CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2023 SECOND QUARTER RESULTS

Commenting on the Company's second quarter 2023 results, Tim McKay, President, stated "Canadian Natural's Q2/23 results demonstrated the advantages of our diverse and balanced asset base by delivering adjusted funds flow of approximately $2.7 billion. As well, we delivered average daily production volumes of approximately 1,194 MBOE/d in the quarter, which was impacted by wildfires in Western Canada, the continued unplanned third-party pipeline outage and planned Company turnarounds during the quarter. Wildfires in Western Canada did not cause any significant property damage to our assets and we would like to acknowledge our field personnel and their families as well as the first responders and emergency response agencies for their efforts in the affected communities over the last few months.

As a result of strong execution on our thermal growth plan, Q3/23 average thermal production is now targeted to be approximately 280,000 bbl/d, which represents growth of approximately 30,000 bbl/d from Q4/22 levels. Thermal production targets to capture strong realizations, as Western Canadian Select ("WCS") pricing has improved significantly year-to-date which, as of today, is forecasted to continue for the remainder of 2023.

Additionally, following the completion of planned turnarounds at our world class Oil Sands Mining and Upgrading assets, synthetic crude oil ("SCO") production was strong, with July 2023 volumes averaging approximately 513,000 bbl/d, capturing SCO pricing which continues to be priced at a premium to WTI.

Environmental, Social and Governance ("ESG") remains a priority for us as evidenced in our 2022 Stewardship Report to Stakeholders which was released today. This report highlights several of our ESG achievements, including top tier safety performance and the shared value achieved by working together across our operations with 167 Indigenous businesses through which approximately $684 million in contracts were awarded in 2022. Additionally, Canadian Natural is an investment leader in research and development ("R&D"). In 2022, we increased our investment in R&D by 30% over 2021 levels with over $587 million invested in technology development and deployment focusing on reductions in our environmental footprint, including reductions in greenhouse gas ("GHG") emissions and productivity improvements. The Company’s strong track record of R&D investment will continue in 2023 and beyond and will be targeted to grow with our participation in the Pathways Alliance. Working together with the federal government of Canada and the Alberta government, the Pathways Alliance is a transformative industry collaboration with an actionable plan that includes the foundational Carbon Capture and Storage ("CCS") project, a significant opportunity to achieve meaningful GHG emissions reductions in support of industry, Alberta and Canada's climate goals. Canadian Natural continues to work together with governments on the importance of balancing environmental and economic objectives along with being able to support Canada’s allies by providing affordable, reliable, responsibly produced energy."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "Canadian Natural delivered solid results in a heavy planned turnaround quarter, as profitability and value from our diverse asset base generated adjusted net earnings of approximately $1.3 billion and adjusted funds flow of approximately $2.7 billion. Our effective and flexible capital allocation to our four pillars: returns to shareholders, balance sheet strength, resource value growth, and opportunistic acquisitions continues to deliver robust financial results.

Year-to-date up to and including August 2, 2023, we have returned approximately $4.3 billion to shareholders through dividends and share repurchases. Our commitment to increasing shareholder returns is evident in our sustainable and growing quarterly dividend which was increased for the 23rd consecutive year in March 2023. As planned maintenance activities were completed in Q2/23, we are targeting strong production volumes and free cash flow for the second half of 2023 as we move towards our $10 billion net debt level and our commitment to return 100% of free cash flow to shareholders. When you combine our leading financial results with our top tier reserves and asset base, this provides us with unique competitive advantages in terms of capital efficiency, flexibility and sustainability, all of which drive material free cash flow generation and strong returns on capital.

This quarter marked the sixth anniversary of the acquisition of 70% of the Athabasca Oil Sands Project ("AOSP"). As part of the acquisition we issued approximately 97.6 million shares, resulting in shares outstanding at May 31, 2017 of approximately 1,215.0 million shares. Shareholder returns through share repurchases since the acquisition closed have been significant, resulting in a reduction of approximately 122.7 million shares over that period to approximately 1,092.3 million shares outstanding as of June 30, 2023, fewer shares outstanding than before acquiring AOSP. Additionally, since the closing, total corporate production has grown by roughly 50% or 442 MBOE/d from approximately 877 MBOE/d in Q1/17 to approximately 1,319 MBOE/d in Q1/23. This demonstrates our focus on safe, reliable production and our culture of continuous improvement."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2023	Mar 31 2023	Jun 30 2022	Six Months Ended Jun 30 2023	Jun 30 2022
Net earnings	**$ 1,463**	$ 1,799	$ 3,502	**$ 3,262**	$ 6,603
Per common share – basic	**$ 1.34**	$ 1.63	$ 3.04	**$ 2.97**	$ 5.70
– diluted	**$ 1.32**	$ 1.62	$ 3.00	**$ 2.94**	$ 5.63
Adjusted net earnings from operations (1)	**$ 1,256**	$ 1,881	$ 3,800	**$ 3,137**	$ 7,176
Per common share – basic (2)	**$ 1.15**	$ 1.71	$ 3.30	**$ 2.86**	$ 6.20
– diluted (2)	**$ 1.14**	$ 1.69	$ 3.26	**$ 2.83**	$ 6.12
Cash flows from operating activities	**$ 2,745**	$ 1,295	$ 5,896	**$ 4,040**	$ 8,749
Adjusted funds flow (1)	**$ 2,742**	$ 3,429	$ 5,432	**$ 6,171**	$ 10,407
Per common share – basic (2)	**$ 2.50**	$ 3.12	$ 4.72	**$ 5.62**	$ 8.99
– diluted (2)	**$ 2.48**	$ 3.08	$ 4.66	**$ 5.57**	$ 8.87
Cash flows used in investing activities	**$ 1,560**	$ 1,153	$ 1,345	**$ 2,713**	$ 2,596
Net capital expenditures, excluding net acquisition costs and strategic growth capital (3)	**$ 1,385**	$ 1,117	$ 1,266	**$ 2,502**	$ 2,110
Net capital expenditures (1)	**$ 1,669**	$ 1,394	$ 1,450	**$ 3,063**	$ 2,905
Daily production, before royalties					
Natural gas (MMcf/d)	**2,085**	2,139	2,105	**2,112**	2,056
Crude oil and NGLs (bbl/d)	**846,909**	962,908	860,338	**904,588**	902,837
Equivalent production (BOE/d) (4)	**1,194,326**	1,319,391	1,211,147	**1,256,513**	1,245,473

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2023 dated August 2, 2023.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2023 dated August 2, 2023.

(3) Net capital expenditures, excluding net acquisition costs and strategic growth capital, is defined as base capital expenditures.

(4) 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 Q2/23, the Company generated strong financial results, including:
  - Net earnings of approximately $1.5 billion and adjusted net earnings from operations of approximately $1.3 billion.
  - Cash flows from operating activities of approximately $2.7 billion.
  - Adjusted funds flow of approximately $2.7 billion.
  - Free cash flow(1) of approximately $0.4 billion(2) after total dividend payments of approximately $1.0 billion and base capital expenditures(3) of approximately $1.4 billion.
- This quarter marked the sixth anniversary of the acquisition of 70% of the Athabasca Oil Sands Project ("AOSP"). As part of the acquisition the Company issued approximately 97.6 million shares, resulting in shares outstanding at May 31, 2017 of approximately 1,215.0 million shares. Shareholder returns through share repurchases since the acquisition closed have been significant, resulting in a reduction of approximately 122.7 million shares over that period to approximately 1,092.3 million shares outstanding as of June 30, 2023, fewer shares outstanding than before acquiring AOSP.
  - Additionally, since the closing, total corporate production has grown by approximately 50% or 442,484 BOE/d from 876,907 BOE/d in Q1/17 to 1,319,391 BOE/d in Q1/23.

- Returns to shareholders in Q2/23 were strong, totaling approximately $1.5 billion, comprised of approximately $1.0 billion of dividends and approximately $0.5 billion of share repurchases.
  - In Q2/23, the Company repurchased approximately 6.4 million common shares for cancellation at a weighted average price of $76.57 per share for a total of approximately $0.5 billion.
  - Canadian Natural increased its sustainable and growing quarterly dividend in March 2023 to $0.90 per common share, marking 2023 as the 23rd consecutive year of dividend increases and demonstrating the confidence that the Board of Directors has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline asset base.
- Year-to-date, up to and including August 2, 2023, the Company has returned approximately $4.3 billion to shareholders through approximately $2.9 billion in dividends and $1.4 billion through the repurchase and cancellation of approximately 17.6 million common shares.
- Subsequent to quarter end, the Company declared a quarterly dividend of $0.90 per share, payable on October 5, 2023 to shareholders of record on September 15, 2023.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with net debt(1) of approximately $12.0 billion and significant liquidity(1) of approximately $5.6 billion at the end of Q2/23.
  - In June 2023, the Company extended its $2.425 billion revolving credit facility by three years, now maturing June 2027 and subsequent to quarter end the Company filed Canadian and US base shelf prospectuses, providing the Company with additional liquidity options.
- The Company's free cash flow allocation policy provides that when net debt is between $10 billion and $15 billion, 50% of free cash flow will be allocated to share repurchases and 50% of free cash flow will be allocated to the balance sheet, less strategic growth / acquisition opportunities. Free cash flow for the purpose of the policy is defined as adjusted funds flow less dividends, less base capital. When net debt reaches $10 billion, returns to shareholders increases to 100% of free cash flow with the free cash flow definition modified to adjusted funds flow less dividends and less total capital expenditures for the year. This is a reflection of the Board of Director's confidence in the sustainability and resilience of the Company to support accelerating incremental shareholder returns to 100% of free cash flow.
- In Q2/23, the Company continued to focus on safe, effective and efficient operations, with quarterly average production volumes of 1,194,326 BOE/d, comparable to Q2/22 levels.
  - Natural gas production averaged 2,085 MMcf/d in Q2/23, compared to Q2/22 levels of 2,105 MMcf/d.
  - Liquids production averaged 846,909 bbl/d in Q2/23, compared to Q2/22 levels of 860,338 bbl/d.
  - Quarterly production in Q2/23 was negatively impacted by wildfires and the previously mentioned third-party pipeline outage which began in Q1/23 and has now been resolved, resulting in a Q2/23 average production impact of approximately 24,400 BOE/d (99 MMcf/d and 7,900 bbl/d).
    - At present, wildfires in Western Canada continue to have a minor impact on production volumes as the Company continues to actively monitor the situation.
  - Following the completion of planned turnarounds at Horizon and the non-operated Scotford Upgrader, the Company achieved strong monthly average production in July 2023 of approximately 513,000 bbl/d of SCO.
- The Company's strategic growth plan targets to increase production from our long life no decline oil sands mining and our low decline thermal in situ assets with the following projects:
  - At Horizon, the reliability enhancement project is targeting to add approximately 14,000 bbl/d of additional SCO production capacity in 2025 as a result of shifting the maintenance schedule from once per year to once every two years, reducing downtime for maintenance activities and increasing overall reliability at Horizon.
    - During the planned turnaround at Horizon and as part of the reliability enhancement project, the Company completed tie-ins of two furnaces. In August 2023, both furnaces are targeted to be operational, increasing SCO production capacity by approximately 5,000 bbl/d, which is included in the Company's 2023 production guidance.
    - Based on the forward strip as of July 24, 2023, these high margin SCO barrels will capture strong pricing with an average premium to WTI pricing of approximately US$3.00/bbl in Q3/23 and Q4/23, generating significant free cash flow for the Company.

- Thermal in situ production is targeted to increase to an average of approximately 280,000 bbl/d in Q3/23, as a result of strong execution enabling the Company to optimize the production schedule on the new Primrose CSS pads, combined with the Kirby SAGD pads coming on stream earlier and ramping up ahead of plan. This represents production growth of approximately 30,000 bbl/d from Q4/22 levels, utilizing existing facility capacity.
  - Based on the forward strip as of July 24, 2023, the tighter average WCS differential of approximately US$15.00/bbl in Q3/23 and Q4/23 is an improvement compared to Q1/23 when WCS differentials averaged approximately US$25.00/bbl. Thermal in situ and heavy crude oil production is well positioned to capture strong pricing, generating significant free cash flow.

▪ The 2023 capital budget in Oil Sands Mining and Upgrading and North America E&P has been increased by a combined $200 million compared to the original budget. In particular, Oil Sands Mining and Upgrading 2023 capital has increased by approximately $130 million largely reflecting increased scope and third-party service costs relating to sustaining activities to ensure safe and effective operations. The remaining approximately $70 million relates to North America E&P and thermal operations, as a result of increased non-operated and workover activity on our properties as well as inflationary pressures. The result is an increase to the Company's 2023 targeted total capital program of roughly 4% to approximately $5.4 billion.

- Despite the wildfires in Western Canada, the third-party pipeline outage in the first half of the year, and the previously announced unplanned outages at Horizon in January 2023, Canadian Natural's 2023 production is still targeted to be within the Company's corporate guidance range of 1,330,000 BOE/d to 1,374,000 BOE/d, but closer to the lower end.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2023, dated August 2, 2023.
(2) Based on sum of rounded numbers.
(3) Item is component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2023 for more details on net capital expenditures.

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 73% of budgeted total liquids production in 2023, 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 our top tier thermal in situ oil sands operations and our 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 land base which enables large, repeatable drilling programs that can be optimized over time. Additionally, by owning and operating most of the related infrastructure, Canadian Natural is able to control major components of the Company's operating costs and minimize production commitments. Low capital exposure projects can be quickly stopped or started 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	Six Months Ended June 30			
	2023		2022	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [1]	**141**	**135**	142	139
Natural gas	**50**	**42**	65	43
Dry	**2**	**2**	1	1
Subtotal	**193**	**179**	208	183
Stratigraphic test / service wells	**470**	**409**	463	395
Total	**663**	**588**	671	578
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- The Company drilled a total of 179 net crude oil and natural gas producer wells in the first half of 2023, comparable to levels in the first half of 2022.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs production (bbl/d)	**226,202**	234,465	227,540	**230,310**	225,052
Net wells targeting crude oil	**29**	60	39	**89**	83
Net successful wells drilled	**29**	58	38	**87**	82
Success rate	**100%**	97%	97%	**98%**	99%

- North America E&P liquids production, excluding thermal in situ, averaged 226,202 bbl/d in Q2/23, comparable to Q2/22 levels, primarily reflecting increased activity and strong drilling results on the Company's primary heavy crude oil assets, offset by natural field declines.

- Primary heavy crude oil production averaged 76,498 bbl/d in Q2/23, a 15% increase from Q2/22 levels, reflecting increased activity and strong drilling results in the Bonnyville/Lloydminster and Clearwater fairways. The Company drilled 24 net primary heavy crude oil wells in Q2/23, of which 18 were multilateral wells and 6 were slant wells.
  - Operating costs(1) in the Company's primary heavy crude oil operations averaged $20.07/bbl (US$14.95/bbl) in Q2/23, a decrease of 12% compared to Q2/22 levels, primarily due to lower natural gas fuel costs.
- Pelican Lake production averaged 47,151 bbl/d in Q2/23, a decrease of 8% from Q2/22 levels, reflecting natural field declines and lower polymer injection rates which were reinstated in February 2023. The field is targeted to return to its historical decline rate of approximately 5% in the second half of 2023.
  - Operating costs at Pelican Lake averaged $8.55/bbl (US$6.37/bbl) in Q2/23, a 7% increase from Q2/22 levels of $7.99/bbl, reflecting higher service and power costs as well as lower production volumes.
- North America light crude oil and NGLs production averaged 102,553 bbl/d in Q2/23, a 7% decrease from Q2/22 levels, primarily reflecting the impact from wildfires and a third-party pipeline outage.
  - Operating costs on the Company's North America light crude oil and NGLs production averaged $18.03/bbl (US$13.43/bbl) in Q2/23, a 19% increase from Q2/22 levels, reflecting the impact of lower production volumes due to wildfires and a third-party pipeline outage as well as higher service and power costs.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Bitumen production (bbl/d)	**238,941**	242,884	249,938	**240,902**	255,808
Net wells targeting bitumen	**23**	25	45	**48**	57
Net successful wells drilled	**23**	25	45	**48**	57
Success rate	**100%**	100%	100%	**100%**	100%

▪ The Company's thermal in situ production averaged 238,941 bbl/d in Q2/23, a decrease of 4% from Q2/22 levels primarily reflecting the impact of planned turnaround activities completed at Primrose during the quarter and natural field declines, partially offset by new production from pad additions at Kirby.

- Thermal in situ operating costs averaged $14.59/bbl (US$10.87/bbl) in Q2/23, a decrease of 23% over Q2/22 levels, largely reflecting lower natural gas fuel costs.

▪ Canadian Natural continues to deliver safe, reliable production from its long life low decline thermal in situ assets which have decades of strong capital efficient growth opportunities. Thermal in situ production is targeted to increase to an average of approximately 280,000 bbl/d in Q3/23, as a result of strong execution enabling the Company to optimize the production schedule on the new Primrose CSS pads, combined with the Kirby SAGD pads coming on stream earlier and ramping up ahead of plan. This represents production growth of approximately 30,000 bbl/d from Q4/22 levels, utilizing existing facility capacity. Highlights include:

- At Primrose, the Company is targeting to grow production by approximately 25,000 bbl/d to approximately 100,000 bbl/d in Q3/23 from Q4/22 levels, primarily from two CSS pads drilled in 2022.
- At Kirby, the Company is targeting to grow production by approximately 15,000 bbl/d from Q4/22 levels to approximately 65,000 bbl/d in Q4/23, through the development of four SAGD pads, the first of which came on production in late Q2/23. The three remaining pads are targeted to ramp up to full production capacity over the first nine months of 2024, at a pace of one pad per quarter.
- At Jackfish, two SAGD pads were drilled in the first half of 2023, with production from these pads targeted to ramp up to their full production capacities in Q3/24 and Q4/24 respectively, supporting continued high utilization rates.

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

- Based on the forward strip as of July 24, 2023, tighter average WCS differentials of approximately US$15.00/bbl in Q3/23 and Q4/23 are an improvement compared to Q1/23 when WCS differentials averaged approximately US$25.00/bbl. Thermal in situ production is well-positioned to capture strong pricing, generating significant free cash flow.
- Canadian Natural has been piloting solvent enhanced oil recovery technology on certain of its thermal in situ assets with an objective to increase bitumen production, reduce the Steam to Oil Ratio ("SOR"), reduce GHG intensity and realize high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - After a successful solvent pilot at Kirby South, the Company has completed engineering and design of a commercial scale solvent SAGD pad development at Kirby North. The Company targets to begin facility module installations in Q3/23, followed by solvent injection in mid-2024.
  - At Primrose, the Company is currently piloting solvent enhanced oil recovery in the steam flood area and is targeting SOR and GHG intensity reductions of 40% to 45%, with solvent recovery greater than 70%. Results to-date have been positive and the Company targets to complete the pilot in Q4/23.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Natural gas production (MMcf/d)	**2,072**	2,127	2,089	**2,100**	2,039
Net wells targeting natural gas	**21**	21	20	**42**	43
Net successful wells drilled	**21**	21	20	**42**	43
Success rate	**100%**	100%	100%	**100%**	100%

- Canadian Natural averaged 2,072 MMcf/d of natural gas production in North America in Q2/23, comparable to Q2/22 levels, reflecting strong drilling results from its liquids-rich Montney and Deep Basin wells, partially offset by the impact of wildfires, a third-party pipeline outage and natural field declines.
  - North America natural gas operating costs averaged $1.35/Mcf in Q2/23, an increase of 17% over Q2/22 levels, primarily due to higher service and power costs, as well as lower production volumes resulting from wildfires and a third-party pipeline outage.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil production (bbl/d)	**26,520**	27,331	25,907	**26,923**	28,789
Natural gas production (MMcf/d)	**13**	12	16	**12**	17

- International E&P crude oil production volumes averaged 26,520 bbl/d in Q2/23, comparable to Q2/22 levels.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Synthetic crude oil production (bbl/d) (1)(2)	**355,246**	458,228	356,953	**406,453**	393,188

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

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

- Canadian Natural continues to focus on safe, reliable, effective and efficient operations of its world class Oil Sands Mining and Upgrading assets to deliver high value SCO, with production averaging 355,246 bbl/d in Q2/23, comparable to Q2/22 levels. Major planned turnarounds were completed at both Horizon and the non-operated Scotford Upgrader, with a total combined impact to Q2/23 production of approximately 120,000 bbl/d.

- Following the completion of planned turnarounds at Horizon and the non-operated Scotford Upgrader, the Company achieved strong monthly average production in July 2023 of approximately 513,000 bbl/d of SCO.
- Oil Sands Mining and Upgrading operating costs remained strong, averaging $31.28/bbl (US$23.29/bbl) in Q2/23, a decrease of 7% compared to Q2/22 levels. Operating costs in Q2/23 and Q2/22 both reflect lower production volumes due to planned turnaround activities.

▪ The Company realized strong SCO pricing averaging US$76.67/bbl in Q2/23, capturing a US$2.92/bbl premium to WTI, generating significant free cash flow for the Company.

▪ Approximately 47% of the Company's total 2023 budgeted liquids production consists of high value SCO. Based on the forward strip as of July 24, 2023, these high margin SCO barrels will capture strong pricing with an average premium to WTI pricing of approximately US$3.00/bbl in Q3/23 and Q4/23, generating significant free cash flow for the Company.

▪ At Horizon, the reliability enhancement project is targeting to add approximately 14,000 bbl/d of additional SCO production capacity in 2025 as a result of shifting the maintenance schedule from once per year to once every two years, reducing downtime for maintenance activities and increasing overall reliability at Horizon.

- During the planned turnaround at Horizon and as part of the reliability enhancement project, the Company completed tie-ins of two furnaces. In August 2023, both furnaces are targeted to be operational, increasing SCO production capacity by approximately 5,000 bbl/d, which is included in the Company's 2023 production guidance.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 73.75**	$ 76.11	$ 108.42	**$ 74.92**	$ 101.44
WCS heavy differential as a percentage of WTI (%) (2)	**20%**	33%	12%	**27%**	14%
SCO benchmark price (US$/bbl)	**$ 76.67**	$ 78.18	$ 114.35	**$ 77.42**	$ 103.76
Condensate benchmark price (US$/bbl)	**$ 72.28**	$ 79.83	$ 108.35	**$ 76.03**	$ 102.29
Exploration & Production liquids realized pricing (C$/bbl) (3)(4)	**$ 72.06**	$ 58.85	$ 115.26	**$ 65.58**	$ 104.27
SCO realized pricing (C$/bbl) (4)(5)	**$ 95.08**	$ 96.07	$ 137.60	**$ 95.64**	$ 123.42
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.22**	$ 4.12	$ 5.95	**$ 3.17**	$ 5.15
Natural gas realized pricing (C$/Mcf) (5)	**$ 2.53**	$ 4.27	$ 7.93	**$ 3.41**	$ 6.63

(1) West Texas Intermediate ("WTI").

(2) Western Canadian Select ("WCS").

(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

(4) Non-GAAP ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2023 dated August 2, 2023.

(5) Pricing is net of blending costs and excluding risk management activities.

▪ Canadian Natural has a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, thermal in situ bitumen and SCO.

▪ WTI prices were strong in Q2/23, averaging US$73.75/bbl in Q2/23, however remain volatile as a result of geopolitical factors and demand concerns driven by an increased risk of a global recession due to persistent inflation and rising interest rates.

▪ SCO benchmark pricing continued to represent a price premium of US$2.92/bbl to WTI pricing as a result of strong North American demand for refined products, with the SCO benchmark price averaging US$76.67/bbl in Q2/23.

- Approximately 47% of the Company's total 2023 budgeted liquids production consists of high value SCO. Based on the forward strip as of July 24, 2023, these high margin SCO barrels will capture strong pricing with an average premium to WTI pricing of approximately US$3.00/bbl in Q3/23 and Q4/23, generating significant free cash flow for the Company.

▪ The narrowing of the WCS differential as a percentage of WTI to 20% in Q2/23 compared to 33% in Q1/23 reflects the completion of the US Strategic Petroleum Reserve ("SPR") releases and the return of certain refineries in the US Midwest, strengthening price realizations for the Company's heavy crude oil and bitumen production.

  - Based on the forward strip as of July 24, 2023, the tighter average WCS differential of approximately US$15.00/bbl in Q3/23 and Q4/23 is an improvement compared to Q1/23 when WCS differentials averaged approximately US$25.00/bbl. Thermal in situ and heavy crude oil production are well-positioned to capture strong pricing, generating significant free cash flow.

▪ The North West Redwater ("NWR") refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 79,112 BOE/d in Q2/23.

▪ Canadian Natural has diversified sales points which limits exposure to any one particular market and maximizes value for our shareholders. Based on production volumes during the first half of 2023, the Company purchased natural gas at AECO to use in our operations, offsetting the equivalent of approximately 37% of our natural gas production, with approximately 26% of our natural gas production sold at AECO/Station 2 pricing, and approximately 37% exported and sold to other North American and international markets.

  - The monthly AECO natural gas benchmark price averaged $2.22/GJ in Q2/23, a 63% decrease from Q2/22. Weaker natural gas prices primarily reflect increased North American production and higher storage levels.

▪ Canadian Natural has been a supporter of incremental pipeline projects to ensure Canadian crude oil and natural gas can access global markets to deliver the most responsible and leading ESG production that the world needs.

  - On May 30, 2023, Trans Mountain Corporation ("Trans Mountain") provided an update on its 590,000 bbl/d Trans Mountain Expansion project ("TMX"), on which Canadian Natural has committed 94,000 bbl/d. Trans Mountain continues to anticipate mechanical completion of the pipeline to occur at the end of 2023 with commercial service expected to occur in Q1/24. Trans Mountain estimates the total cost of this project to be approximately $30.9 billion.

    ◦ Trans Mountain has filed an application with the Canada Energy Regulator ("CER") to set the interim tolls for transportation on the TMX expansion.

FINANCIAL REVIEW

▪ The Company continues to implement proven strategies including its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. The Company's adjusted funds flow generation, credit facilities, US commercial paper program, access to capital markets, diverse asset base and flexible capital expenditure program all support a strong financial position and provide the appropriate financial resources for the near-, mid- and long-term.

▪ Safe, effective and efficient operations combined with our high quality, long life low decline asset base generated quarterly free cash flow of approximately $0.4 billion after dividend payments of approximately $1.0 billion and base capital expenditures of approximately $1.4 billion (excluding net acquisitions and strategic growth capital of approximately $0.3 billion in the quarter, as per the Company's free cash flow allocation policy).

▪ The Company's free cash flow allocation policy provides that when net debt is between $10 billion and $15 billion, 50% of free cash flow will be allocated to share repurchases and 50% of free cash flow will be allocated to the balance sheet, less strategic growth / acquisition opportunities. Free cash flow for the purpose of the policy is defined as adjusted funds flow less dividends, less base capital. When net debt reaches $10 billion, returns to shareholders increases to 100% of free cash flow with the free cash flow definition adjusted to define free cash flow as adjusted funds flow less dividends and less total capital expenditures in the year. This is a reflection of the Board of Director's confidence in the sustainability and resilience of the Company to support accelerating incremental shareholder returns to 100% of free cash flow.

▪ Returns to shareholders in Q2/23 were strong, totaling approximately $1.5 billion, comprised of approximately $1.0 billion of dividends and approximately $0.5 billion of share repurchases.

▪ In Q2/23, the Company repurchased approximately 6.4 million common shares for cancellation at a weighted average price of $76.57 per share for a total of approximately $0.5 billion.

  - Canadian Natural increased its sustainable and growing quarterly dividend in March 2023 to $0.90 per common share, marking 2023 as the 23rd consecutive year of dividend increases and demonstrating the confidence that the Board of Directors has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline asset base.

- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with net debt of approximately $12.0 billion and significant liquidity of approximately $5.6 billion at the end of Q2/23.
  - Undrawn revolving bank credit facilities totaling approximately $5.0 billion were available at June 30, 2023. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $5.6 billion. At June 30, 2023, the Company had $437 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - In June 2023, the Company extended its $2,425 million revolving credit facility by three years, originally maturing June 2024, to June 2027.
- Year-to-date, up to and including August 2, 2023, the Company has returned approximately $4.3 billion to shareholders through approximately $2.9 billion in dividends and $1.4 billion through the repurchase and cancellation of approximately 17.6 million common shares.
- Subsequent to quarter end, Canadian Natural declared a quarterly dividend of $0.90 per share, payable on October 5, 2023 to shareholders of record on September 15, 2023.
- Subsequent to quarter end, in July 2023, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which expire August 2025, replacing the Company's previous base shelf prospectuses which would have expired in August 2023. 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.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE HIGHLIGHTS

Canada and Canadian Natural are well positioned to deliver affordable, reliable, safe and responsibly produced energy that the world needs, through leading ESG performance. 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 for GHG emissions reductions. Canadian Natural continues to invest in a range of technologies to reduce emissions, such as 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 GHG technologies across our assets, including opportunities for methane emissions reduction, which will enhance the Company’s environmental performance and long-term sustainability.

Sustainability Reporting

Canadian Natural has been producing its sustainability report, the Stewardship Report to Stakeholders, since 2004 to report on the Company's ongoing commitment to environmental performance, social responsibility and continuous improvement. Today, Canadian Natural released its 2022 Stewardship Report to Stakeholders in conjunction with Q2/23 results, which is now available on the Company's website at www.cnrl.com. This report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. It provides a performance overview across the full range of the Company’s operations in Western Canada, the UK portion of the North Sea and Offshore Africa.

The Company aligns its reporting with recommendations from the Task Force on Climate-Related Financial Disclosures, the reporting framework from the Sustainability Accounting Standards Board and the Global Reporting Initiative. Canadian Natural’s 2022 report includes independent third party reasonable assurance on our scope 1 and 2 emissions (including methane emissions) and limited assurance on our scope 3 emissions.

Highlights from the Company's 2022 report include:

- 43% reduction in total recordable injury frequency (“TRIF”) and an 80% reduction in corporate lost time incident frequency (“LTI”) from 2018 to 2022.
- Invested approximately $587 million in research, technology development and deployment, with $151 million in GHG reduction technology and implementation projects.
- Announced a new environmental target: 40% reduction in corporate scope 1 and 2 absolute GHG emissions by 2035 from a 2020 baseline.
- Continued reductions to corporate direct GHG emissions intensity with an 8% reduction from 2018 to 2022.
- 50% reduction in 2022 in absolute methane emissions in its North America E&P operations from its 2016 baseline.
- 66% reduction in 2022 of in situ fresh water use intensity from its 2017 baseline.
- 36% reduction in 2022 of oil sands mining fresh river water use intensity from its 2017 baseline.
- Abandoned 3,121 inactive wells in our North America E&P operations in 2022. The Company has abandoned more than 3,000 wells per year in each of 2022 and 2021. At this pace, the Company would be able to achieve 100% abandonment of its current inventory of inactive wells in approximately 10 years.
- Awarded approximately $684 million in contracts with Indigenous businesses, a 20% increase from 2021.

Environmental Targets

Canadian Natural is committed to reducing its environmental footprint and as previously announced, has committed to the following environmental targets:

- 40% reduction in corporate Scope 1 and Scope 2 absolute GHG emissions by 2035, from a 2020 baseline.
- 50% reduction in North America E&P (including thermal in situ) methane emissions by 2030, from a 2016 baseline.
- 40% reduction in thermal in situ fresh water usage intensity by 2026, from a 2017 baseline.
- 40% reduction in mining fresh river water usage intensity by 2026, from a 2017 baseline.

Pathways Alliance

The six major oil sands companies in the Pathways Alliance ("Pathways"), including Canadian Natural, operate approximately 95% of Canada’s oil sands production. The goal of this unique alliance is to support Canada in meeting its climate commitments and position Canada to be the preferred source of crude oil globally. Working collectively with the federal and provincial governments, Pathways has a goal to achieve net zero GHG emissions from oil sands operations by 2050 and is pursuing realistic and workable solutions to deliver significant emissions reductions.

Pathways recognizes that there are multiple technologies towards achieving net zero emissions in the oil sands, including the deployment of existing and emerging GHG reduction technologies such as direct air capture, clean hydrogen, process improvements, energy efficiency, fuel switching and electrification. Pathways has a defined plan, including its foundational CCS project involving a CO_2 trunkline connecting Fort McMurray and Cold Lake to a carbon sequestration hub. In January 2023, Pathways entered into a Carbon Sequestration Evaluation Agreement with the Government of Alberta. During the first half of 2023, technical teams advanced detailed evaluations for the proposed storage hub to enhance understanding of the geology in the hub region. The proposed carbon storage hub would be one of the world's largest carbon capture and storage projects and would be connected to a transportation line that would initially gather captured CO_2 from an anticipated 14 oil sands facilities in the Fort McMurray, Christina Lake and Cold Lake regions. The plan is to grow the transportation network to include over 20 oil sands facilities, and to accommodate other industries in the region interested in CCS.

Members of Pathways continue to advance community engagement and environmental field programs to minimize the project’s environmental disturbance. Project engineering and environmental field programs are on track for this anchor project to meet timelines set out, subject to government support on these efforts. Stakeholder engagement continues to progress with Indigenous and local communities in northern Alberta related to the Pathways CCS project.

Government Support for Emissions Reductions and Carbon Capture, Utilization and Storage

Canadian Natural is a leader in CCS and GHG reduction projects and sees many opportunities to work collaboratively with industry peers and governments to advance investments in CCS and to achieve meaningful GHG emissions reductions in support of Canada's climate goals. The Government of Canada has proposed an investment tax credit for CCS projects in Canada. The Government of Alberta's 2023 Budget announcement on February 28, 2023 included support for CCS projects and coordination with federal CCS initiatives.

In addition, the Government of Alberta released its Emissions Reduction and Energy Development Plan ("ERED") on April 19, 2023, which outlines the importance of ensuring a globally competitive oil and natural gas industry while reducing emissions and an aspiration to achieve net zero by 2050. By working together, industry and governments have the opportunity to help achieve climate goals, meet economic objectives and support Canada's role in energy security.

Special Note Regarding Non-GAAP and Other Financial Measures

This press release includes references to 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 press release, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three and six months ended June 30, 2023, dated August 2, 2023.

Free Cash Flow

Free cash flow is a non-GAAP financial measure that represents adjusted funds flow adjusted for base capital expenditures and dividends on common shares. 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 debt.

($ millions)	Three Months Ended **Jun 30 2023**	Three Months Ended Mar 31 2023	Three Months Ended Jun 30 2022	Six Months Ended **Jun 30 2023**	Six Months Ended Jun 30 2022
Adjusted funds flow (1)	**$ 2,742**	$ 3,429	$ 5,432	**$ 6,171**	$ 10,407
Less: Base capital expenditures (2)	**$ 1,385**	$ 1,117	$ 1,266	**$ 2,502**	$ 2,110
Dividends on common shares	**$ 989**	$ 938	$ 871	**$ 1,927**	$ 1,560
Free cash flow	**$ 368**	$ 1,374	$ 3,295	**$ 1,742**	$ 6,737

(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 six months ended June 30, 2023, dated August 2, 2023.

(2) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of Company's MD&A for the three and six months ended June 30, 2023, dated August 2, 2023 for more details on net capital expenditures.

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.

Long-term Debt, net

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

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.

Break-even WTI Price

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

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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", "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 expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital 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, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), the Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project 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 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 impact of the Pathways Alliance ("Pathways") initiative and activities, government support for Pathways and the ability to achieve net zero emissions from oil production, 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 the Russian invasion of Ukraine, continuing effects of the novel coronavirus ("COVID-19") pandemic, 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, 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 and other cyber-related crime; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the Company's ability to implement strategies and leverage technologies to meet climate change initiatives and emissions targets; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' 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 mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, 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 and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); 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; 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 Currency, Financial Information and Production

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three and six months ended June 30, 2023, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2022. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s financial statements for the three and six months ended June 30, 2023 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.

The following discussion and analysis refers primarily to the Company's financial results for the three and six months ended June 30, 2023 in relation to the comparable periods in 2022 and the first quarter of 2023. 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, 2022, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated August 2, 2023.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		Three Months Ended Jun 30 2023	Mar 31 2023	Jun 30 2022	Six Months Ended Jun 30 2023	Jun 30 2022
Product sales [1]		**$ 8,846**	$ 9,548	$ 13,812	**$ 18,394**	$ 25,944
Crude oil and NGLs		**$ 8,115**	$ 8,412	$ 11,727	**$ 16,527**	$ 22,500
Natural gas		**$ 522**	$ 851	$ 1,605	**$ 1,373**	$ 2,607
Net earnings		**$ 1,463**	$ 1,799	$ 3,502	**$ 3,262**	$ 6,603
Per common share	– basic	**$ 1.34**	$ 1.63	$ 3.04	**$ 2.97**	$ 5.70
	– diluted	**$ 1.32**	$ 1.62	$ 3.00	**$ 2.94**	$ 5.63
Adjusted net earnings from operations [2]		**$ 1,256**	$ 1,881	$ 3,800	**$ 3,137**	$ 7,176
Per common share	– basic [3]	**$ 1.15**	$ 1.71	$ 3.30	**$ 2.86**	$ 6.20
	– diluted [3]	**$ 1.14**	$ 1.69	$ 3.26	**$ 2.83**	$ 6.12
Cash flows from operating activities		**$ 2,745**	$ 1,295	$ 5,896	**$ 4,040**	$ 8,749
Adjusted funds flow [2]		**$ 2,742**	$ 3,429	$ 5,432	**$ 6,171**	$ 10,407
Per common share	– basic [3]	**$ 2.50**	$ 3.12	$ 4.72	**$ 5.62**	$ 8.99
	– diluted [3]	**$ 2.48**	$ 3.08	$ 4.66	**$ 5.57**	$ 8.87
Cash flows used in investing activities		**$ 1,560**	$ 1,153	$ 1,345	**$ 2,713**	$ 2,596
Net capital expenditures [2]		**$ 1,669**	$ 1,394	$ 1,450	**$ 3,063**	$ 2,905

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

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the six months ended June 30, 2023 were $3,262 million compared with $6,603 million for the six months ended June 30, 2022. Net earnings for the six months ended June 30, 2023 included non-operating income, net of tax, of $125 million compared with non-operating losses of $573 million for the six months ended June 30, 2022 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on the settlement of the cross currency swap, the gain from investments, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2023 were $3,137 million compared with $7,176 million for the six months ended June 30, 2022.

Net earnings for the second quarter of 2023 were $1,463 million compared with $3,502 million for the second quarter of 2022 and $1,799 million for the first quarter of 2023. Net earnings for the second quarter of 2023 included non-operating income, net of tax, of $207 million compared with non-operating losses of $298 million for the second quarter of 2022 and non-operating losses of $82 million for the first quarter of 2023 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on the settlement of the cross currency swap, the (gain) loss from investments, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the second quarter of 2023 were $1,256 million compared with $3,800 million for the second quarter of 2022 and $1,881 million for the first quarter of 2023.

The decrease in net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2023 from the three and six months ended June 30, 2022 primarily reflected:

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

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

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

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower crude oil and NGLs sales volumes in the North America segment; and
- lower natural gas sales volumes and realized natural gas pricing in the North America segment;

partially offset by:

- higher crude oil and NGLs netbacks in the North America segment.

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the settlement of the cross currency swap, and the (gain) loss from investments, 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 six months ended June 30, 2023 were $4,040 million compared with $8,749 million for the six months ended June 30, 2022. Cash flows from operating activities for the second quarter of 2023 were $2,745 million compared with $5,896 million for the second quarter of 2022 and $1,295 million for the first quarter of 2023. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for the six months ended June 30, 2023 was $6,171 million compared with $10,407 million for the six months ended June 30, 2022. Adjusted funds flow for the second quarter of 2023 was $2,742 million compared with $5,432 million for the second quarter of 2022 and $3,429 million for the first quarter of 2023. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program.

Production Volumes

Crude oil and NGLs production before royalties for the second quarter of 2023 of 846,909 bbl/d was comparable with 860,338 bbl/d for the second quarter of 2022, and decreased 12% from 962,908 bbl/d for the first quarter of 2023. Natural gas production before royalties for the second quarter of 2023 of 2,085 MMcf/d was comparable with 2,105 MMcf/d for the second quarter of 2022, and decreased 3% from 2,139 MMcf/d for the first quarter of 2023. Total production before royalties for the second quarter of 2023 of 1,194,326 BOE/d was comparable with 1,211,147 BOE/d for the second quarter of 2022, and decreased 9% from 1,319,391 BOE/d for the first quarter of 2023. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices [(1)] averaged $72.06 per bbl for the second quarter of 2023, a decrease of 37% compared with $115.26 per bbl for the second quarter of 2022, and an increase of 22% from $58.85 per bbl for the first quarter of 2023. The realized natural gas price decreased 68% to average $2.53 per Mcf for the second quarter of 2023 from $7.93 per Mcf for the second quarter of 2022, and decreased 41% from $4.27 per Mcf for the first quarter of 2023. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 31% to average $95.08 per bbl for the second quarter of 2023 from $137.60 per bbl for the second quarter of 2022, and was comparable with $96.07 per bbl for the first quarter of 2023. 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.

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

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense [(1)] averaged \$18.38 per bbl for the second quarter of 2023, a decrease of 6% from \$19.58 per bbl for the second quarter of 2022, and an increase of 9% from \$16.93 per bbl for the first quarter of 2023. Natural gas production expense [(1)] averaged \$1.37 per Mcf for the second quarter of 2023, an increase of 17% from \$1.17 per Mcf for the second quarter of 2022, and a decrease of 7% from \$1.47 per Mcf for the first quarter of 2023. In the Oil Sands Mining and Upgrading segment, production expense [(1)] averaged \$31.28 per bbl for the second quarter of 2023, a decrease of 7% from \$33.76 per bbl for the second quarter of 2022, and an increase of 25% from \$25.06 per bbl for the first quarter of 2023. 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)	**Jun 30 2023**	Mar 31 2023	Dec 31 2022	Sep 30 2022
Product sales [(1)]	**\$ 8,846**	\$ 9,548	\$ 11,012	\$ 12,574
Crude oil and NGLs	**\$ 8,115**	\$ 8,412	\$ 9,508	\$ 11,001
Natural gas	**\$ 522**	\$ 851	\$ 1,287	\$ 1,342
Net earnings	**\$ 1,463**	\$ 1,799	\$ 1,520	\$ 2,814
Net earnings per common share				
– basic	**\$ 1.34**	\$ 1.63	\$ 1.37	\$ 2.52
– diluted	**\$ 1.32**	\$ 1.62	\$ 1.36	\$ 2.49

($ millions, except per common share amounts)	Jun 30 2022	Mar 31 2022	Dec 31 2021	Sep 30 2021
Product sales [(1)]	\$ 13,812	\$ 12,132	\$ 10,190	\$ 8,521
Crude oil and NGLs	\$ 11,727	\$ 10,773	\$ 8,979	\$ 7,607
Natural gas	\$ 1,605	\$ 1,002	\$ 958	\$ 694
Net earnings	\$ 3,502	\$ 3,101	\$ 2,534	\$ 2,202
Net earnings per common share				
– basic	\$ 3.04	\$ 2.66	\$ 2.16	\$ 1.87
– diluted	\$ 3.00	\$ 2.63	\$ 2.14	\$ 1.86

(1) Further details related to product sales for the three months ended June 30, 2023 and 2022 are disclosed in note 17 to the financial statements.

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

- **Crude oil pricing** – Fluctuating 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 COVID-19 and in connection with governmental responses to COVID-19, and the impact of the Russian invasion of Ukraine on worldwide benchmark pricing; the impact of shale oil production in North America; 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** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, 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.

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

- **Crude oil and NGLs sales volumes** – Fluctuations in production from the Kirby and Jackfish Thermal Oil Sands Projects, fluctuations in production due to the cyclic nature of the Primrose thermal oil projects, fluctuations in the Company’s drilling program in North America and the International segments, natural decline rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and wildfires and a third-party pipeline outage in the North America 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 North America and the International segments, natural decline rates, the impact and timing of acquisitions, and wildfires and a third-party pipeline outage in the North America 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 and energy costs, inflationary cost pressures, cost optimizations across all segments, the impact and timing of acquisitions, 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 including the impact and timing of acquisitions and dispositions, 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, and a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea at December 31, 2022.
- **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 Petroleum Revenue Tax ("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, partially offset by the impact of any cross currency swap hedges outstanding.
- **(Gain) loss from investments; gain on acquisitions** – Fluctuations due to the (gain) loss from the investments in PrairieSky Royalty Ltd. and Inter Pipeline Ltd. shares, and the recognition of gains on acquisitions.

BUSINESS ENVIRONMENT

Risks and Uncertainties

Global benchmark crude oil prices continued to trend downward in the second quarter of 2023, as demand growth concerns, rising interest rates and recessionary fears continued to put downward pressure on global crude oil pricing. Following the OPEC+ decision in early June 2023 to extend production cuts through 2024, further voluntary production cuts were announced to support the stability of the market. Additionally, 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 June 30, 2023, the Company had undrawn revolving bank credit facilities of $4,954 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,600 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.

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

Benchmark Commodity Prices

(Average for the period)	Three Months Ended **Jun 30 2023**	Mar 31 2023	Jun 30 2022	Six Months Ended **Jun 30 2023**	Jun 30 2022
WTI benchmark price (US$/bbl)	**$ 73.75**	$ 76.11	$ 108.42	**$ 74.92**	$ 101.44
Dated Brent benchmark price (US$/bbl)	**$ 78.37**	$ 81.24	$ 112.67	**$ 79.79**	$ 105.96
WCS Heavy Differential from WTI (US$/bbl)	**$ 15.07**	$ 24.74	$ 12.80	**$ 19.87**	$ 13.70
SCO price (US$/bbl)	**$ 76.67**	$ 78.18	$ 114.35	**$ 77.42**	$ 103.76
Condensate benchmark price (US$/bbl)	**$ 72.28**	$ 79.83	$ 108.35	**$ 76.03**	$ 102.29
Condensate Differential from WTI (US$/bbl)	**$ 1.47**	$ (3.72)	$ 0.07	**$ (1.11)**	$ (0.85)
NYMEX benchmark price (US$/MMBtu)	**$ 2.10**	$ 3.43	$ 7.17	**$ 2.76**	$ 6.05
AECO benchmark price (C$/GJ)	**$ 2.22**	$ 4.12	$ 5.95	**$ 3.17**	$ 5.15
US/Canadian dollar average exchange rate (US$)	**$ 0.7447**	$ 0.7393	$ 0.7832	**$ 0.7420**	$ 0.7865

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, and its product revenues continued to be impacted by the volatility of the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$74.92 per bbl for the six months ended June 30, 2023, a decrease of 26% from US$101.44 per bbl for the six months ended June 30, 2022. WTI averaged US$73.75 per bbl for the second quarter of 2023, a decrease of 32% from US$108.42 per bbl for the second quarter of 2022, and a decrease of 3% from US$76.11 per bbl for the first quarter of 2023.

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$79.79 per bbl for the six months ended June 30, 2023, a decrease of 25% from US$105.96 per bbl for the six months ended June 30, 2022. Brent averaged US$78.37 per bbl for the second quarter of 2023, a decrease of 30% from US$112.67 per bbl for the second quarter of 2022, and a decrease of 4% from US$81.24 per bbl for the first quarter of 2023.

The decrease in WTI and Brent pricing for the three and six months ended June 30, 2023 from the comparable periods primarily reflected concerns of lower global demand as a result of persistent inflation and the resulting increase in interest rates.

The WCS Heavy Differential averaged US$19.87 per bbl for the six months ended June 30, 2023, compared with US$13.70 per bbl for the six months ended June 30, 2022. The WCS Heavy Differential averaged US$15.07 per bbl for the second quarter of 2023, compared with US$12.80 per bbl for the second quarter of 2022, and US$24.74 per bbl for the first quarter of 2023. The widening of the WCS Heavy Differential for the six months ended June 30, 2023 from the comparable period in 2022 primarily reflected weaker global sour crude oil pricing in part due to the availability of discounted Russian crude oil in the market, and US Strategic Petroleum Reserve sour crude oil releases that carried over into the first quarter of 2023. The narrowing of the WCS Heavy Differential for the second quarter of 2023 from the first quarter of 2023 primarily reflected incremental demand due to the restart of certain refineries in the US Midwest, and the spring production turnarounds reducing available supply.

The SCO price averaged US$77.42 per bbl for the six months ended June 30, 2023, a decrease of 25% from US$103.76 per bbl for the six months ended June 30, 2022. The SCO price averaged US$76.67 per bbl for the second quarter of 2023, a decrease of 33% from US$114.35 per bbl for the second quarter of 2022, and comparable with US$78.18 per bbl for the first quarter of 2023. The decrease in SCO pricing for the three and six months ended June 30, 2023 from the comparable periods primarily reflected the decrease in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.76 per MMBtu for the six months ended June 30, 2023, a decrease of 54% from US$6.05 per MMBtu for the six months ended June 30, 2022. NYMEX natural gas prices averaged US$2.10 per MMBtu for the second quarter of 2023, a decrease of 71% from US$7.17 per MMBtu for the second quarter of 2022, and a decrease of 39% from US$3.43 per MMBtu for the first quarter of 2023. The decrease in NYMEX natural gas prices for the three and six months ended June 30, 2023 from the comparable periods primarily reflected lower storage draws due to mild winter weather, combined with increased production in North America. Additionally, lower global LNG prices amid ample supply and a milder winter put downward pressure on NYMEX benchmark prices.

AECO natural gas prices averaged $3.17 per GJ for the six months ended June 30, 2023, a decrease of 38% from $5.15 per GJ for the six months ended June 30, 2022. AECO natural gas prices averaged $2.22 per GJ for the second quarter of 2023, a decrease of 63% from $5.95 per GJ for the second quarter of 2022, and a decrease of 46% from $4.12 per GJ for the first quarter of 2023. The decrease in AECO natural gas prices for the three and six months ended June 30, 2023 from the comparable periods primarily reflected NYMEX benchmark pricing, and increased production levels in the Western Canadian Sedimentary Basin.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**465,143**	477,349	477,478	**471,212**	480,860
North America – Oil Sands Mining and Upgrading (1)	**355,246**	458,228	356,953	**406,453**	393,188
International – Exploration and Production					
North Sea	**12,699**	13,240	10,788	**12,968**	13,360
Offshore Africa	**13,821**	14,091	15,119	**13,955**	15,429
Total International (2)	**26,520**	27,331	25,907	**26,923**	28,789
Total Crude oil and NGLs	**846,909**	962,908	860,338	**904,588**	902,837
Natural gas (MMcf/d) (3)					
North America	**2,072**	2,127	2,089	**2,100**	2,039
International					
North Sea	**2**	3	2	**2**	2
Offshore Africa	**11**	9	14	**10**	15
Total International	**13**	12	16	**12**	17
Total Natural gas	**2,085**	2,139	2,105	**2,112**	2,056
Total Barrels of oil equivalent (BOE/d)	**1,194,326**	1,319,391	1,211,147	**1,256,513**	1,245,473
Product mix					
Light and medium crude oil and NGLs	**11%**	10%	11%	**11%**	11%
Pelican Lake heavy crude oil	**4%**	4%	4%	**4%**	4%
Primary heavy crude oil	**6%**	6%	6%	**6%**	5%
Bitumen (thermal oil)	**20%**	18%	21%	**19%**	21%
Synthetic crude oil (1)	**30%**	35%	29%	**32%**	32%
Natural gas	**29%**	27%	29%	**28%**	27%
Percentage of gross revenue (1) (4) (5)					
Crude oil and NGLs	**93%**	90%	87%	**91%**	89%
Natural gas	**7%**	10%	13%	**9%**	11%

(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.

(3) Natural gas production volumes approximate sales volumes.

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

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**388,670**	396,482	366,389	**392,555**	376,449
North America – Oil Sands Mining and Upgrading	**301,239**	411,434	265,527	**356,033**	320,948
International – Exploration and Production					
North Sea	**12,654**	13,240	10,770	**12,945**	13,325
Offshore Africa	**12,343**	12,740	13,815	**12,540**	14,409
Total International	**24,997**	25,980	24,585	**25,485**	27,734
Total Crude oil and NGLs	**714,906**	833,896	656,501	**774,073**	725,131
Natural gas (MMcf/d)					
North America	**2,014**	1,988	1,855	**2,001**	1,842
International					
North Sea	**2**	3	2	**2**	2
Offshore Africa	**10**	9	11	**10**	13
Total International	**12**	12	13	**12**	15
Total Natural gas	**2,026**	2,000	1,868	**2,013**	1,857
Total Barrels of oil equivalent (BOE/d)	**1,052,602**	1,167,300	967,847	**1,109,635**	1,034,663

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 six months ended June 30, 2023 averaged 904,588 bbl/d, which was comparable with 902,837 bbl/d for the six months ended June 30, 2022. Crude oil and NGLs production for the second quarter of 2023 averaged 846,909 bbl/d, comparable with 860,338 bbl/d for the second quarter of 2022, and a decrease of 12% from 962,908 bbl/d for the first quarter of 2023. The decrease in crude oil and NGLs production for the second quarter of 2023 from the first quarter of 2023 primarily reflected the completion of planned turnaround activities at Horizon and the non-operated Scotford Upgrader ("Scotford") in the second quarter of 2023.

Natural gas production before royalties for the six months ended June 30, 2023 of 2,112 MMcf/d increased 3% from 2,056 MMcf/d for the six months ended June 30, 2022. Natural gas production for the second quarter of 2023 of 2,085 MMcf/d was comparable with 2,105 MMcf/d for the second quarter of 2022, and decreased 3% from 2,139 MMcf/d for the first quarter of 2023. The increase in natural gas production for the six months ended June 30, 2023 from the comparable period in 2022 primarily reflected strong drilling results, partially offset by the impact of wildfires and a third-party pipeline outage, together with natural field declines. The decrease in natural gas production for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of wildfires, a third-party pipeline outage impacting both quarters, and natural field declines, partially offset by strong drilling results.

Despite the wildfires in Western Canada, the third-party pipeline outage in the first half of the year, and the previously announced unplanned outages at Horizon in January 2023, the Company's 2023 production is still targeted to be within the corporate guidance range of 1,330,000 BOE/d to 1,374,000 BOE/d, but closer to the lower end.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the six months ended June 30, 2023 averaged 471,212 bbl/d, comparable with 480,860 bbl/d for the six months ended June 30, 2022. North America crude oil and NGLs production for the second quarter of 2023 of 465,143 bbl/d decreased 3% from 477,478 bbl/d for the second quarter of 2022, and decreased 3% from 477,349 bbl/d for the first quarter of 2023. The decrease in North America crude oil and NGLs production for the second quarter of 2023 from the comparable periods primarily reflected the impact of wildfires, a third-party pipeline outage, planned turnaround activities in thermal, and natural field declines, partially offset by strong drilling results.

The Company’s thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 238,941 bbl/d for the second quarter of 2023, a decrease of 4% from 249,938 bbl/d for the second quarter of 2022, and comparable with 242,884 bbl/d for the first quarter of 2023. Thermal oil in the second quarter of 2023 as compared to prior periods primarily reflected the impact of planned turnaround activities completed at Primrose during the quarter, and natural field declines, offset by new production from pad additions at Kirby.

Pelican Lake heavy crude oil production before royalties for the second quarter of 2023 averaged 47,151 bbl/d, a decrease of 8% from 51,112 bbl/d for the second quarter of 2022, and comparable with 48,244 bbl/d for the first quarter of 2023, demonstrating Pelican Lake's long life low decline production.

Natural gas production before royalties for the six months ended June 30, 2023 averaged 2,100 MMcf/d, an increase of 3% from 2,039 MMcf/d for the six months ended June 30, 2022. Natural gas production for the second quarter of 2023 averaged 2,072 MMcf/d, comparable with 2,089 MMcf/d for the second quarter of 2022, and a decrease of 3% from 2,127 MMcf/d for the first quarter of 2023. The increase in natural gas production for the six months ended June 30, 2023 from the comparable period in 2022 primarily reflected strong drilling results, partially offset by the impact of wildfires and a third-party pipeline outage, together with natural field declines. The decrease in natural gas production for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of wildfires, a third-party pipeline outage impacting both quarters, and natural field declines, partially offset by strong drilling results.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the six months ended June 30, 2023 of 406,453 bbl/d increased 3% from 393,188 bbl/d for the six months ended June 30, 2022. SCO production for the second quarter of 2023 of 355,246 bbl/d was comparable with 356,953 bbl/d for the second quarter of 2022, and decreased 22% from 458,228 bbl/d for the first quarter of 2023. The decrease in SCO production for the second quarter of 2023 from the first quarter of 2023 primarily reflected the completion of planned turnaround activities at Horizon and Scotford during the second quarter.

International – Exploration and Production

International crude oil and NGLs production before royalties for the six months ended June 30, 2023 averaged 26,923 bbl/d, a decrease of 6% from 28,789 bbl/d for the six months ended June 30, 2022. International crude oil and NGLs production for the second quarter of 2023 averaged 26,520 bbl/d, comparable with 25,907 bbl/d for the second quarter of 2022, and a decrease of 3% from 27,331 bbl/d for the first quarter of 2023. The decrease in crude oil and NGLs production for the six months ended June 30, 2023 from the comparable period in 2022 and the decrease for the second quarter of 2023 from the first quarter of 2023 primarily 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 volumes held in various storage facilities or FPSOs, as follows:

(bbl)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022
International	**816,475**	1,912,388	460,436

During the first quarter of 2023, there were no crude oil liftings from the Company's platforms in the North Sea.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs ($/bbl) (1)					
Realized price (2)	**$ 72.06**	$ 58.85	$ 115.26	**$ 65.58**	$ 104.27
Transportation (2)	**4.57**	4.52	4.13	**4.54**	4.16
Realized price, net of transportation (2)	**67.49**	54.33	111.13	**61.04**	100.11
Royalties (3)	**11.09**	10.09	25.01	**10.60**	21.36
Production expense (4)	**18.38**	16.93	19.58	**17.67**	17.67
Netback (2)	**$ 38.02**	$ 27.31	$ 66.54	**$ 32.77**	$ 61.08
Natural gas ($/Mcf) (1)					
Realized price (5)	**$ 2.53**	$ 4.27	$ 7.93	**$ 3.41**	$ 6.63
Transportation (6)	**0.58**	0.55	0.52	**0.57**	0.50
Realized price, net of transportation	**1.95**	3.72	7.41	**2.84**	6.13
Royalties (3)	**0.07**	0.28	0.89	**0.17**	0.66
Production expense (4)	**1.37**	1.47	1.17	**1.42**	1.24
Netback	**$ 0.51**	$ 1.97	$ 5.35	**$ 1.25**	$ 4.23
Barrels of oil equivalent ($/BOE) (1)					
Realized price (2)	**$ 48.94**	$ 44.98	$ 88.07	**$ 46.98**	$ 78.91
Transportation (2)	**4.11**	4.03	3.70	**4.08**	3.72
Realized price, net of transportation (2)	**44.83**	40.95	84.37	**42.90**	75.19
Royalties (3)	**6.75**	6.56	17.03	**6.65**	14.47
Production expense (4)	**14.24**	13.51	14.44	**13.88**	13.57
Netback (2)	**$ 23.84**	$ 20.88	$ 52.90	**$ 22.37**	$ 47.15

(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.

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs ($/bbl) [1]					
North America [2]	**$ 69.44**	$ 57.99	$ 113.37	**$ 63.66**	$ 102.25
International average [3]	**$ 103.64**	$ 98.60	$ 144.82	**$ 102.58**	$ 136.71
North Sea [3]	**$ 106.39**	$ —	$ 146.06	**$ 106.39**	$ 137.67
Offshore Africa [3]	**$ 100.68**	$ 98.60	$ 143.33	**$ 99.94**	$ 135.90
Crude oil and NGLs average [2]	**$ 72.06**	$ 58.85	$ 115.26	**$ 65.58**	$ 104.27
Natural gas ($/Mcf) [1] [3]					
North America	**$ 2.47**	$ 4.22	$ 7.90	**$ 3.35**	$ 6.59
International average	**$ 13.16**	$ 13.76	$ 11.86	**$ 13.45**	$ 11.57
North Sea	**$ 9.48**	$ 11.81	$ 8.54	**$ 10.88**	$ 15.80
Offshore Africa	**$ 13.71**	$ 14.28	$ 12.31	**$ 13.97**	$ 10.88
Natural gas average	**$ 2.53**	$ 4.27	$ 7.93	**$ 3.41**	$ 6.63
Average ($/BOE) [1] [2]	**$ 48.94**	$ 44.98	$ 88.07	**$ 46.98**	$ 78.91

(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 decreased 38% to average $63.66 per bbl for the six months ended June 30, 2023 from $102.25 per bbl for the six months ended June 30, 2022. North America realized crude oil and NGLs prices decreased 39% to average $69.44 per bbl for the second quarter of 2023 from $113.37 per bbl for the second quarter of 2022, and increased 20% from $57.99 per bbl for the first quarter of 2023. The decrease for the three and six months ended June 30, 2023 from the comparable periods in 2022 was primarily due to lower WTI benchmark pricing and the widening of the WCS Heavy Differential. The increase for the second quarter of 2023 from the first quarter of 2023 primarily reflected the narrowing of the WCS Heavy Differential, partially offset by lower WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2023 contributed approximately 213,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 49% to average $3.35 per Mcf for the six months ended June 30, 2023 from $6.59 per Mcf for the six months ended June 30, 2022. North America realized natural gas prices decreased 69% to average $2.47 per Mcf for the second quarter of 2023 from $7.90 per Mcf for the second quarter of 2022, and decreased 41% from $4.22 per Mcf for the first quarter of 2023. The decrease for the three and six months ended June 30, 2023 from the comparable periods primarily reflected decreased AECO benchmark and export pricing.

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

	Three Months Ended		
(Quarterly average)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022
Wellhead Price [1]			
Light and medium crude oil and NGLs ($/bbl)	**$ 68.11**	$ 73.26	$ 105.36
Pelican Lake heavy crude oil ($/bbl)	**$ 76.66**	$ 67.57	$ 121.88
Primary heavy crude oil ($/bbl)	**$ 76.20**	$ 60.31	$ 122.14
Bitumen (thermal oil) ($/bbl)	**$ 66.51**	$ 48.60	$ 112.92
Natural gas ($/Mcf)	**$ 2.47**	$ 4.22	$ 7.90

(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 decreased 25% to average $102.58 per bbl for the six months ended June 30, 2023 from $136.71 per bbl for the six months ended June 30, 2022. International realized crude oil and NGLs prices decreased 28% to average $103.64 per bbl for the second quarter of 2023 from $144.82 per bbl for the second quarter of 2022, and increased 5% from $98.60 per bbl for the first quarter of 2023. Realized crude oil and NGLs prices per barrel 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 decrease in realized crude oil and NGLs prices for the three and six months ended June 30, 2023 from the comparable periods in 2022 reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar. The increase in realized crude oil and NGLs prices for the second quarter of 2023 compared to the first quarter of 2023 primarily reflected the timing of liftings.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.56**	$ 10.10	$ 26.24	**$ 10.83**	$ 22.39
International average	**$ 5.38**	$ 9.46	$ 5.78	**$ 6.24**	$ 4.87
North Sea	**$ 0.36**	$ —	$ 0.24	**$ 0.36**	$ 0.30
Offshore Africa	**$ 10.77**	$ 9.46	$ 12.36	**$ 10.30**	$ 8.78
Crude oil and NGLs average	**$ 11.09**	$ 10.09	$ 25.01	**$ 10.60**	$ 21.36
Natural gas ($/Mcf) (1)					
North America	**$ 0.07**	$ 0.27	$ 0.89	**$ 0.17**	$ 0.66
Offshore Africa	**$ 0.65**	$ 0.69	$ 2.20	**$ 0.67**	$ 1.57
Natural gas average	**$ 0.07**	$ 0.28	$ 0.89	**$ 0.17**	$ 0.66
Average ($/BOE) (1)	**$ 6.75**	$ 6.56	$ 17.03	**$ 6.65**	$ 14.47

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

North America

North America crude oil and NGLs and natural gas royalties for the three and six months ended June 30, 2023 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 17% of product sales for the six months ended June 30, 2023 compared with 22% of product sales for the six months ended June 30, 2022. Crude oil and NGLs royalty rates averaged approximately 17% of product sales for the second quarter of 2023 compared with 23% for the second quarter of 2022 and 17% for the first quarter of 2023. The decrease in royalty rates for the three and six months ended June 30, 2023 from the comparable periods in 2022 was primarily due to lower benchmark prices, together with the widening of the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 5% of product sales for the six months ended June 30, 2023 compared with 10% of product sales for the six months ended June 30, 2022. Natural gas royalty rates averaged approximately 3% of product sales for the second quarter of 2023 compared with 11% for the second quarter of 2022 and 6% for the first quarter of 2023. The decrease in royalty rates for the three and six months ended June 30, 2023 from the comparable periods was primarily due to lower benchmark prices.

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

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 10% for the six months ended June 30, 2023, compared with 7% of product sales for the six months ended June 30, 2022. Royalty rates as a percentage of product sales averaged approximately 10% for the second quarter of 2023 compared with 9% of product sales for the second quarter of 2022, and 9% for the first quarter of 2023. 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			Six Months Ended	
	Jun 30 2023	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 15.64**	$ 16.82	$ 17.45	**$ 16.23**	$ 16.10
International average	**$ 51.50**	$ 21.90	$ 53.02	**$ 45.27**	$ 42.96
North Sea	**$ 81.32**	$ —	$ 84.38	**$ 81.32**	$ 76.28
Offshore Africa	**$ 19.44**	$ 21.90	$ 15.73	**$ 20.32**	$ 14.40
Crude oil and NGLs average	**$ 18.38**	$ 16.93	$ 19.58	**$ 17.67**	$ 17.67
Natural gas ($/Mcf) (1)					
North America	**$ 1.35**	$ 1.43	$ 1.15	**$ 1.39**	$ 1.21
International average	**$ 4.83**	$ 8.08	$ 4.12	**$ 6.39**	$ 4.38
North Sea	**$ 9.17**	$ 10.80	$ 6.60	**$ 10.15**	$ 7.56
Offshore Africa	**$ 4.17**	$ 7.35	$ 3.78	**$ 5.63**	$ 3.86
Natural gas average	**$ 1.37**	$ 1.47	$ 1.17	**$ 1.42**	$ 1.24
Average ($/BOE) (1)	**$ 14.24**	$ 13.51	$ 14.44	**$ 13.88**	$ 13.57

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

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2023 averaged $16.23 per bbl, comparable with $16.10 per bbl for the six months ended June 30, 2022. North America crude oil and NGLs production expense for the second quarter of 2023 of $15.64 per bbl decreased 10% from $17.45 per bbl for the second quarter of 2022, and decreased 7% from $16.82 per bbl for the first quarter of 2023. The decrease in crude oil and NGLs production expense per bbl for the second quarter of 2023 from the second quarter of 2022 primarily reflected lower natural gas fuel costs, partially offset by the impact of higher service and power costs, and the impact of wildfires and a third-party pipeline outage on production volumes. The decrease in crude oil and NGLs production expense per bbl for the second quarter of 2023 from the first quarter of 2023 primarily reflected lower natural gas fuel costs, partially offset by the impact of wildfires and a third-party pipeline outage.

North America natural gas production expense averaged $1.39 per Mcf for the six months ended June 30, 2023, an increase of 15% from $1.21 per Mcf for the six months ended June 30, 2022. North America natural gas production expense for the second quarter of 2023 averaged $1.35 per Mcf, an increase of 17% from $1.15 per Mcf for the second quarter of 2022, and a decrease of 6% from $1.43 per Mcf for the first quarter of 2023. The increase in natural gas production expense per Mcf for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected higher service and power costs, and the impact of wildfires and a third-party pipeline outage on production volumes. The decrease in natural gas production expense per Mcf for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of seasonal weather conditions, partially offset by the impact of wildfires and a third-party pipeline outage.

International

International crude oil and NGLs production expense for the six months ended June 30, 2023 averaged $45.27 per bbl, an increase of 5% from $42.96 per bbl for the six months ended June 30, 2022. International crude oil and NGLs production expense for the second quarter of 2023 of $51.50 per bbl decreased 3% from $53.02 per bbl for the second quarter of 2022, and increased 135% from $21.90 per bbl for the first quarter of 2023. The fluctuations in crude oil and NGLs production expense per bbl for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected the timing of liftings from various fields that have different cost structures, lower energy costs in 2023, and fluctuations in foreign exchange. The increase in international crude oil and NGLs production expense per bbl for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of no crude oil liftings from the Company's platforms in the North Sea in the first quarter.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
North America	**$ 871**	$ 890	$ 855	**$ 1,761**	$ 1,733
North Sea	**15**	1	50	**16**	79
Offshore Africa	**65**	35	42	**100**	93
Depletion, depreciation and amortization	**$ 951**	$ 926	$ 947	**$ 1,877**	$ 1,905
$/BOE (1)	**$ 12.26**	$ 12.14	$ 12.14	**$ 12.20**	$ 12.27

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

Depletion, depreciation and amortization expense for the six months ended June 30, 2023 of $12.20 per BOE was comparable with $12.27 per BOE for the six months ended June 30, 2022. Depletion, depreciation and amortization expense for the second quarter of 2023 of $12.26 per BOE was comparable with $12.14 per BOE for the second quarter of 2022 and $12.14 per BOE for the first quarter of 2023.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
North America	**$ 58**	$ 59	$ 35	**$ 117**	$ 70
North Sea	**12**	11	6	**23**	13
Offshore Africa	**2**	2	1	**4**	3
Asset retirement obligation accretion	**$ 72**	$ 72	$ 42	**$ 144**	$ 86
$/BOE (1)	**$ 0.93**	$ 0.94	$ 0.55	**$ 0.93**	$ 0.55

(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 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 expense for the six months ended June 30, 2023 of $0.93 per BOE increased 69% from $0.55 per BOE for the six months ended June 30, 2022. Asset retirement obligation accretion expense for the second quarter of 2023 of $0.93 per BOE increased 69% from $0.55 per BOE for the second quarter of 2022 and was comparable with $0.94 per BOE for the first quarter of 2023. The increase in asset retirement obligation accretion expense per BOE for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected the impact of cost estimate and discount rate revisions made to the asset retirement obligation during 2022.

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 355,246 bbl/d in the second quarter of 2023, primarily reflecting the completion of planned turnaround activities at Horizon and Scotford during the quarter.

The Company incurred production expense of $997 million for the second quarter of 2023, a decrease of 7% from $1,077 million for the second quarter of 2022, and a decrease of 4% from $1,042 million for the first quarter of 2023. The decrease from the comparable periods primarily reflected lower natural gas costs, partially offset by higher service costs.

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

	Three Months Ended			Six Months Ended	
($/bbl)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Realized SCO sales price (1)	**$ 95.08**	$ 96.07	$ 137.60	**$ 95.64**	$ 123.42
Bitumen value for royalty purposes (2)	**$ 66.51**	$ 47.73	$ 110.96	**$ 56.10**	$ 97.58
Bitumen royalties (3)	**$ 13.58**	$ 10.04	$ 31.63	**$ 11.58**	$ 21.58
Transportation (1)	**$ 2.03**	$ 1.52	$ 2.05	**$ 1.74**	$ 1.77

(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 $95.64 per bbl for the six months ended June 30, 2023, a decrease of 23% from $123.42 per bbl for the six months ended June 30, 2022. The realized SCO sales price averaged $95.08 per bbl for the second quarter of 2023, a decrease of 31% from $137.60 per bbl for the second quarter of 2022, and comparable with $96.07 per bbl for the first quarter of 2023. The decrease in the realized SCO sales price for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected the decrease in WTI benchmark pricing.

The decrease in bitumen royalties per bbl for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected the impact of lower prevailing bitumen pricing combined with sliding scale royalty rates. The increase for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of higher prevailing bitumen pricing.

Transportation expense averaged $1.74 per bbl for the six months ended June 30, 2023, comparable with $1.77 per bbl for the six months ended June 30, 2022. Transportation expense averaged $2.03 per bbl for the second quarter of 2023, comparable with $2.05 per bbl for the second quarter of 2022, and an increase of 34% from $1.52 per bbl for the first quarter of 2023. The increase in transportation expense per bbl for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of lower sales volumes and higher sales to the US Gulf Coast in the second quarter.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production expense disclosed in note 17 to the financial statements.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Production expense, excluding natural gas costs	**$ 957**	$ 971	$ 979	**$ 1,928**	$ 1,875
Natural gas costs	**40**	71	98	**111**	179
Production expense	**$ 997**	$ 1,042	$ 1,077	**$ 2,039**	$ 2,054

($/bbl)	Three Months Ended Jun 30 2023	Mar 31 2023	Jun 30 2022	Six Months Ended Jun 30 2023	Jun 30 2022
Production expense, excluding natural gas costs (1)	**$ 30.03**	$ 23.35	$ 30.69	**$ 26.25**	$ 26.19
Natural gas costs (2)	**1.25**	1.71	3.07	**1.51**	2.49
Production expense (3)	**$ 31.28**	$ 25.06	$ 33.76	**$ 27.76**	$ 28.68
Sales volumes (bbl/d)	**350,041**	462,021	350,500	**405,721**	395,661

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

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

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

Production expense for the six months ended June 30, 2023 of $27.76 per bbl decreased 3% from $28.68 per bbl for the six months ended June 30, 2022. Production expense for the second quarter of 2023 averaged $31.28 per bbl, a decrease of 7% from $33.76 per bbl for the second quarter of 2022, and an increase of 25% from $25.06 per bbl for the first quarter of 2023. The decrease in production expense per bbl for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected lower natural gas fuel costs, partially offset by higher service costs. The increase in production expense per bbl for the second quarter of 2023 from the first quarter of 2023 primarily reflected lower sales volumes in the second quarter.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Jun 30 2023	Mar 31 2023	Jun 30 2022	Six Months Ended Jun 30 2023	Jun 30 2022
Depletion, depreciation and amortization	**$ 442**	$ 488	$ 412	**$ 930**	$ 857
$/bbl (1)	**$ 13.88**	$ 11.74	$ 12.92	**$ 12.67**	$ 11.97

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

Depletion, depreciation and amortization expense for the six months ended June 30, 2023 of $12.67 per bbl increased 6% from $11.97 per bbl for the six months ended June 30, 2022. Depletion, depreciation and amortization expense for the second quarter of 2023 of $13.88 per bbl increased 7% from $12.92 per bbl for the second quarter of 2022, and increased 18% from $11.74 per bbl for the first quarter of 2023. The increase in depletion, depreciation and amortization expense on a per barrel basis for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected the impact of derecognitions in the second quarter of 2023, as well as higher depreciation on lease assets. The increase in depletion, depreciation and amortization expense on a per barrel basis for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of lower sales volumes and derecognitions in the second quarter.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Jun 30 2023	Mar 31 2023	Jun 30 2022	Six Months Ended Jun 30 2023	Jun 30 2022
Asset retirement obligation accretion	**$ 19**	$ 20	$ 16	**$ 39**	$ 31
$/bbl (1)	**$ 0.62**	$ 0.47	$ 0.48	**$ 0.53**	$ 0.43

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for the six months ended June 30, 2023 of $0.53 per bbl increased 23% from $0.43 per bbl for the six months ended June 30, 2022. Asset retirement obligation accretion expense for the second quarter of 2023 of $0.62 per bbl increased 29% from $0.48 per bbl for the second quarter of 2022, and increased 32% from $0.47 per bbl for the first quarter of 2023. The increase in asset retirement obligation accretion expense on a per barrel basis for the three and six months ended June 30, 2023 from the comparable periods in 2022 primarily reflected the impact of cost estimate and discount rate revisions made to the asset retirement obligation during 2022. The increase in asset retirement obligation accretion expense on a per barrel basis for the second quarter of 2023 from the first quarter of 2023 primarily reflected the impact of lower sales volumes in the second quarter.

MIDSTREAM AND REFINING

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Product sales					
Midstream activities	**$ 15**	$ 21	$ 18	**$ 36**	$ 38
NWRP, refined product sales and other	**203**	250	318	**453**	567
Segmented revenue	**218**	271	336	**489**	605
Less:					
NWRP, refining toll	**85**	70	63	**155**	124
Midstream activities	**6**	8	7	**14**	12
Production expense	**91**	78	70	**169**	136
NWRP, transportation and feedstock costs	**162**	153	244	**315**	423
Depreciation	**4**	4	4	**8**	8
Segmented (loss) earnings	**$ (39)**	$ 36	$ 18	**$ (3)**	$ 38

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 (25% toll payer) of bitumen feedstock for the Company and 37,500 bbl/d (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), 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 second quarter of 2023, production of ultra-low sulphur diesel and other refined products averaged 79,112 BOE/d (19,778 BOE/d to the Company), (three months ended June 30, 2022 – 75,418 BOE/d; 18,855 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at June 30, 2023, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $568 million (December 31, 2022 – $551 million). For the three months ended June 30, 2023, the Company's unrecognized share of the equity loss was $1 million (six months ended June 30, 2023 – unrecognized equity loss of $17 million; three months ended June 30, 2022 – unrecognized equity loss of $15 million; six months ended June 30, 2022 – unrecognized equity loss of $25 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Jun 30 2023**	Three Months Ended Mar 31 2023	Three Months Ended Jun 30 2022	Six Months Ended **Jun 30 2023**	Six Months Ended Jun 30 2022
Administration expense	**$ 119**	$ 106	$ 97	**$ 225**	$ 213
$/BOE (1)	**$ 1.09**	$ 0.90	$ 0.89	**$ 0.99**	$ 0.94
Sales volumes (BOE/d) (2)	**1,202,336**	1,309,942	1,207,485	**1,255,841**	1,253,636

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

(2) Total Company sales volumes.

Administration expense for the six months ended June 30, 2023 of $0.99 per BOE increased 5% from $0.94 per BOE for the six months ended June 30, 2022. Administration expense for the second quarter of 2023 of $1.09 per BOE increased 22% from $0.89 per BOE for the second quarter of 2022, and increased 21% from $0.90 per BOE for the first quarter of 2023. The increase in administration expense per BOE for the three and six months ended June 30, 2023 from the comparable periods was primarily due to higher personnel and corporate costs, partially offset by higher overhead recoveries. The increase in administration expense per BOE for the second quarter of 2023 from the first quarter of 2023 also reflected the impact of lower sales volumes in the second quarter.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Jun 30 2023**	Three Months Ended Mar 31 2023	Three Months Ended Jun 30 2022	Six Months Ended **Jun 30 2023**	Six Months Ended Jun 30 2022
Expense (recovery)	**$ 70**	$ 66	$ (45)	**$ 136**	$ 489

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

The Company recognized $136 million of share-based compensation expense for the six months ended June 30, 2023, 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

	Three Months Ended			Six Months Ended	
($ millions, except effective interest rate)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Interest and other financing expense	**$ 178**	$ 154	$ 160	**$ 332**	$ 323
Less: Interest income and other [1]	**3**	(9)	(6)	**(6)**	(10)
Interest expense on long-term debt and lease liabilities [1]	**$ 175**	$ 163	$ 166	**$ 338**	$ 333
Average current and long-term debt [2]	**$ 12,910**	$ 12,343	$ 14,107	**$ 12,627**	$ 14,529
Average lease liabilities [2]	**1,510**	1,516	1,540	**1,512**	1,545
Average long-term debt and lease liabilities [2]	**$ 14,420**	$ 13,859	$ 15,647	**$ 14,139**	$ 16,074
Average effective interest rate [3] [4]	**4.8%**	4.6%	4.1%	**4.7%**	4.0%
Interest and other financing expense per $/BOE [5]	**$ 1.63**	$ 1.30	$ 1.46	**$ 1.46**	$ 1.43
Sales volumes (BOE/d) [6]	**1,202,336**	1,309,942	1,207,485	**1,255,841**	1,253,636

(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 six months ended June 30, 2023 of $1.46 per BOE was comparable with $1.43 per BOE for the six months ended June 30, 2022. Interest and other financing expense per BOE for the second quarter of 2023 increased 12% to $1.63 per BOE from $1.46 per BOE for the second quarter of 2022, and increased 25% from $1.30 per BOE for the first quarter of 2023. The increase in interest and other financing expense per BOE for the second quarter of 2023 from the comparable periods primarily reflected the impact of higher interest rates on floating rate long-term debt and the impact of lower sales volumes in the second quarter of 2023.

The Company's average effective interest rate for the three and six months ended June 30, 2023 increased from the comparable periods primarily due to higher prevailing interest rates on floating rate long-term debt held during 2023.

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			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Foreign currency contracts	**$ (30)**	$ (2)	$ (19)	**$ (32)**	$ 3
Natural gas financial instruments [1]	**3**	3	17	**6**	22
Crude oil and NGLs financial instruments [1]	**—**	—	9	**—**	14
Net realized (gain) loss	**(27)**	1	7	**(26)**	39
Foreign currency contracts	**2**	3	(1)	**5**	(14)
Natural gas financial instruments [1]	**(6)**	17	(16)	**11**	16
Crude oil and NGLs financial instruments [1]	**—**	—	(4)	**—**	3
Net unrealized (gain) loss	**(4)**	20	(21)	**16**	5
Net (gain) loss	**$ (31)**	$ 21	$ (14)	**$ (10)**	$ 44

(1) Commodity financial instruments were assumed in the acquisition of Storm Resources Ltd. and Painted Pony Energy Ltd. in the fourth quarter of 2021 and 2020, respectively.

During the six months ended June 30, 2023, net realized risk management gains were related to the settlement of foreign currency contracts, partially offset by realized losses on natural gas financial instruments. The Company recorded a net unrealized loss of $16 million ($14 million after-tax of $2 million) on its risk management activities for the six months ended June 30, 2023, including a net unrealized gain of $4 million ($2 million after-tax of $2 million) for the second quarter of 2023 (three months ended March 31, 2023 – unrealized loss of $20 million, $16 million after-tax of $4 million; three months ended June 30, 2022 – unrealized gain of $21 million, $16 million after-tax of $5 million; six months ended June 30, 2022 – unrealized loss of $5 million, $1 million after-tax of $4 million).

Further details related to outstanding derivative financial instruments as at June 30, 2023 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Net realized loss (gain)	**$ 29**	$ (11)	$ (93)	**$ 18**	$ (83)
Net unrealized (gain) loss	**(231)**	(3)	426	**(234)**	270
Net (gain) loss [1]	**$ (202)**	$ (14)	$ 333	**$ (216)**	$ 187

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

The net realized foreign exchange loss for the six months ended June 30, 2023 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the six months ended June 30, 2023 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at June 30, 2023 was US$0.7554 (March 31, 2023 – US$0.7392, June 30, 2022 – US$0.7769).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended **Jun 30 2023**	Mar 31 2023	Jun 30 2022	Six Months Ended **Jun 30 2023**	Jun 30 2022
North America [1]	**$ 299**	$ 480	$ 855	**$ 779**	$ 1,689
North Sea	**(4)**	6	15	**2**	22
Offshore Africa	**20**	10	18	**30**	30
Current PRT – North Sea	**(5)**	(40)	6	**(45)**	(1)
Other taxes	**3**	3	5	**6**	10
Current income tax	**313**	459	899	**772**	1,750
Deferred corporate income tax	**(15)**	23	131	**8**	256
Deferred PRT – North Sea	**11**	7	—	**18**	—
Deferred income tax	**(4)**	30	131	**26**	256
Income tax	**$ 309**	$ 489	$ 1,030	**$ 798**	$ 2,006
Earnings before taxes	**$ 1,772**	$ 2,288	$ 4,532	**$ 4,060**	$ 8,609
Effective tax rate on net earnings [2]	**17%**	21%	23%	**20%**	23%

($ millions, except effective tax rates)	Three Months Ended **Jun 30 2023**	Mar 31 2023	Jun 30 2022	Six Months Ended **Jun 30 2023**	Jun 30 2022
Income tax	**$ 309**	$ 489	$ 1,030	**$ 798**	$ 2,006
Tax effect on non-operating items [3]	**2**	8	(9)	**10**	(1)
Current PRT – North Sea	**5**	40	(6)	**45**	1
Deferred PRT – North Sea	**(11)**	(7)	—	**(18)**	—
Other taxes	**(3)**	(3)	(5)	**(6)**	(10)
Effective tax on adjusted net earnings	**$ 302**	$ 527	$ 1,010	**$ 829**	$ 1,996
Adjusted net earnings from operations [4]	**$ 1,256**	$ 1,881	$ 3,800	**$ 3,137**	$ 7,176
Adjusted net earnings from operations, before taxes	**$ 1,558**	$ 2,408	$ 4,810	**$ 3,966**	$ 9,172
Effective tax rate on adjusted net earnings from operations [5] [6]	**19%**	22%	21%	**21%**	22%

(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 tax effect of PSUs, unrealized risk management, and abandonment expenditure recovery in adjusted net earnings from operations.

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

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

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

The effective tax rate on net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2023 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 corporate income tax and current and deferred PRT in the North Sea for the three and six months ended June 30, 2023 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			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Exploration and Evaluation					
Net expenditures	**$ 9**	$ 28	$ 1	**$ 37**	$ 23
Net property (dispositions) acquisitions	**(2)**	—	1	**(2)**	(2)
Total Exploration and Evaluation	**7**	28	2	**35**	21
Property, Plant and Equipment					
Net property acquisitions	**17**	—	30	**17**	512
Well drilling, completion and equipping	**443**	510	384	**953**	728
Production and related facilities	**354**	361	293	**715**	504
Other	**19**	11	16	**30**	29
Total Property, Plant and Equipment	**833**	882	723	**1,715**	1,773
Total Exploration and Production	**840**	910	725	**1,750**	1,794
Oil Sands Mining and Upgrading					
Project costs	**106**	52	74	**158**	119
Sustaining capital	**480**	261	375	**741**	581
Turnaround costs	**132**	22	193	**154**	253
Other	**1**	1	2	**2**	3
Total Oil Sands Mining and Upgrading	**719**	336	644	**1,055**	956
Midstream and Refining	**2**	3	3	**5**	5
Head office	**8**	8	8	**16**	13
Abandonment expenditures, net (2)	**100**	137	70	**237**	137
Net capital expenditures	**$ 1,669**	$ 1,394	$ 1,450	**$ 3,063**	$ 2,905
By Segment					
North America	**$ 778**	$ 884	$ 675	**$ 1,662**	$ 1,720
North Sea	**5**	3	27	**8**	38
Offshore Africa	**57**	23	23	**80**	36
Oil Sands Mining and Upgrading	**719**	336	644	**1,055**	956
Midstream and Refining	**2**	3	3	**5**	5
Head office	**8**	8	8	**16**	13
Abandonment expenditures, net (2)	**100**	137	70	**237**	137
Net capital expenditures	**$ 1,669**	$ 1,394	$ 1,450	**$ 3,063**	$ 2,905

(1) Net capital expenditures exclude the impact of lease assets and fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

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

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

Net capital expenditures for the six months ended June 30, 2023 were $3,063 million compared with $2,905 million for the six months ended June 30, 2022. Net capital expenditures for the six months ended June 30, 2023 included base capital expenditures (1) of $2,502 million and strategic growth capital expenditures (1) of $546 million, in accordance with the Company's capital budget.

2023 Capital Budget

On November 30, 2022, the Company announced its 2023 base capital budget (2) targeted at approximately $4,190 million. The budget also includes incremental strategic growth capital of approximately $1,020 million that targets to add additional production and capacity growth beyond 2023 in the Company's Exploration and Production segments, and long life low decline thermal in situ and Oil Sands Mining and Upgrading assets.

The 2023 capital budget in Oil Sands Mining and Upgrading and North America E&P has increased by a combined $200 million compared to the original budget. Oil Sands Mining and Upgrading has increased by approximately $130 million primarily reflecting increased third-party service costs and scope changes relating to sustaining activities to ensure safe and effective operations. The remaining approximately $70 million relates to North America E&P and thermal operations largely as a result of increased non-operated and workover activity as well as inflationary pressures. The Company's 2023 targeted total capital program has increased by 4% to approximately $5,400 million.

The 2023 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Drilling Activity (1) (2)

	Three Months Ended			Six Months Ended	
(number of net wells)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Net successful crude oil wells (3)	**52**	83	83	**135**	139
Net successful natural gas wells	**21**	21	20	**42**	43
Dry wells	**—**	2	1	**2**	1
Total	**73**	106	104	**179**	183
Success rate	**100%**	98%	99%	**99%**	99%

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

(2) In addition, during the second quarter of 2023, on a net basis, the Company drilled 15 service wells in the Company's thermal oil projects. During the six months ended June 30, 2023, on a net basis, the Company drilled 334 stratigraphic and 7 service wells in the Oil Sands Mining and Upgrading segment, 24 stratigraphic and 42 service wells in the Company's thermal oil projects, and 2 service wells in the Northern Plains region.

(3) Includes bitumen wells.

North America

During the second quarter of 2023, the Company drilled 21 net natural gas wells, 24 net primary heavy crude oil wells, 23 net bitumen (thermal oil) wells and 5 net light crude oil wells.

(1) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for more details on net capital expenditures.

(2) 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 this MD&A for more details on net capital expenditures.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2023**	Mar 31 2023	Dec 31 2022	Jun 30 2022
Adjusted working capital [(1)]	**$ (293)**	$ (307)	$ (1,190)	$ (99)
Long-term debt, net [(2)]	**$ 12,033**	$ 11,932	$ 10,525	$ 12,369
Shareholders' equity	**$ 38,644**	$ 38,585	$ 38,175	$ 39,340
Debt to book capitalization [(2)]	**23.7%**	23.6%	21.6%	23.9%
After-tax return on average capital employed [(3)]	**15.8%**	19.7%	22.1%	22.7%

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

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

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

As at June 30, 2023, 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 is 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, 2022. 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 maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2023, the Company extended its revolving syndicated credit facility originally maturing June 2024 to June 2027.
  - Borrowings under the Company's revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, 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.
  - As at June 30, 2023, the Company had $3,000 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of medium-term notes in Canada. Subsequent to June 30, 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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

- As at June 30, 2023, the Company had US$3,000 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of debt securities in the United States. Subsequent to June 30, 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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

As at June 30, 2023, the Company had undrawn revolving bank credit facilities of $4,954 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,600 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At June 30, 2023, the Company had $437 million 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 $12,033 million as at June 30, 2023, resulting in a debt to book capitalization ratio (1) of 23.7% (December 31, 2022 – 21.6%); this ratio was below the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at June 30, 2023 are discussed in note 8 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 June 30, 2023, the Company was in compliance with this covenant.

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 June 30, 2023, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt (1)	$ 2,319	$ 794	$ 3,115	$ 5,993
Other long-term liabilities (2)	$ 232	$ 167	$ 436	$ 694
Interest and other financing expense (3)	$ 629	$ 566	$ 1,386	$ 3,540

(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, $227 million; one to less than two years, $167 million; two to less than five years, $436 million; and thereafter, $694 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 June 30, 2023.

Share Capital

As at June 30, 2023, there were 1,092,260,000 common shares outstanding (December 31, 2022 – 1,102,636,000 common shares) and 30,942,000 stock options outstanding (December 31, 2022 - 31,150,000). As at August 1, 2023, the Company had 1,090,578,000 common shares outstanding and 30,229,000 stock options outstanding.

On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.90 per common share, beginning with the dividend paid on April 5, 2023. On November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share. On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share. On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, from $0.5875 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

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

On March 8, 2023, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 92,296,006 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2023 and ending March 12, 2024.

For the six months ended June 30, 2023, the Company purchased 15,300,000 common shares at a weighted average price of $76.80 per common share for a total cost of $1,175 million. Retained earnings were reduced by $1,029 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2023, up to and including August 1, 2023, the Company purchased 2,200,000 common shares at a weighted average price of $76.52 per common share for a total cost of $168 million.

Since the acquisition of AOSP during the second quarter of 2017, shareholder returns through share repurchases have resulted in a net reduction of approximately 122,696,000 outstanding common shares. As part of the acquisition, the Company issued 97,560,975 shares, resulting in shares outstanding at May 31, 2017 of approximately 1,214,956,000. At June 30, 2023, there were 1,092,260,000 shares outstanding, lower than pre-AOSP levels.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at June 30, 2023:

($ millions)		Remaining 2023		2024		2025		2026		2027		Thereafter
Product transportation and processing (1)	$	594	$	1,394	$	1,262	$	1,157	$	1,106	$	11,337
North West Redwater Partnership service toll (2)	$	77	$	157	$	155	$	138	$	124	$	5,055
Offshore vessels and equipment	$	19	$	34	$	—	$	—	$	—	$	—
Field equipment and power	$	21	$	28	$	26	$	23	$	22	$	215
Other	$	12	$	24	$	23	$	17	$	—	$	—

(1) The Company's commitment for the 20-year product transportation agreement on the Trans Mountain Pipeline Expansion ("TMX") is subject to change pending approval of the interim toll filing by the Canada Energy Regulator.

(2) 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 $3,001 million of interest payable over the 40-year tolling period, ending in 2058.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS 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, 2022.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the six months ended June 30, 2023 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 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 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. 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			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Net earnings	**$ 1,463**	$ 1,799	$ 3,502	**$ 3,262**	$ 6,603
Share-based compensation, net of tax (1)	**66**	62	(47)	**128**	479
Unrealized risk management (gain) loss, net of tax (2)	**(2)**	16	(16)	**14**	1
Unrealized foreign exchange (gain) loss, net of tax (3)	**(231)**	(3)	426	**(234)**	270
Realized foreign exchange gain on settlement of cross currency swap, net of tax (4)	**—**	—	(69)	**—**	(69)
(Gain) loss from investments, net of tax (5)	**(40)**	7	25	**(33)**	(58)
Other, net of tax (6)	**—**	—	(21)	**—**	(50)
Non-operating items, net of tax	**(207)**	82	298	**(125)**	573
Adjusted net earnings from operations	**$ 1,256**	$ 1,881	$ 3,800	**$ 3,137**	$ 7,176

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for the three months ended June 30, 2023 was an expense of $70 million (three months ended March 31, 2023 – $66 million expense, three months ended June 30, 2022 – $45 million recovery; six months ended June 30, 2023 – $136 million expense, six months ended June 30, 2022 – $489 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 gain for the three months ended June 30, 2023 was $4 million (three months ended March 31, 2023 – $20 million loss, three months ended June 30, 2022 – $21 million gain; six months ended June 30, 2023 – $16 million loss, six months ended June 30, 2022 – $5 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, partially offset by the impact of cross currency swaps, 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 2022, the Company settled the US$550 million cross currency swap designated as a cash flow hedge of a portion of the US$1,100 million 6.25% US dollar debt securities due March 2038. The Company realized cash proceeds of $158 million on settlement. Pre- and after-tax amounts for the realized foreign exchange gain on settlement of the swap are the same.

(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. There is zero net tax impact on these gains and losses from investments.

(6) Other relates to the impact of government grant income under the provincial well-site rehabilitation programs. Pre-tax other for the three months ended June 30, 2023 was $nil (three months ended March 31, 2023 – $nil, three months ended June 30, 2022 – $27 million; six months ended June 30, 2023 – $nil, six months ended June 30, 2022 – $65 million).

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 excluding the impact of government grant income under the provincial well-site rehabilitation programs, 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 and to repay debt. A reconciliation for adjusted funds flow, from cash flows from operating activities is presented below.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Cash flows from operating activities	**$ 2,745**	$ 1,295	$ 5,896	**$ 4,040**	$ 8,749
Net change in non-cash working capital	**(17)**	1,908	(478)	**1,891**	1,462
Abandonment expenditures, net (1)	**100**	137	70	**237**	137
Movements in other long-term assets (2)	**(86)**	89	(56)	**3**	59
Adjusted funds flow	**$ 2,742**	$ 3,429	$ 5,432	**$ 6,171**	$ 10,407

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section below.

(2) Includes the unamortized cost of the share bonus program.

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

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

Abandonment Expenditures, net

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's annual capital budget. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's consolidated Statements of Cash Flows, adjusted for the impact of government grant income under the provincial well-site rehabilitation programs. A reconciliation of abandonment expenditures, net is presented below.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Abandonment expenditures	**$ 100**	$ 137	$ 97	**$ 237**	$ 202
Government grants for abandonment expenditures	**—**	—	(27)	**—**	(65)
Abandonment expenditures, net	**$ 100**	$ 137	$ 70	**$ 237**	$ 137

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 17 to the financial statements.

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

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales include 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			Six Months Ended	
($ millions, except bbl/d and $/bbl)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs (bbl/d)					
North America	**466,284**	481,045	475,744	**473,623**	485,224
International					
North Sea	**19,991**	—	16,530	**10,051**	13,902
Offshore Africa	**18,603**	10,393	13,902	**14,521**	16,214
Total International	**38,594**	10,393	30,432	**24,572**	30,116
Total sales volumes	**504,878**	491,438	506,176	**498,195**	515,340
Crude oil and NGLs sales (1)	**$ 4,405**	$ 3,841	$ 6,871	**$ 8,246**	$ 12,754
Less: Blending and feedstock costs (2)	**1,094**	1,238	1,561	**2,332**	3,027
Realized crude oil and NGLs sales	**$ 3,311**	$ 2,603	$ 5,310	**$ 5,914**	$ 9,727
Realized price ($/bbl)	**$ 72.06**	$ 58.85	$ 115.26	**$ 65.58**	$ 104.27

(1) Crude oil and NGLs sales in note 17 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			Six Months Ended	
($ millions, except BOE/d and $/BOE)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Barrels of oil equivalent (BOE/d)					
North America	**811,590**	835,542	823,931	**823,500**	825,040
International					
North Sea	**20,269**	419	16,845	**10,399**	14,296
Offshore Africa	**20,436**	11,961	16,210	**16,221**	18,639
Total International	**40,705**	12,380	33,055	**26,620**	32,935
Total sales volumes	**852,295**	847,922	856,986	**850,120**	857,975
Barrels of oil equivalent sales (1)	**$ 4,884**	$ 4,663	$ 8,388	**$ 9,547**	$ 15,220
Less: Blending and feedstock costs (2)	**1,094**	1,238	1,561	**2,332**	3,027
Less: Sulphur income	**(5)**	(8)	(41)	**(13)**	(60)
Realized barrels of oil equivalent sales	**$ 3,795**	$ 3,433	$ 6,868	**$ 7,228**	$ 12,253
Realized price ($/BOE)	**$ 48.94**	$ 44.98	$ 88.07	**$ 46.98**	$ 78.91

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

(2) Blending and feedstock costs 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			Six Months Ended	
($ millions, except $ per unit amounts)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Transportation, blending and feedstock [1]	**$ 1,413**	$ 1,546	$ 1,849	**$ 2,959**	$ 3,603
Less: Blending and feedstock costs	**1,094**	1,238	1,561	**2,332**	3,027
Transportation	**$ 319**	$ 308	$ 288	**$ 627**	$ 576
Transportation ($/BOE)	**$ 4.11**	$ 4.03	$ 3.70	**$ 4.08**	$ 3.72
Amounts attributed to crude oil and NGLs	**$ 210**	$ 200	$ 190	**$ 410**	$ 387
Transportation ($/bbl)	**$ 4.57**	$ 4.52	$ 4.13	**$ 4.54**	$ 4.16
Amounts attributed to natural gas	**$ 109**	$ 108	$ 98	**$ 217**	$ 189
Transportation ($/Mcf)	**$ 0.58**	$ 0.55	$ 0.52	**$ 0.57**	$ 0.50

(1) Transportation, blending and feedstock in note 17 to the financial statements.

North America – Realized Product Prices and Royalties

Realized crude oil and NGLs price ($/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales include 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			Six Months Ended	
($ millions, except $/bbl and royalty rates)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Crude oil and NGLs sales [1]	**$ 4,040**	$ 3,749	$ 6,470	**$ 7,789**	$ 12,009
Less: Blending and feedstock costs [2]	**1,094**	1,238	1,561	**2,332**	3,027
Realized crude oil and NGLs sales	**$ 2,946**	$ 2,511	$ 4,909	**$ 5,457**	$ 8,982
Realized crude oil and NGLs prices ($/bbl)	**$ 69.44**	$ 57.99	$ 113.37	**$ 63.66**	$ 102.25
Crude oil and NGLs royalties [3]	**$ 491**	$ 437	$ 1,136	**$ 928**	$ 1,966
Crude oil and NGLs royalty rates	**17%**	17%	23%	**17%**	22%

(1) Crude oil and NGLs sales in note 17 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 17 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) including 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			Six Months Ended	
($ millions, except for bbl/d and $/bbl)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
SCO sales volumes (bbl/d)	**350,041**	462,021	350,500	**405,721**	395,661
Crude oil and NGLs sales (1)	**$ 3,546**	$ 4,482	$ 4,962	**$ 8,028**	$ 9,813
Less: Blending and feedstock costs	**517**	487	573	**1,004**	974
Realized SCO sales	**$ 3,029**	$ 3,995	$ 4,389	**$ 7,024**	$ 8,839
Realized SCO sales price ($/bbl)	**$ 95.08**	$ 96.07	$ 137.60	**$ 95.64**	$ 123.42
Transportation, blending and feedstock (2)	**$ 582**	$ 550	$ 638	**$ 1,132**	$ 1,101
Less: Blending and feedstock costs	**517**	487	573	**1,004**	974
Transportation	**$ 65**	$ 63	$ 65	**$ 128**	$ 127
Transportation ($/bbl)	**$ 2.03**	$ 1.52	$ 2.05	**$ 1.74**	$ 1.77

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

(2) Transportation, blending and feedstock in note 17 to the financial statements.

Net Capital Expenditures

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, and abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs. 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			Six Months Ended	
($ millions)	**Jun 30 2023**	Mar 31 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Cash flows used in investing activities	**$ 1,560**	$ 1,153	$ 1,345	**$ 2,713**	$ 2,596
Net change in non-cash working capital	**9**	104	35	**113**	172
Capital expenditures	**1,569**	1,257	1,380	**2,826**	2,768
Abandonment expenditures, net (1)	**100**	137	70	**237**	137
Net capital expenditures (2)	**$ 1,669**	$ 1,394	$ 1,450	**$ 3,063**	$ 2,905

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section above.

(2) For the six months ended June 30, 2023 includes base capital expenditures of $2,502 million, and strategic growth capital expenditures of $546 million. Strategic growth capital expenditures represent the allocation of the Company's free cash flow that will be directed to strategic capital growth opportunities that target to increase production volumes in future periods and that exceed the Company's base capital expenditures for the current fiscal year, as outlined in the Company's capital budget.

Liquidity

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

($ millions)	**Jun 30 2023**	Mar 31 2023	Dec 31 2022	Jun 30 2022
Undrawn bank credit facilities	**$ 4,954**	$ 5,520	$ 5,520	$ 5,520
Cash and cash equivalents	**122**	92	920	233
Investments	**524**	484	491	367
Liquidity	**$ 5,600**	$ 6,096	$ 6,931	$ 6,120

Long-term Debt, net

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

Debt to Book Capitalization

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

After-Tax Return on Average Capital Employed

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

($ millions, except ratios)	**Jun 30 2023**	Mar 31 2023	Dec 31 2022	Jun 30 2022
Interest adjusted after-tax return:				
Net earnings, 12 months trailing	**$ 7,596**	$ 9,635	$ 10,937	$ 11,339
Interest and other financing expense, net of tax, 12 months trailing (1)	**431**	417	424	517
Interest adjusted after-tax return	**$ 8,027**	$ 10,052	$ 11,361	$ 11,856
12 months average current portion long-term debt (2)	**$ 1,274**	$ 1,357	$ 1,359	$ 1,664
12 months average long-term debt (2)	**10,961**	11,228	11,761	13,597
12 months average common shareholders' equity (2)	**38,577**	38,544	38,218	36,902
12 months average capital employed	**$ 50,812**	$ 51,129	$ 51,338	$ 52,163
After-tax return on average capital employed	**15.8%**	19.7%	22.1%	22.7%

(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		**Jun 30 2023**		Dec 31 2022
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**122**	$	920
Accounts receivable			**2,790**		3,555
Inventory			**1,966**		1,815
Prepaids and other			**508**		215
Investments	6		**524**		491
Current portion of other long-term assets	7		**47**		61
			5,957		7,057
Exploration and evaluation assets	3		**2,233**		2,226
Property, plant and equipment	4		**64,975**		64,859
Lease assets	5		**1,431**		1,447
Other long-term assets	7		**563**		553
		$	**75,159**	$	76,142
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**1,120**	$	1,341
Accrued liabilities			**3,860**		4,209
Current income taxes payable			**—**		1,324
Current portion of long-term debt	8		**2,319**		404
Current portion of other long-term liabilities	5,9		**1,270**		1,373
			8,569		8,651
Long-term debt	8		**9,836**		11,041
Other long-term liabilities	5,9		**7,960**		8,161
Deferred income taxes			**10,150**		10,114
			36,515		37,967
SHAREHOLDERS' EQUITY					
Share capital	11		**10,534**		10,294
Retained earnings			**27,933**		27,672
Accumulated other comprehensive income	12		**177**		209
			38,644		38,175
		$	**75,159**	$	76,142

Commitments and contingencies (note 16)

Approved by the Board of Directors on August 2, 2023.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Jun 30 2023**	Three Months Ended Jun 30 2022	Six Months Ended **Jun 30 2023**	Six Months Ended Jun 30 2022
Product sales	17	**$ 8,846**	$ 13,812	**$ 18,394**	$ 25,944
Less: royalties		**(956)**	(2,337)	**(1,874)**	(3,792)
Revenue		**7,890**	11,475	**16,520**	22,152
Expenses					
Production		**2,211**	2,287	**4,375**	4,327
Transportation, blending and feedstock		**2,330**	2,682	**4,664**	5,137
Depletion, depreciation and amortization	4,5	**1,397**	1,363	**2,815**	2,770
Administration		**119**	97	**225**	213
Share-based compensation	9	**70**	(45)	**136**	489
Asset retirement obligation accretion	9	**91**	58	**183**	117
Interest and other financing expense		**178**	160	**332**	323
Risk management activities	15	**(31)**	(14)	**(10)**	44
Foreign exchange (gain) loss		**(202)**	333	**(216)**	187
(Gain) loss from investments	6	**(45)**	22	**(44)**	(64)
		6,118	6,943	**12,460**	13,543
Earnings before taxes		**1,772**	4,532	**4,060**	8,609
Current income tax expense	10	**313**	899	**772**	1,750
Deferred income tax (recovery) expense	10	**(4)**	131	**26**	256
Net earnings		**$ 1,463**	$ 3,502	**$ 3,262**	$ 6,603
Net earnings per common share					
Basic	14	**$ 1.34**	$ 3.04	**$ 2.97**	$ 5.70
Diluted	14	**$ 1.32**	$ 3.00	**$ 2.94**	$ 5.63

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2023**	Three Months Ended Jun 30 2022	Six Months Ended **Jun 30 2023**	Six Months Ended Jun 30 2022
Net earnings	**$ 1,463**	$ 3,502	**$ 3,262**	$ 6,603
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 (2022 – $nil) – three months ended; $nil (2022 – $1 million) – six months ended	**1**	1	**1**	4
Reclassification to net earnings, net of taxes of $nil (2022 – $nil) – three months ended; $nil (2022 – $1 million) – six months ended	**(1)**	(1)	**(2)**	(4)
	—	—	**(1)**	—
Foreign currency translation adjustment				
Translation of net investment	**(30)**	85	**(31)**	48
Other comprehensive (loss) income, net of taxes	**(30)**	85	**(32)**	48
Comprehensive income	**$ 1,433**	$ 3,587	**$ 3,230**	$ 6,651

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended Jun 30 2023	Jun 30 2022
Share capital	11		
Balance – beginning of period		**$ 10,294**	$ 10,168
Issued upon exercise of stock options		**190**	309
Previously recognized liability on stock options exercised for common shares		**196**	253
Purchase of common shares under Normal Course Issuer Bid		**(146)**	(380)
Balance – end of period		**10,534**	10,350
Retained earnings			
Balance – beginning of period		**27,672**	26,778
Net earnings		**3,262**	6,603
Dividends on common shares	11	**(1,972)**	(1,730)
Purchase of common shares under Normal Course Issuer Bid	11	**(1,029)**	(2,708)
Balance – end of period		**27,933**	28,943
Accumulated other comprehensive income (loss)	12		
Balance – beginning of period		**209**	(1)
Other comprehensive (loss) income, net of taxes		**(32)**	48
Balance – end of period		**177**	47
Shareholders' equity		**$ 38,644**	$ 39,340

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Jun 30 2023**	Three Months Ended Jun 30 2022	Six Months Ended **Jun 30 2023**	Six Months Ended Jun 30 2022
Operating activities					
Net earnings		**$ 1,463**	$ 3,502	**$ 3,262**	$ 6,603
Non-cash items					
Depletion, depreciation and amortization		**1,397**	1,363	**2,815**	2,770
Share-based compensation		**70**	(45)	**136**	489
Asset retirement obligation accretion		**91**	58	**183**	117
Unrealized risk management (gain) loss		**(4)**	(21)	**16**	5
Unrealized foreign exchange (gain) loss		**(231)**	426	**(234)**	270
(Gain) loss from investments	6	**(40)**	25	**(33)**	(58)
Deferred income tax (recovery) expense		**(4)**	131	**26**	256
Realized foreign exchange gain on settlement of cross currency swap		**—**	(69)	**—**	(69)
Proceeds on settlement of cross currency swap		**—**	89	**—**	89
Other		**86**	56	**(3)**	(59)
Abandonment expenditures	9	**(100)**	(97)	**(237)**	(202)
Net change in non-cash working capital		**17**	478	**(1,891)**	(1,462)
Cash flows from operating activities		**2,745**	5,896	**4,040**	8,749
Financing activities					
Issue (repayment) of bank credit facilities and commercial paper, net	8	**345**	(1,504)	**933**	(1,156)
Repayment of medium-term notes	8	**—**	(139)	**(11)**	(1,139)
Proceeds on settlement of cross currency swap		**—**	69	**—**	69
Payment of lease liabilities	5,9	**(68)**	(50)	**(135)**	(99)
Issue of common shares on exercise of stock options	11	**47**	57	**190**	309
Dividends on common shares		**(989)**	(871)	**(1,927)**	(1,560)
Purchase of common shares under Normal Course Issuer Bid	11	**(490)**	(2,005)	**(1,175)**	(3,088)
Cash flows used in financing activities		**(1,155)**	(4,443)	**(2,125)**	(6,664)
Investing activities					
Net expenditures on exploration and evaluation assets	3,17	**(7)**	(2)	**(35)**	(21)
Net expenditures on property, plant and equipment	4,17	**(1,562)**	(1,378)	**(2,791)**	(2,747)
Net change in non-cash working capital		**9**	35	**113**	172
Cash flows used in investing activities		**(1,560)**	(1,345)	**(2,713)**	(2,596)
Increase (decrease) in cash and cash equivalents		**30**	108	**(798)**	(511)
Cash and cash equivalents – beginning of period		**92**	125	**920**	744
Cash and cash equivalents – end of period		**$ 122**	$ 233	**$ 122**	$ 233
Interest paid on long-term debt, net		**$ 135**	$ 119	**$ 303**	$ 303
Income taxes paid, net		**$ 651**	$ 411	**$ 2,207**	$ 2,170

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 and South Africa 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, 2022, 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, 2022.

Critical Accounting Estimates and Judgements

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

2. CHANGE IN ACCOUNTING POLICIES

In May 2023, the IASB issued amendments to IAS 12 "Income Taxes" related to the accounting for deferred taxes arising in those jurisdictions implementing the Organization for Economic Co-operation and Development's Pillar Two model rules ("Pillar Two Legislation"). The amendments were effective immediately and adopted in the second quarter of 2023 and did not have a significant impact on the Company's interim consolidated financial statements.

In May 2021, the IASB issued amendments to IAS 12 "Income Taxes" to require companies to recognize deferred tax on particular transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences. The amendments were adopted on January 1, 2023 and did not have a significant impact on the Company's interim consolidated financial statements.

In February 2021, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to require companies to disclose their material accounting policy information rather than their significant accounting policies. To support this amendment the IASB also amended IFRS Practice Statement 2 "Making Materiality Judgements". The amendments were adopted on January 1, 2023 and did not have a significant impact on the Company's interim consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2022	$ 2,026	$ —	$ 98	$ 102	$ 2,226
Additions	**34**	**—**	**1**	**—**	**35**
Transfers to property, plant and equipment	**(26)**	**—**	**—**	**—**	**(26)**
Foreign exchange adjustments	**—**	**—**	**(2)**	**—**	**(2)**
At June 30, 2023	**$ 2,034**	**$ —**	**$ 97**	**$ 102**	**$ 2,233**

4. 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, 2022	$ 81,075	$ 8,258	$ 4,332	$ 47,732	$ 474	$ 536	$ 142,407
Additions / Acquisitions	**1,641**	**8**	**79**	**1,055**	**5**	**16**	**2,804**
Transfers from exploration & evaluation assets	**26**	**—**	**—**	**—**	**—**	**—**	**26**
Derecognitions (1)	**(307)**	**—**	**—**	**(185)**	**—**	**—**	**(492)**
Foreign exchange adjustments and other	**—**	**(181)**	**(97)**	**—**	**—**	**—**	**(278)**
At June 30, 2023	**$ 82,435**	**$ 8,085**	**$ 4,314**	**$ 48,602**	**$ 479**	**$ 552**	**$ 144,467**
Accumulated depletion and depreciation							
At December 31, 2022	$ 55,835	$ 8,106	$ 3,277	$ 9,712	$ 198	$ 420	$ 77,548
Expense	**1,716**	**8**	**84**	**854**	**8**	**12**	**2,682**
Derecognitions (1)	**(307)**	**—**	**—**	**(185)**	**—**	**—**	**(492)**
Foreign exchange adjustments and other	**(5)**	**(170)**	**(74)**	**3**	**—**	**—**	**(246)**
At June 30, 2023	**$ 57,239**	**$ 7,944**	**$ 3,287**	**$ 10,384**	**$ 206**	**$ 432**	**$ 79,492**
Net book value							
At June 30, 2023	**$ 25,196**	**$ 141**	**$ 1,027**	**$ 38,218**	**$ 273**	**$ 120**	**$ 64,975**
At December 31, 2022	$ 25,240	$ 152	$ 1,055	$ 38,020	$ 276	$ 116	$ 64,859

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

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2022	$ 912	$ 377	$ 97	$ 61	$ 1,447
Additions	**17**	**92**	**32**	**1**	**142**
Depreciation	**(51)**	**(52)**	**(20)**	**(10)**	**(133)**
Foreign exchange adjustments and other	**1**	**1**	**(27)**	**—**	**(25)**
At June 30, 2023	**$ 879**	**$ 418**	**$ 82**	**$ 52**	**$ 1,431**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at June 30, 2023 were as follows:

	Jun 30 2023	Dec 31 2022
Lease liabilities	**$ 1,524**	$ 1,540
Less: current portion	**227**	244
	$ 1,297	$ 1,296

Total cash outflows for leases for the three months ended June 30, 2023, including payments related to short-term leases not reported as lease assets, were $341 million (three months ended June 30, 2022 – $289 million; six months ended June 30, 2023 – $678 million; six months ended June 30, 2022 – $556 million). Interest expense on leases for the three months ended June 30, 2023 was $16 million (three months ended June 30, 2022 – $15 million; six months ended June 30, 2023 – $32 million; six months ended June 30, 2022 – $30 million).

6. INVESTMENTS

As at June 30, 2023, the Company had the following investment:

	Jun 30 2023	Dec 31 2022
Investment in PrairieSky Royalty Ltd.	**$ 524**	$ 491

The (gain) loss from investments was comprised as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
(Gain) loss from investments	**$ (40)**	$ 25	**$ (33)**	$ (58)
Dividend income	**(5)**	(3)	**(11)**	(6)
	$ (45)	$ 22	**$ (44)**	$ (64)

The Company's 22.6 million common share investment in PrairieSky Royalty Ltd. does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at June 30, 2023, the market price per common share was $23.16 (December 31, 2022 – $21.70; June 30, 2022 – $16.21).

7. OTHER LONG-TERM ASSETS

	Jun 30 2023	Dec 31 2022
Prepaid cost of service tolls	**$ 191**	$ 199
Long-term inventory	**140**	137
Risk management (note 15)	**3**	9
Long-term contracts, prepayments and other [1]	**276**	269
	610	614
Less: current portion	**47**	61
	$ 563	$ 553

(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 (25% toll payer) of bitumen feedstock for the Company and 37,500 barrels per day (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), 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 16). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

The carrying value of the Company's interest in NWRP is $nil, and as at June 30, 2023, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $568 million (December 31, 2022 – $551 million). For the three months ended June 30, 2023, the unrecognized share of the equity loss was $1 million (six months ended June 30, 2023 – unrecognized equity loss of $17 million; three months ended June 30, 2022 – unrecognized equity loss of $15 million; six months ended June 30, 2022 – unrecognized equity loss of $25 million).

8. LONG-TERM DEBT

	Jun 30 2023	Dec 31 2022
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 1,691**	$ 1,702
US dollar denominated debt, unsecured		
Bank credit facilities (June 30, 2023 – US$375 million; December 31, 2022 – US$nil)	**496**	—
Commercial paper (June 30, 2023 – US$331 million; December 31, 2022 – US$nil)	**437**	—
US dollar debt securities (June 30, 2023 – US$7,250 million; December 31, 2022 – US$7,250 million)	**9,597**	9,812
	10,530	9,812
Long-term debt before transaction costs and original issue discounts, net	**12,221**	11,514
Less: original issue discounts, net [1]	**12**	13
transaction costs [1] [2]	**54**	56
	12,155	11,445
Less: current portion of commercial paper	**437**	—
current portion of other long-term debt [1] [2]	**1,882**	404
	$ 9,836	$ 11,041

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

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

Bank Credit Facilities and Commercial Paper

As at June 30, 2023, the Company had undrawn revolving bank credit facilities of $4,954 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit. At June 30, 2023, the Company had $437 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

- a $100 million demand credit facility;
- a $500 million revolving credit facility, maturing February 2024;
- a $2,425 million revolving syndicated credit facility, maturing June 2025; and
- a $2,425 million revolving syndicated credit facility, maturing June 2027.

During the second quarter of 2023, the Company extended its revolving syndicated credit facility originally maturing June 2024 to June 2027.

Borrowings under the Company's revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, 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 bank credit facilities and commercial paper outstanding as at June 30, 2023 was 5.5% (June 30, 2022 – N/A), and on total long-term debt outstanding for the six months ended June 30, 2023 was 4.7% (June 30, 2022 – 4.0%).

As at June 30, 2023, letters of credit and guarantees aggregating to $572 million were outstanding.

Medium-Term Notes

As at June 30, 2023, the Company had $3,000 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of medium-term notes in Canada. Subsequent to June 30, 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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. 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

As at June 30, 2023, the Company had US$3,000 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of debt securities in the United States. Subsequent to June 30, 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, replacing the Company's previous base shelf prospectus which would have expired in August 2023. 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.

9. OTHER LONG-TERM LIABILITIES

	Jun 30 2023	Dec 31 2022
Asset retirement obligations	**$ 6,845**	$ 6,908
Lease liabilities (note 5)	**1,524**	1,540
Share-based compensation	**667**	832
Transportation and processing contracts	**120**	159
Risk management (note 15)	**5**	3
Other	**69**	92
	9,230	9,534
Less: current portion	**1,270**	1,373
	$ 7,960	$ 8,161

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 5.6% (December 31, 2022 – 5.6%) and inflation rates of up to 2% (December 31, 2022 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Jun 30 2023	Dec 31 2022
Balance – beginning of period	**$ 6,908**	$ 6,806
Liabilities incurred	**16**	20
Liabilities acquired, net	**—**	11
Liabilities settled	**(237)**	(449)
Asset retirement obligation accretion	**183**	281
Revision of cost, inflation and timing estimates (1)	**—**	897
Impact of regulatory changes (2)	**—**	982
Change in discount rates	**—**	(1,698)
Foreign exchange adjustments	**(25)**	58
Balance – end of period	**6,845**	6,908
Less: current portion	**479**	495
	$ 6,366	$ 6,413

(1) Includes normal course revisions of cost, inflation and timing estimates, as well as revisions related to the acceleration of the abandonment of Ninian field assets in the North Sea at December 31, 2022.

(2) Reflects changes to the estimated timing of settlement of the Company's asset retirement obligations due to provincial regulatory changes in Alberta, British Columbia, and Saskatchewan in 2022.

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

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

	Jun 30 2023	Dec 31 2022
Balance – beginning of period	**$ 832**	$ 489
Share-based compensation expense	**136**	804
Cash payment for stock options surrendered and PSUs vested	**(107)**	(79)
Transferred to common shares	**(196)**	(387)
Other	**2**	5
Balance – end of period	**667**	832
Less: current portion	**508**	559
	$ 159	$ 273

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
Expense (recovery)	**Jun 30 2023**	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Current corporate income tax – North America (1)	**$ 299**	$ 855	**$ 779**	$ 1,689
Current corporate income tax – North Sea	**(4)**	15	**2**	22
Current corporate income tax – Offshore Africa	**20**	18	**30**	30
Current PRT (2) – North Sea	**(5)**	6	**(45)**	(1)
Other taxes	**3**	5	**6**	10
Current income tax	**313**	899	**772**	1,750
Deferred corporate income tax	**(15)**	131	**8**	256
Deferred PRT (2) – North Sea	**11**	—	**18**	—
Deferred income tax	**(4)**	131	**26**	256
Income tax	**$ 309**	$ 1,030	**$ 798**	$ 2,006

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

(2) Petroleum Revenue Tax.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares	Six Months Ended Jun 30, 2023 **Number of shares** (thousands)		**Amount**
Balance – beginning of period	**1,102,636**	**$**	**10,294**
Issued upon exercise of stock options	**4,924**		**190**
Previously recognized liability on stock options exercised for common shares	**—**		**196**
Purchase of common shares under Normal Course Issuer Bid	**(15,300)**		**(146)**
Balance – end of period	**1,092,260**	**$**	**10,534**

Dividend Policy

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

On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.90 per common share, beginning with the dividend paid on April 5, 2023. On November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share. On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share. On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, from $0.5875 per common share.

Normal Course Issuer Bid

On March 8, 2023, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 92,296,006 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2023 and ending March 12, 2024.

For the six months ended June 30, 2023, the Company purchased 15,300,000 common shares at a weighted average price of $76.80 per common share for a total cost of $1,175 million. Retained earnings were reduced by $1,029 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2023, up to and including August 1, 2023, the Company purchased 2,200,000 common shares at a weighted average price of $76.52 per common share for a total cost of $168 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at June 30, 2023:

	Six Months Ended Jun 30, 2023 **Stock options** (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**31,150**	**$**	**42.37**
Granted	**6,058**	**$**	**79.59**
Exercised for common shares	**(4,924)**	**$**	**38.56**
Surrendered for cash settlement	**(144)**	**$**	**38.56**
Forfeited	**(1,198)**	**$**	**49.31**
Outstanding – end of period	**30,942**	**$**	**50.01**
Exercisable – end of period	**5,635**	**$**	**37.35**

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

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Jun 30 2023	Jun 30 2022
Derivative financial instruments designated as cash flow hedges	**$ 74**	$ 77
Foreign currency translation adjustment	**103**	(30)
	$ 177	$ 47

13. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and 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%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. As at June 30, 2023, the ratio was below the target range at 23.7%.

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.

	Jun 30 2023	Dec 31 2022
Long-term debt	**$ 12,155**	$ 11,445
Less: cash and cash equivalents	**122**	920
Long-term debt, net	**$ 12,033**	$ 10,525
Total shareholders' equity	**$ 38,644**	$ 38,175
Debt to book capitalization	**23.7%**	21.6%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at June 30, 2023, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Six Months Ended	
		Jun 30 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Weighted average common shares outstanding – basic (thousands of shares)		**1,095,068**	1,151,111	**1,097,751**	1,157,914
Effect of dilutive stock options (thousands of shares)		**10,514**	15,464	**11,038**	15,482
Weighted average common shares outstanding – diluted (thousands of shares)		**1,105,582**	1,166,575	**1,108,789**	1,173,396
Net earnings		**$ 1,463**	$ 3,502	**$ 3,262**	$ 6,603
Net earnings per common share	– basic	**$ 1.34**	$ 3.04	**$ 2.97**	$ 5.70
	– diluted	**$ 1.32**	$ 3.00	**$ 2.94**	$ 5.63

15. 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)	**Jun 30 2023**	Dec 31 2022
Balance – beginning of period	**$ 6**	$ 55
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities (1)	**(8)**	70
Foreign exchange	**—**	(119)
Balance – end of period	**(2)**	6
Less: current portion	**(5)**	—
	$ 3	$ 6

(1) Risk management assets and liabilities are disclosed in note 7 and note 9, respectively.

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

	Three Months Ended		Six Months Ended	
	Jun 30 2023	Jun 30 2022	**Jun 30 2023**	Jun 30 2022
Net realized risk management (gain) loss	**$ (27)**	$ 7	**$ (26)**	$ 39
Net unrealized risk management (gain) loss	**(4)**	(21)	**16**	5
	$ (31)	$ (14)	**$ (10)**	$ 44

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:

	Jun 30, 2023	
	Carrying amount	**Level 1 Fair Value**
Fixed rate long-term debt (1) (2)	**$ (11,222)**	**$ (10,894)**

(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 financial statements for the year ended December 31, 2022.

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. At June 30, 2023, the Company had no significant 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 June 30, 2023, the Company had US$1,726 million of foreign currency forward contracts outstanding (December 31, 2022 - US$1,017 million), with original terms of up to 90 days, of which US$1,020 million were designated as derivatives held for trading (December 31, 2022 - US$1,017 million) and US$706 million were designated as cash flow hedges (December 31, 2022 - US$nil).

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, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at June 30, 2023, 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. As at June 30, 2023, the Company had net risk management assets of $1 million with specific counterparties related to derivative financial instruments (December 31, 2022 – $7 million). The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

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

As at June 30, 2023, 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	$	1,120	$	—	$	—	$	—
Accrued liabilities	$	3,860	$	—	$	—	$	—
Long-term debt (1)	$	2,319	$	794	$	3,115	$	5,993
Other long-term liabilities (2)	$	232	$	167	$	436	$	694
Interest and other financing expense (3)	$	629	$	566	$	1,386	$	3,540

(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, $227 million; one to less than two years, $167 million; two to less than five years, $436 million; and thereafter, $694 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 June 30, 2023.

16. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at June 30, 2023:

		Remaining 2023		2024		2025		2026		2027		Thereafter
Product transportation and processing (1)	$	594	$	1,394	$	1,262	$	1,157	$	1,106	$	11,337
North West Redwater Partnership service toll (2)	$	77	$	157	$	155	$	138	$	124	$	5,055
Offshore vessels and equipment	$	19	$	34	$	—	$	—	$	—	$	—
Field equipment and power	$	21	$	28	$	26	$	23	$	22	$	215
Other	$	12	$	24	$	23	$	17	$	—	$	—

(1) The Company's commitment for the 20-year product transportation agreement on the Trans Mountain Pipeline Expansion ("TMX") is subject to change pending approval of the interim toll filing by the Canada Energy Regulator.

(2) 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 $3,001 million of interest payable over the 40-year tolling period, ending in 2058 (note 7).

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

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2023	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Segmented product sales																
Crude oil and NGLs	**4,040**	6,470	**7,789**	12,009	**194**	220	**194**	347	**171**	181	**263**	398	**4,405**	6,871	**8,246**	12,754
Natural gas	**465**	1,501	**1,272**	2,431	**1**	1	**4**	6	**13**	15	**25**	29	**479**	1,517	**1,301**	2,466
Other income and revenue [1]	**(7)**	69	**4**	139	**—**	2	**—**	3	**5**	2	**7**	4	**(2)**	73	**11**	146
Total segmented product sales	**4,498**	8,040	**9,065**	14,579	**195**	223	**198**	356	**189**	198	**295**	431	**4,882**	8,461	**9,558**	15,366
Less: royalties	**(504)**	(1,309)	**(995)**	(2,216)	**(1)**	(1)	**(1)**	(1)	**(18)**	(19)	**(28)**	(30)	**(523)**	(1,329)	**(1,024)**	(2,247)
Segmented revenue	**3,994**	6,731	**8,070**	12,363	**194**	222	**197**	355	**171**	179	**267**	401	**4,359**	7,132	**8,534**	13,119
Segmented expenses																
Production	**918**	973	**1,920**	1,860	**149**	128	**152**	195	**37**	25	**64**	53	**1,104**	1,126	**2,136**	2,108
Transportation, blending and feedstock	**1,408**	1,847	**2,954**	3,599	**5**	2	**5**	4	**—**	—	**—**	—	**1,413**	1,849	**2,959**	3,603
Depletion, depreciation and amortization	**871**	855	**1,761**	1,733	**15**	50	**16**	79	**65**	42	**100**	93	**951**	947	**1,877**	1,905
Asset retirement obligation accretion	**58**	35	**117**	70	**12**	6	**23**	13	**2**	1	**4**	3	**72**	42	**144**	86
Risk management activities (commodity derivatives)	**(3)**	6	**17**	55	**—**	—	**—**	—	**—**	—	**—**	—	**(3)**	6	**17**	55
Total segmented expenses	**3,252**	3,716	**6,769**	7,317	**181**	186	**196**	291	**104**	68	**168**	149	**3,537**	3,970	**7,133**	7,757
Segmented earnings (loss)	**742**	3,015	**1,301**	5,046	**13**	36	**1**	64	**67**	111	**99**	252	**822**	3,162	**1,401**	5,362
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange (gain) loss																
(Gain) loss 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 Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2023	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Segmented product sales																
Crude oil and NGLs (2)	**3,546**	4,962	**8,028**	9,813	**15**	18	**36**	38	**149**	(124)	**217**	(105)	**8,115**	11,727	**16,527**	22,500
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**43**	88	**72**	141	**522**	1,605	**1,373**	2,607
Other income and revenue (1)	**8**	80	**27**	115	**203**	318	**453**	567	**—**	9	**3**	9	**209**	480	**494**	837
Total segmented product sales	**3,554**	5,042	**8,055**	9,928	**218**	336	**489**	605	**192**	(27)	**292**	45	**8,846**	13,812	**18,394**	25,944
Less: royalties	**(433)**	(1,008)	**(850)**	(1,545)	**—**	—	**—**	—	**—**	—	**—**	—	**(956)**	(2,337)	**(1,874)**	(3,792)
Segmented revenue	**3,121**	4,034	**7,205**	8,383	**218**	336	**489**	605	**192**	(27)	**292**	45	**7,890**	11,475	**16,520**	22,152
Segmented expenses																
Production	**997**	1,077	**2,039**	2,054	**91**	70	**169**	136	**19**	14	**31**	29	**2,211**	2,287	**4,375**	4,327
Transportation, blending and feedstock (2)	**582**	638	**1,132**	1,101	**162**	244	**315**	423	**173**	(49)	**258**	10	**2,330**	2,682	**4,664**	5,137
Depletion, depreciation and amortization	**442**	412	**930**	857	**4**	4	**8**	8	**—**	—	**—**	—	**1,397**	1,363	**2,815**	2,770
Asset retirement obligation accretion	**19**	16	**39**	31	**—**	—	**—**	—	**—**	—	**—**	—	**91**	58	**183**	117
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(3)**	6	**17**	55
Total segmented expenses	**2,040**	2,143	**4,140**	4,043	**257**	318	**492**	567	**192**	(35)	**289**	39	**6,026**	6,396	**12,054**	12,406
Segmented earnings (loss)	**1,081**	1,891	**3,065**	4,340	**(39)**	18	**(3)**	38	**—**	8	**3**	6	**1,864**	5,079	**4,466**	9,746
Non–segmented expenses																
Administration													**119**	97	**225**	213
Share-based compensation													**70**	(45)	**136**	489
Interest and other financing expense													**178**	160	**332**	323
Risk management activities (other)													**(28)**	(20)	**(27)**	(11)
Foreign exchange (gain) loss													**(202)**	333	**(216)**	187
(Gain) loss from investments													**(45)**	22	**(44)**	(64)
Total non-segmented expenses													**92**	547	**406**	1,137
Earnings before taxes													**1,772**	4,532	**4,060**	8,609
Current income tax													**313**	899	**772**	1,750
Deferred income tax													**(4)**	131	**26**	256
Net earnings													**1,463**	3,502	**3,262**	6,603

(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]

	Six Months Ended					
	Jun 30, 2023			Jun 30, 2022		
	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	**$ 34**	**$ (26)**	**$ 8**	$ 20	$ (33)	$ (13)
Offshore Africa	**1**	**—**	**1**	1	—	1
	35	**(26)**	**9**	21	(33)	(12)
Property, plant and equipment						
Exploration and Production						
North America	**1,628**	**(268)**	**1,360**	1,700	(195)	1,505
North Sea	**8**	**—**	**8**	38	(104)	(66)
Offshore Africa	**79**	**—**	**79**	35	(38)	(3)
	1,715	**(268)**	**1,447**	1,773	(337)	1,436
Oil Sands Mining and Upgrading	**1,055**	**(185)**	**870**	956	(499)	457
Midstream and Refining	**5**	**—**	**5**	5	(2)	3
Head Office	**16**	**—**	**16**	13	—	13
	2,791	**(453)**	**2,338**	2,747	(838)	1,909
	$ 2,826	**$ (479)**	**$ 2,347**	$ 2,768	$ (871)	$ 1,897

(1) This table provides a reconciliation of capitalized costs, reported in note 3 and note 4, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

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

Segmented Assets

	Jun 30 2023	Dec 31 2022
Exploration and Production		
North America	**$ 29,583**	$ 31,135
North Sea	**478**	378
Offshore Africa	**1,295**	1,322
Other	**23**	54
Oil Sands Mining and Upgrading	**42,746**	42,102
Midstream and Refining	**866**	979
Head Office	**168**	172
	$ 75,159	$ 76,142

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 2021. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended June 30, 2023:	
Interest coverage (times)	
Net earnings [(1)]	17.4x
Adjusted funds flow [(2)]	32.3x

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

(2) Adjusted funds flow plus current income taxes and interest expense; divided by interest expense.

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CORPORATE INFORMATION

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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

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