
Offshore Africa	**122**	**—**	**122**	112	—	112
	2,483	**(396)**	**2,087**	2,394	(392)	2,002
Oil Sands Mining and Upgrading	**1,489**	**(381)**	**1,108**	1,479	(386)	1,093
Midstream and Refining	**10**	**—**	**10**	6	—	6
Head Office	**28**	**—**	**28**	23	—	23
	4,010	**(777)**	**3,233**	3,902	(778)	3,124
	$ 4,083	**$ (876)**	**$ 3,207**	$ 3,934	$ (809)	$ 3,125

(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

	Sep 30 2024	Dec 31 2023
Exploration and Production		
North America	**$ 29,650**	$ 30,058
North Sea	**488**	602
Offshore Africa	**1,268**	1,380
Other	**54**	32
Oil Sands Mining and Upgrading	**42,372**	42,865
Midstream and Refining	**1,027**	856
Head Office	**222**	162
	$ 75,081	$ 75,955

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 July 2023. 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 September 30, 2024:	
Interest coverage (times)	
Net earnings [(1)]	17.6x
Adjusted funds flow [(2)]	30.8x

(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

This Page Left Intentionally Blank

This Page Left Intentionally Blank

CORPORATE INFORMATION

Board of Directors

Catherine M. Best, FCA, ICD.D
M. Elizabeth Cannon, Ph.D, O.C.
N. Murray Edwards, O.C.
Christopher L. Fong
Ambassador Gordon D. Giffin
Wilfred A. Gobert
Christine M. Healy
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

Mark A. Stainthorpe
Chief Financial Officer

Jay E. Froc
Chief Operating Officer, Oil Sands

Robin S. Zabek
Chief Operating Officer, Exploration and Production

Ron K. Laing
Chief Commercial and Corporate Development Officer

Troy J.P. Andersen
Senior Vice-President, Canadian Conventional Field Operations

Calvin J. Bast
Senior Vice-President, Production

Victor C. Darel
Senior Vice-President, Finance and Principal Accounting Officer

Dwayne F. Giggs
Senior Vice-President, Exploration

Dean W. Halewich
Senior Vice-President, Safety, Risk Management and Innovation

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

2100, 855 - 2 Street S.W. Calgary, Alberta, T2P4J8

www.cnrl.com