Canadian Natural

SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2019 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2019 SECOND QUARTER RESULTS

Commenting on the Company's second quarter 2019 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "Canadian Natural's second quarter results demonstrated the advantages of our diverse and balanced asset base combined with our flexible capital allocation resulting in significant adjusted funds flow in the quarter of approximately $2.7 billion. Throughout the first half of 2019 we were able to deliver on our four pillars of capital allocation through disciplined economic resource development, increasing returns to shareholders, strengthening our balance sheet and opportunistically acquiring accretive assets. The Company continues its focus on maximizing shareholder value while delivering responsible and sustainable operations."

Canadian Natural's President, Tim McKay, added, "Canadian Natural's ability to effectively and efficiently execute, delivered strong operating costs of $11.68/BOE across our Exploration and Production ("E&P") assets in the second quarter, resulting in operating cost reductions of 8% from both Q1/19 and Q2/18 levels. The Company achieved strong second quarter production of 1,025,800 BOE/d, strategically managing maintenance activities and optimizing its production volumes by executing on our curtailment optimization strategy.

The integration of the Devon assets that were recently acquired on June 27, 2019, continues to progress smoothly and our teams are working together to leverage learnings and maximize synergies between our existing and the acquired crude oil assets. Since the close of the acquisition, the Company has already realized significant cost savings. In addition, we are targeting to move a portion of heavy crude oil production from the acquired properties to the Company's 100% owned ECHO pipeline by the end of Q3/19, more than one year ahead of our initial plan."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, continued, "In the second quarter of 2019, the Company delivered another quarter of strong financial results with net earnings of approximately $2.8 billion and adjusted net earnings of approximately $1.0 billion, an increase of $204 million over Q1/19 levels.

Canadian Natural continues to deliver on its free cash flow allocation policy. In the first half of 2019, the Company returned a total of $1,484 million to shareholders, $852 million by way of dividends and $632 million by way of share purchases. Subsequent to the quarter, up to July 31, 2019, an additional 2.3 million common shares were purchased for cancellation at an average share price of $34.55. Our financial position remains strong as net long-term debt, excluding financing related to the recently closed acquisition, decreased by approximately $1.2 billion over Q1/19 levels. To fund the asset acquisition in the quarter, we successfully syndicated a 3 year, $3.25 billion term facility while available liquidity improved over the quarter to approximately $4.6 billion, including cash and cash equivalents.

At current strip pricing and based on our corporate guidance, we target to exit 2019 with a debt to adjusted EBITDA, debt to cash flow and debt to book capital ratios at levels below those existing at December 31, 2018, despite the completion of the $3.2 billion Devon acquisition which was financed through the Company's strong balance sheet and after returns to shareholders by way of dividends and share purchases throughout the year. The accretive Devon acquisition results in the Company growing long life low decline reserves and production and when combined with the robustness of the business model allows for significant free cash flow generation, continued returns to shareholders and further strengthening of our financial position through 2019."

QUARTERLY HIGHLIGHTS

	Three Months Ended			Six Months Ended	
($ millions, except per common share amounts)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Net earnings	**$ 2,831**	$ 961	$ 982	**$ 3,792**	$ 1,565
Per common share – basic	**$ 2.37**	$ 0.80	$ 0.80	**$ 3.17**	$ 1.28
– diluted	**$ 2.36**	$ 0.80	$ 0.80	**$ 3.16**	$ 1.27
Adjusted net earnings from operations (1)	**$ 1,042**	$ 838	$ 1,279	**$ 1,880**	$ 2,164
Per common share – basic	**$ 0.87**	$ 0.70	$ 1.05	**$ 1.57**	$ 1.77
– diluted	**$ 0.87**	$ 0.70	$ 1.04	**$ 1.57**	$ 1.76
Cash flows from operating activities	**$ 2,861**	$ 996	$ 2,613	**$ 3,857**	$ 5,082
Adjusted funds flow (2)	**$ 2,652**	$ 2,240	$ 2,706	**$ 4,892**	$ 5,029
Per common share – basic	**$ 2.22**	$ 1.87	$ 2.20	**$ 4.09**	$ 4.10
– diluted	**$ 2.22**	$ 1.86	$ 2.19	**$ 4.08**	$ 4.08
Cash flows used in investing activities	**$ 4,464**	$ 1,029	$ 1,138	**$ 5,493**	$ 2,507
Net capital expenditures, excluding Devon acquisition costs (3)	**$ 908**	$ 977	$ 974	**$ 1,885**	$ 2,077
Total net capital expenditures, including Devon acquisition costs (3)	**$ 4,125**	$ 977	$ 974	**$ 5,102**	$ 2,077
Daily production, before royalties					
Natural gas (MMcf/d)	**1,532**	1,510	1,539	**1,521**	1,576
Crude oil and NGLs (bbl/d)	**770,409**	783,512	793,899	**776,924**	824,060
Equivalent production (BOE/d) (4)	**1,025,800**	1,035,212	1,050,376	**1,030,480**	1,086,757

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key to evaluate 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. The derivation of this measure is discussed in the MD&A.

(3) Net capital expenditures is a non-GAAP measure that the Company considers a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. For additional information and details, refer to the net capital expenditures table in the Company's MD&A.

(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, 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.

- Net earnings of $2,831 million were realized in Q2/19, increases of $1,870 million and $1,849 million over Q1/19 and Q2/18 levels, respectively. Adjusted net earnings of $1,042 million were achieved in Q2/19, a $204 million increase over Q1/19 levels.
- Cash flows from operating activities were $2,861 million in Q2/19, an increase of $1,865 million compared to Q1/19 levels.
- Canadian Natural generated significant quarterly adjusted funds flow of $2,652 million in Q2/19, an increase of 18% or $412 million over Q1/19 levels. The increase over Q1/19 was primarily due to higher crude oil and NGLs netbacks in the Company's North America and International segments, partially offset by lower Synthetic Crude Oil ("SCO") production volumes in the Oil Sands Mining and Upgrading segment and lower natural gas netbacks.
- Cash flows used in investing activities were $4,464 million in Q2/19. Before net acquisitions, the Company's cash flows used in investing activities were $1,052 million in Q2/19.

- Canadian Natural delivered strong quarterly free cash flow of $1,295 million after net capital expenditures of $908 million, and dividend requirements of $449 million, excluding costs related to the recently closed acquisition, reflecting the strength of our long life low decline asset base and our effective and efficient operations.
- Canadian Natural is committed to returns to shareholders, returning a total of $840 million in the quarter, $449 million by way of dividends and $391 million by way of share purchases. In the first half of 2019, the Company has returned a total of $1,484 million to shareholders, $852 million by way of dividends and $632 million by way of share purchases.
  - Share purchases for cancellation in the quarter totaled 10,450,000 common shares at a weighted average share price of $37.41.
  - Subsequent to quarter end, up to and including July 31, 2019, the Company executed on additional share purchases for cancellation of 2,300,000 common shares at a weighted average share price of $34.55.
  - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on October 1, 2019.
- Capital expenditures in the first six months of 2019 were approximately $190 million below the original budget, showing strong discipline on capital spending with flexibility for potential execution of these projects later in 2019 or into 2020. Annual 2019 corporate capital guidance has increased by $100 million, representing amounts required to maintain the acquired Devon assets.
- **Curtailment Optimization Strategy Update**
  - On December 5, 2018, the Company released its budgeted annual 2019 production guidance which only included Company originated estimated voluntary curtailments through to the end of Q2/19. Subsequently, on January 1, 2019, the Government of Alberta mandatory curtailment program came into effect, which superseded the Company's voluntary curtailment estimates. The government mandatory curtailment has been successful in stabilizing the crude oil differential discount that Alberta was receiving for both light crude oil and heavy crude oil. As the year has progressed, mandatory curtailments have continued and timing of the cessation of mandatory curtailments remains uncertain. Crude by rail has continued to increase from Q1/19 levels, while storage levels have trended down, albeit at a slower rate than was originally envisioned. As a result, the Company now budgets for continued government mandated curtailments through to the end of 2019. The Company currently has significant additional production capacity beyond the currently mandated curtailed production levels available and continues to execute operational flexibility through its curtailment optimization strategy as follows:
    - Mitigating production impacts from unplanned maintenance activities at both Scotford and Horizon by increasing conventional and thermal in situ crude oil production. As a result of the Company's execution on its curtailment optimization strategy, North America Exploration and Production ("E&P") and thermal in situ oil sands production exceeded Q2/19 production guidance, excluding acquisition volumes.
    - During the planned turnaround at Horizon in the fall, the Company targets to achieve its mandatory curtailment allowable by executing its curtailment optimization strategy along with production from pad additions at Primrose, which continue to be ahead of schedule, demonstrating the Company's ability to manage production while under curtailment.
    - Modifying timing of the Company's planned turnaround activities to achieve its monthly curtailment allowable.
    - Maximizing value through production optimization of higher netback assets and reducing operating costs.
    - Despite mandatory government curtailments being beyond the Company budgeted voluntary curtailment estimates, the Company's revised production guidance still remains in the range of original budget guidance levels, adjusted for the targeted production from the recently closed Devon acquisition, reflecting the Company’s strong asset base, flexible operations as well as the implementation of the Company's curtailment optimization strategy.
- On June 27, 2019, the Company successfully closed the acquisition of substantially all of the assets of Devon Canada Corporation, adding to the Company's long life low decline asset base. In total, approximately 720 employees were successfully transitioned to Canadian Natural. The Company's teams are working together to leverage technology and maximize synergies between the existing and acquired crude oil assets. The Company is ahead of its initial plan in achieving targeted annual cost savings of $135 million which includes the following cost saving opportunities, for both primary heavy and thermal in situ crude oil assets, with the potential for more:
  - The Company is targeting to consolidate acquired facilities and move a portion of the heavy crude oil production from the acquired properties to its 100% owned ECHO pipeline by the end of Q3/19, more than one year ahead of its initial plan, targeting approximately $25 million in margin improvements per year.

- Utilizing acquired sand storage, deferring the need to construct a new facility.
- Redirecting approximately 3,700 bbl/d of primary heavy crude oil previously processed by a third party to Canadian Natural facilities.
- Reducing trucking costs through optimization of fluids in field production tanks, and disposing of water volumes at acquired facilities.
- Capturing operating cost synergies through consolidation of regional camps and aerodromes.
- Capturing economies of scale for warehousing, contracting, as well as parts and procurement.
- Leveraging operational and technical expertise for preventative maintenance programs across the thermal in situ Steam Assisted Gravity Drainage ("SAGD") assets.
- Reducing costs by optimizing well servicing activities and rig utilization.

▪ Canadian Natural's continued focus on delivering effective and efficient operations was demonstrated as the Company's Exploration and Production ("E&P") Q2/19 operating costs were $11.68/BOE, an 8% reduction from both Q1/19 and Q2/18 levels.

▪ The Company achieved quarterly production volumes of 1,025,800 BOE/d in Q2/19, comparable to Q1/19 and a 2% decrease from Q2/18 levels, reflecting the Company's execution on its curtailment optimization strategy to offset the impacts of the extended time to complete repairs at the Scotford Upgrader and proactive maintenance activities at Horizon, as well as production impacts of approximately 6,300 bbl/d from wildfires near the Company's Pelican Lake and Woodenhouse operations.

▪ Canadian Natural's North America E&P crude oil and NGLs production volumes, excluding thermal in situ, averaged 235,066 bbl/d in Q2/19, exceeding Q2/19 production guidance and a 4% increase over Q1/19 levels. The increase was primarily due to execution on the Company's curtailment optimization strategy, partially offset by production impacts in late May and early June of approximately 6,300 bbl/d of quarterly production lost due to wildfires near the Company's Pelican Lake and Woodenhouse operations. The Company restarted operations at Pelican Lake on June 8, 2019 and production for July averaged approximately 62,000 bbl/d, comparable to rates prior to the shutdown.

▪ Thermal in situ oil sands production volumes averaged 109,599 bbl/d in Q2/19, a 16% increase over Q1/19 levels, primarily due to execution on the Company's curtailment optimization strategy and additional volumes from the Devon asset acquisition that closed on June 27, 2019. Excluding the acquisition volumes, thermal in situ crude oil production exceeded Q2/19 production guidance.

  - Pad additions at Primrose continue to be ahead of schedule and on budget with initial production targeted in Q3/19, offsetting production impacts from the planned turnaround at Horizon as part of the Company's curtailment optimization strategy. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.
  - As previously announced, at the Company's Kirby North SAGD project, top tier execution and strong productivity have resulted in the project remaining two quarters ahead of the sanctioned schedule with overall cost performance remaining on budget. The commissioning of the central processing facility was ahead of schedule and as a result, the project began steaming in Q2/19. As part of the Company's curtailment optimization strategy, the Company targets to manage the ramp up of production towards Kirby North's overall capacity of 40,000 bbl/d in early 2021.

▪ North America natural gas production was 1,482 MMcf/d in Q2/19, an increase of 2% over Q1/19 levels and comparable with Q2/18 levels. The increase in Q2/19 was primarily due to associated gas from the Company's light crude oil and liquids rich natural gas drilling program, partially offset by natural field declines.

▪ International E&P production volumes were strong in Q2/19, averaging 51,244 bbl/d, increasing by 7% and 20% over Q1/19 and Q2/18 levels, respectively. The increases over the comparable periods are due to the successful drilling programs at Ninian and Baobab, partially offset by the planned turnaround at Ninian and natural field declines. As a result these strong operational results, the Company has increased its annual 2019 International production guidance.

  - International production volumes benefit from premium Brent pricing, generating significant free cash flow for the Company.

▪ At the Company's world class Oil Sands Mining and Upgrading assets, second quarter production volumes averaged 374,500 bbl/d of SCO, a decrease of 10% from Q1/19 levels. The decrease in production primarily reflected extended time to complete repairs at the Scotford Upgrader, as well as proactive maintenance activities at Horizon. After completion of these repairs and maintenance activities Oil Sands Mining production has been strong, averaging approximately 463,000 bbl/d of SCO production in the month of July.

- Total production costs were $814 million in Q2/19, comparable to Q1/19 levels and a 5% decrease from $855 million in Q2/18. Production costs for the first half of 2019 were $1,636 million, a 5% or $92 million decrease from the comparable period in 2018, demonstrating the Company's focus on effective and efficient operations.
- Canadian Natural realized quarterly operating costs of $24.17/bbl (US$18.06/bbl) of SCO in Q2/19, a 13% increase over Q1/19 and a 5% increase over Q2/18 levels, reflecting lower production volumes in the quarter.
- At Horizon, as a result of Canadian Natural's industry leading integrity program, the Company identified a portion of the piping to the amine unit that had reduced thickness and made the proactive decision to advance this maintenance in Q2/19, ahead of the planned fall turnaround. The Company was able to mitigate some of the production impact from the 16 day outage by bringing on curtailed production.
  - The Company has reviewed and optimized the scope of work for the planned Horizon fall turnaround and as a result, the turnaround is now targeted for 25 days starting in late Q3/19, a reduction of 3 days.

▪ Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At June 30, 2019 the Company had approximately $4,560 million of available liquidity, including cash and cash equivalents.

ENVIRONMENTAL HIGHLIGHTS

▪ In July 2019, Canadian Natural published its 2018 Stewardship Report to Stakeholders, now available on the Company's website at https://www.cnrl.com/report-to-stakeholders. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. Highlights from the 2018 report are as follows:
- Canadian Natural's corporate greenhouse gas ("GHG") emissions intensity has decreased by approximately 29% from 2012 to 2018, a material reduction in emissions intensity.
- The Company's corporate GHG emissions intensity decreased in 2018 by approximately 5% from 2017 levels, including a reduction of approximately 18% in Oil Sands Mining and Upgrading.
- Methane emissions have decreased 78% from 2012 to 2018 at the Company's Alberta primary heavy crude oil operations.
- In the Company's North America E&P segment, in 2018 natural gas flaring decreased by 4% and natural gas venting decreased by 6% from 2017 levels.
- In 2018, in the Company's North America E&P segment, Canadian Natural abandoned 1,293 wells, an increase of 68% over 2017 levels, and submitted 1,012 reclamation certificates, an increase of approximately 67% over 2017 levels.
- The Company reclaimed 1,383 hectares of land in 2018 in the Company's North America E&P segment, equivalent to approximately 1,700 Canadian football fields and a 9% increase over 2017 levels.
- In the Oil Sands Mining and Upgrading segment, water use intensity decreased in 2018 by 30% from 2017 levels.
- Approximately 75% of water used at Primrose was sourced from recycled produced water in 2018.

▪ Canadian Natural has invested over $3.4 billion in research and development since 2009 and continues to invest in technology to unlock reserves, become more effective and efficient, increase production and reduce the Company's environmental footprint. Canadian Natural's culture of continuous improvement leverages the use of technology and innovation to drive sustainable operations and long-term value for shareholders.

▪ Canadian Natural has invested significant capital to capture and sequester CO_2. The Company has carbon capture and sequestration facilities at Horizon, a 70% working interest in the Quest Carbon Capture and Storage project at Scotford, and through carbon capture facilities through its 50% interest in the NWR refinery. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of CO_2 annually, equivalent to taking 576,000 vehicles off the road per year, making the Company one of the largest CO_2 capturer and sequester for the oil and natural gas sector globally.

▪ Canadian Natural's commitment to leverage technology, adopting innovation and continuous improvement is evidenced by its In Pit Extraction Process ("IPEP") pilot at Horizon, which will determine the feasibility of producing stackable dry tailings. The project has the potential to reduce the Company's carbon emissions and environmental footprint by reducing the usage of haul trucks, the size and need for tailings ponds and accelerating site reclamation. In addition, this process has the potential to significantly reduce capital and operating costs.

- The initial testing phase for the Company's IPEP pilot has concluded and results have been positive with excellent recovery rates and evidence of stackable tailings. Given the positive results thus far, the Company continues to make enhancements and will operate and test the pilot through 2019.

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, thermal in situ crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. This balance provides optionality for capital investments, maximizing value for the Company's shareholders.

Underpinning this asset base is long life low decline production from the Company's Oil Sands Mining and Upgrading, thermal in situ oil sands and Pelican Lake heavy crude oil assets. The combination of long life low decline, low reserves replacement cost, and effective and efficient operations results in substantial and sustainable adjusted funds flow throughout the commodity price cycle.

Augmenting this, 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 with the right economic conditions, can provide excellent returns and maximize value for shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs which 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			
	2019		2018	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**39**	**38**	210	203
Natural gas	**12**	**10**	13	9
Dry	**3**	**3**	2	2
Subtotal	**54**	**51**	225	214
Stratigraphic test / service wells	**379**	**335**	555	477
Total	**433**	**386**	780	691
Success rate (excluding stratigraphic test / service wells)		**94%**		99%

- The Company's total crude oil and natural gas drilling program of 51 net wells for the six months ended June 30, 2019, excluding strat/service wells, decreased by 163 net wells from the same period in 2018. The Company's drilling levels reflect the disciplined capital allocation process, continued actions to enhance operations, and execution on the Company's curtailment optimization strategy.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs production (bbl/d)	**235,066**	225,291	238,631	**230,205**	242,101
Net wells targeting crude oil	**9**	28	58	**37**	159
Net successful wells drilled	**7**	28	58	**35**	157
Success rate	**78%**	100%	100%	**95%**	99%

- North America E&P crude oil and NGLs production volumes averaged 235,066 bbl/d in Q2/19, exceeding Q2/19 production guidance and a 4% increase over Q1/19 levels. The increase was primarily due to execution on the

Company's curtailment optimization strategy, partially offset by production impacts of approximately 6,300 bbl/d from wildfires near the Company's Pelican Lake and Woodenhouse operations.

- Canadian Natural's primary heavy crude oil production averaged 77,667 bbl/d in Q2/19, a 13% increase over Q1/19 levels primarily due to execution on the Company's curtailment optimization strategy and additional volumes from the Devon asset acquisition that closed on June 27, 2019. Primary heavy crude oil production decreased by 8% from Q2/18 levels primarily due to the Company's strategic decision to reduce activity through 2018 as a result of the widening price differentials in 2018 and the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019.
    - Operating costs of $17.52/bbl were achieved in the Company's primary heavy crude oil operations in the quarter, comparable to Q1/19 and a 3% increase over Q2/18 levels, strong results given the 8% decrease in volumes.
    - The Company drilled 5 net primary heavy crude oil wells in Q2/19, targeting strategic opportunities for future development, particularly in Saskatchewan, where 3 of the 5 wells were drilled as production is not impacted by curtailments. Canadian Natural is leveraging the Company's multilateral horizontal technology expertise on 2 of these wells.
        - An additional 11 net multilateral horizontal wells, primarily in Saskatchewan, are targeted to be drilled in the last half of the year. By leveraging technology and taking advantage of the Company's expertise, the Company continues to unlock value in its primary heavy crude oil assets.
    - The recently acquired primary heavy crude oil Manatokan lands, with the potential for 658 net locations, are an excellent fit within the Company's existing primary heavy crude oil operations. As part of the Company's continued focus on technology and innovation, 85% of the identified potential locations are multilateral horizontal wells. The Company's teams are working together to leverage technology and maximize synergies.
    - The Company is ahead of its initial plan in achieving targeted annual cost savings of $135 million on the Devon properties, including both primary heavy and thermal in situ crude oil assets. In addition to economies of scale, the Company has identified the following primary heavy crude oil cost saving opportunities, with the potential for more:
        - The Company is targeting to consolidate acquired facilities and move a portion of the heavy crude oil production from the acquired properties to the Company's 100% owned ECHO pipeline by the end of Q3/19, more than one year ahead of its initial plan, targeting approximately $25 million in margin improvements per year.
        - Utilizing acquired sand storage, deferring the need to construct a new facility.
        - Redirecting approximately 3,700 bbl/d of primary heavy crude oil previously processed by a third party to Canadian Natural facilities.
        - Reducing trucking costs through optimization of fluids in field production tanks, and disposing of water volumes at acquired facilities.
- North America light crude oil and NGL production averaged 102,368 bbl/d in Q2/19, a 14% increase over Q2/18 and 7% increase over Q1/19 levels, reflecting the Company's strategic decision to reallocate capital to light crude oil and liquids rich areas, along with strong results from the 2018 and 2019 drilling programs at Wembley, Karr, and Southeast Saskatchewan, and execution on the Company's curtailment optimization strategy.
    - Within the greater Wembley area, results continue to exceed expectations. In the first half of the year, the Company brought 12 net wells on production with initial 30 day liquids production rates averaging approximately 680 bbl/d per well, exceeding expectations of approximately 560 bbl/d per well. An additional 2 net wells are targeted to come on production in Q3/19. The Company has identified the potential for 363 incremental high quality premium light crude oil and liquids rich Montney drilling locations on the Company's 155 net sections.
    - In the first half of the year, in the Company's Karr area, 12 net wells have come on production, delivering strong results. The wells are currently producing at approximately 2,750 bbl/d total, in-line with expectations and being further optimized. Canadian Natural holds approximately 50 net sections of prospective Dunvegan rights with the potential of 45 high quality light crude oil locations. The Company is currently evaluating water flood implementation at Karr to increase recoveries and maximize long term value.
    - In Southeast Saskatchewan, the Company drilled 4 net light crude oil wells in Q2/19, with an additional 7 net wells targeted to be drilled in Q3/19. All 11 of these high return wells are targeted to be on stream in Q3/19,

with expected rates averaging approximately 80 bbl/d per well. The Company strategically reallocated capital from Alberta to Saskatchewan as production from these wells are not impacted by the Government of Alberta mandated production curtailments.

   - In Q2/19 operating costs of $14.67/bbl were strong in the Company's North America light crude oil and NGL areas, decreases of 8% and 7% from Q1/19 and Q2/18 levels respectively, primarily due to increased production volumes and the Company's focus on cost control.

 - Pelican Lake quarterly production averaged 55,031 bbl/d in Q2/19, a decrease of 10% from Q1/19 levels, reflecting production impacts of approximately 5,400 bbl/d from the temporary shut-in of crude oil production due to wildfires in northern Alberta.

   - As previously announced, Canadian Natural completed a safe, temporary shut down of Pelican Lake production on May 30, 2019 due to wildfires in the region. The Company restarted operations on June 8, 2019 and production for July averaged approximately 62,000 bbl/d, comparable to rates prior to the shut down.

   - Strong operating costs of $6.72/bbl were achieved in Q2/19 at Pelican Lake, comparable to Q1/19 and a 3% decrease from Q2/18 levels, impressive results given the decrease in production due to the Alberta wildfires in the quarter.

- The Company's annual 2019 North America E&P crude oil and NGL production guidance has been increased to incorporate the Devon acquisition and is now targeted to range between 231,000 bbl/d - 251,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Bitumen production (bbl/d)	**109,599**	94,146	104,907	**101,915**	108,359
Net wells targeting bitumen	**—**	—	21	**—**	43
Net successful wells drilled	**—**	—	21	**—**	43
Success rate	**—**	—	100%	**—**	100%

- Thermal in situ oil sands production volumes averaged 109,599 bbl/d in Q2/19, a 16% increase over Q1/19 levels, primarily due to the Company's execution on its curtailment optimization strategy and additional volumes from the Devon asset acquisition that closed on June 27, 2019. Excluding the acquisition volumes, thermal in situ crude oil production exceeded Q2/19 production guidance.

 - At Primrose, Q2/19 production volumes averaged 71,917 bbl/d, an increase of 16% over Q1/19 levels, primarily due to execution on the Company's curtailment optimization strategy. Including energy costs, operating costs were strong at $12.39/bbl in Q2/19, decreases of 39% and 15% from Q1/19 and Q2/18 levels respectively, reflecting higher volumes and lower energy costs.

   - Pad additions at Primrose continue to be ahead of schedule and on budget with initial production targeted in Q3/19, offsetting production impacts from the planned turnaround at Horizon as part of the Company's curtailment optimization strategy. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.

 - At Kirby South, SAGD production volumes averaged 28,597 bbl/d in Q2/19, a 4% decrease from Q1/19 and a 19% decrease from Q2/18 levels. Including energy costs, Kirby South quarterly operating costs were strong at $10.55/bbl in Q2/19, a reduction of 14% from Q1/19 levels, primarily as a result of lower energy costs. Operating costs increased by 16% from Q2/18 levels primarily due to lower production volumes.

   - In Q2/19 at Kirby South, the Company began its solvent enhanced SAGD pilot as planned. Initial results are positive indicating reduced Steam to Oil Ratios ("SORs") in line with expectations. If successful, solvent enhanced SAGD has the potential to significantly reduce SORs, operating costs and greenhouse gas emissions. The Company targets to continue to operate the pilot for approximately 2 years.

- As previously announced, at the Company's Kirby North SAGD project, top tier execution and strong productivity have resulted in the project remaining two quarters ahead of the sanctioned schedule with overall cost performance remaining on budget. The commissioning of the central processing facility was ahead of schedule and as a result, the project began steaming in Q2/19. As part of the Company's curtailment optimization strategy, the Company targets to manage the ramp up of production towards Kirby North's overall capacity of 40,000 bbl/d in early 2021.
- The recently acquired Jackfish thermal in situ crude oil assets are an excellent fit with our existing thermal in situ crude oil assets, adding to the Company's long life low decline asset base. The Company's teams are working together to leverage technology and maximize synergies between the existing and acquired crude oil assets.
- The Company is ahead of its initial plan in achieving targeted annual cost savings of $135 million on the Devon properties, including both thermal in situ and primary heavy crude oil assets. The Company has identified the following thermal in situ crude oil cost savings and optimization opportunities, with the potential for more:
  - Capturing operating cost synergies through consolidation of regional camps and aerodromes.
  - Capturing economies of scale for warehousing, contracting, as well as parts and procurement.
  - Leveraging operational and technical expertise for preventative maintenance programs across the thermal in situ SAGD assets.
  - Reducing costs by optimizing well servicing activities and rig utilization.

▪ The Company’s annual 2019 thermal in situ production guidance has been increased to incorporate the Devon acquisition and is now targeted to range between 157,000 bbl/d - 172,000 bbl/d.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Natural gas production (MMcf/d)	**1,482**	1,454	1,485	**1,468**	1,515
Net wells targeting natural gas	**2**	9	4	**11**	9
Net successful wells drilled	**2**	8	4	**10**	9
Success rate	**100%**	89%	100%	**91%**	100%

▪ North America natural gas production was 1,482 MMcf/d in Q2/19, an increase of 2% over Q1/19 levels and comparable with Q2/18 levels. The increase in Q2/19 was primarily due to associated gas from the Company's light crude oil and liquids rich natural gas drilling program, partially offset by natural field declines.

▪ Strong operating costs of $1.15/Mcf were achieved in Q2/19, a decrease of 12% from Q1/19 and 10% from Q2/18 levels, primarily due to the Company's continued focus on cost control and due to the 2% increase in volumes over Q1/19 levels.

▪ At the Company's high value Septimus Montney liquids rich area, 5 net wells, with targeted production capacity of approximately 2,080 bbl/d of NGLs and 30 MMcf/d of natural gas, were completed in late Q2/19. Rates for the new wells are in line with expectations. The Septimus plant is expected to be maintained at full capacity for the remainder of 2019.

- Septimus operating costs were $0.33/Mcfe in Q2/19, an 8% reduction from Q1/19 levels, and a further reduction of 12% to $0.29/Mcfe is targeted for the remainder of 2019. Continued low operating costs at Septimus support the Company's high value liquids rich development.

▪ The Company's natural gas reinjection pilot at Septimus commenced its first injection of 5 MMcf/d in Q2/19. Depending on results of the pilot, this technology has the potential to materially increase liquids recovery while storing natural gas in the reservoir, preserving the value of the natural gas for periods with higher market prices.

- Results from the first injection and production cycle are targeted for late 2019 with the potential to proceed with additional cycles at the same location. Given the opportunities for this process across Canadian Natural's vast liquids rich Montney land base, the Company is advancing readiness for a second pilot site within the Company's Greater Wembley area.

▪ A portion of the capital reallocated from Alberta crude oil projects was deployed in the Company's liquids rich Gold Creek assets, which are not subject to curtailment. In the Gold Creek area, 2 net wells came on production in Q2/19 with initial rates of approximately 650 bbl/d and 4.9 MMcf/d per well, exceeding liquids expectations by 44% per well. Subsequent to quarter end, an additional 2 net wells came on production with initial rates of approximately 900 bbl/d and 5 MMcf/d per well, exceeding liquids expectations by 43% per well.

- The Company successfully closed the acquisition of the Pine River plant on May 3, 2019. A 45 day planned plant turnaround designed to improve plant efficiency, run time, lower operating costs, and improve plant capability to 120 MMcf/d from current levels of 95 MMcf/d, is targeted to commence in late Q3/19.
- In 2019, based upon the midpoint of annual production guidance, Canadian Natural targets to use the equivalent of approximately 45% of its total corporate natural gas production in its operations, providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 34% of the Company's guided 2019 natural gas production is targeted to be exported to other North American markets and sold internationally. The remaining 21% of the Company's 2019 targeted natural gas production would be exposed to AECO/Station 2 pricing.
- The Company's annual 2019 corporate natural gas production guidance remains unchanged and is targeted to range between 1,485 MMcf/d - 1,545 MMcf/d.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil production (bbl/d)					
North Sea	**27,594**	25,714	24,456	**26,659**	23,028
Offshore Africa	**23,650**	22,155	18,201	**22,907**	18,816
Natural gas production (MMcf/d)					
North Sea	**23**	28	30	**25**	34
Offshore Africa	**27**	28	24	**28**	27
Net wells targeting crude oil	**0.9**	1.6	1.9	**2.5**	2.9
Net successful wells drilled	**0.9**	1.6	1.9	**2.5**	2.9
Success rate	**100%**	100%	100%	**100%**	100%

- International E&P production volumes were strong in Q2/19, averaging 51,244 bbl/d, increasing by 7% and 20% over Q1/19 and Q2/18 levels, respectively. The increases from the comparable periods are due to the successful drilling programs at Ninian and Baobab, partially offset by the planned turnaround at Ninian and natural field declines.
- International production volumes benefit from premium Brent pricing, generating significant free cash flow for the Company.
  - In the North Sea, production volumes of 27,594 bbl/d were achieved in Q2/19, increasing by 7% and 13% over Q1/19 and Q2/18 levels, respectively. The increases over Q1/19 and Q2/18 were primarily as a result of successful drilling in 2018 and the first half of 2019, partially offset by planned maintenance activities at the Ninian Central Platform and natural field declines. Current production for the 2 gross (1.9 net) wells drilled in 2019 is exceeding budgeted expectations of 4,200 bbl/d net, by approximately 1,000 bbl/d.
    - Q2/19 operating costs in the North Sea averaged $37.31/bbl (£22.39/bbl), a reduction of 6% from Q1/19 levels, primarily due to timing of liftings from various fields that have different cost structures, partially offset by the impact of turnaround costs.
    - In the second half of 2019, the Company targets to drill 3 gross (2.9 net) high netback producer wells. The total 2019 North Sea drilling program now consists of 5 gross (4.8 net) high return producer wells, capturing improving margins in the Company's successful North Sea operations.
    - The Company is targeting planned turnaround activities at the Tiffany platform and Banff Floating Production Storage and Offloading ("FPSO") vessel in Q3/19. Production impacts are reflected in Q3/19 guidance.
  - Offshore Africa production volumes in Q2/19 averaged 23,650 bbl/d, increases of 7% and 30% increase over Q1/19 and Q2/18 levels, respectively. The increases over Q1/19 and Q2/18 were primarily as a result of production from the successful Baobab drilling program, partially offset by natural field declines.

- ◦ Côte d'Ivoire crude oil operating costs averaged $8.40/bbl (US$6.28/bbl) in Q2/19, a reduction of 14% from Q1/19 levels primarily due to increased volumes and timing of liftings from various fields that have different cost structures.
- ◦ In Q2/19, the Company drilled 1.0 gross (0.6 net) injector well, completing the Baobab drilling program. The total Baobab drilling program of 4 gross (2.4 net) producer wells and 2 gross (1.2 net) injectors was completed on budget. Production from the new wells is exceeding budgeted expectations by approximately 3,000 bbl/d net.
- ◦ As previously announced, the Company had targeted to commence a high value drilling program in Q4/19 at Espoir. Due to ongoing discussions with the Côte d'Ivoire Government, the Espoir drilling program has been canceled until such time as certain foreign exchange practices can be clarified.
- ◦ Canadian Natural successfully drilled an appraisal well (0.6 net) at Kossipo in Q2/19. The well flowed light crude oil at a facility constrained rate of 7,360 bbl/d, exceeding expectations. The Company is currently evaluating project economics and contractual terms for development drilling and a pipeline tied-back to the Baobab FPSO vessel, adding significant future value with potential gross production capability of 20,000 bbl/d targeted in 2022.

- • Following the previously announced discovery of significant gas condensate in South Africa, where Canadian Natural owns a 20% working interest, the operator targets to acquire 3D seismic on the Block in 2019.
  - ◦ In the first half of 2020, the operator targets to drill 1 gross exploration well and depending on results, may drill 2 additional wells to further define volumes and deliverability.

- ▪ Based on positive drilling results, the Company's annual 2019 International production guidance has been increased and is now targeted to range from 46,000 bbl/d - 50,000 bbl/d.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Synthetic crude oil production (bbl/d) (1) (2)	**374,500**	416,206	407,704	**395,238**	431,756

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

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

- ▪ At the Company's world class Oil Sands Mining and Upgrading assets, quarterly production volumes averaged 374,500 bbl/d of SCO, a decrease of 10% from Q1/19 levels. The decrease in production primarily reflected extended time to complete repairs at the Scotford Upgrader, as well as proactive maintenance activities at Horizon.
  - • Total production costs were $814 million in Q2/19, comparable to Q1/19 levels and a 5% decrease from $855 million in Q2/18. Production costs for the first half of 2019 were $1,636 million, a 5% or $92 million decrease from the comparable period in 2018, demonstrating the Company's focus on effective and efficient operations.
  - • Canadian Natural realized quarterly operating costs of $24.17/bbl (US$18.06/bbl) of SCO in Q2/19, a 13% increase over Q1/19 and a 5% increase over Q2/18 levels, reflecting lower production volumes in the quarter.
  - • As previously announced, a fire occurred at the non-operated Scotford North Upgrader on April 15, 2019. The fire was promptly extinguished, all personnel were accounted for, and there were no reported injuries. Repairs were successfully completed for approximately $21 million gross and took an additional 28 days to complete following the planned 38 day turnaround. Operations resumed to full production on June 24, 2019 and the Company was able to minimize the impacts of Scotford repairs by bringing on curtailed production in other areas of its asset base.
  - • At Horizon, as a result of Canadian Natural's industry leading integrity program, the Company identified a portion of the piping to the amine unit that had reduced thickness and made the proactive decision to advance this maintenance in Q2/19, ahead of the planned fall turnaround. The Company was able to mitigate some of the production impact from the 16 day outage by bringing on curtailed production.
    - ◦ The Company has reviewed and optimized the scope of work for the planned Horizon fall turnaround and as a result, the turnaround is now targeted for 25 days starting in late Q3/19, a reduction of 3 days.

- The Company continues to progress engineering work on the previously announced potential expansion opportunities at Horizon to increase reliability and lower costs, targeting to add production of 75,000 bbl/d to 95,000 bbl/d. The engineering and design specification work continued in the quarter and is targeted to be complete in Q3/19. The final investment decision on these opportunities will not be made until there is greater clarity on market access.
  - The potential Paraffinic Froth Treatment expansion at Horizon is targeting 40,000 bbl/d to 50,000 bbl/d of high quality diluted bitumen at significantly lower operating costs as the Company leverages its existing infrastructure. The preliminary estimate of the capital required is approximately $1.4 billion.
  - Stage 1 and 2 reliability opportunities at Horizon are targeted to add 35,000 bbl/d to 45,000 bbl/d of SCO.

- Based on the impacts of the repairs and maintenance activities undertaken in the Company's Oil Sands Mining and Upgrading operations in Q2/19, the Company's annual 2019 Oil Sands Mining and Upgrading production guidance has been adjusted and is now targeted to range between 405,000 bbl/d - 415,000 bbl/d of SCO.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 59.83**	$ 54.90	$ 67.90	**$ 57.38**	$ 65.41
WCS heavy differential as a percentage of WTI (%) (2)	**18%**	23%	28%	**20%**	33%
SCO price (US$/bbl)	**$ 59.96**	$ 52.19	$ 67.27	**$ 56.10**	$ 64.38
Condensate benchmark pricing (US$/bbl)	**$ 55.86**	$ 50.49	$ 68.85	**$ 53.19**	$ 66.00
Average realized pricing before risk management (C$/bbl) (3)	**$ 63.45**	$ 53.98	$ 61.14	**$ 59.05**	$ 52.32
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.11**	$ 1.84	$ 0.97	**$ 1.47**	$ 1.36
Average realized pricing before risk management (C$/Mcf)	**$ 1.98**	$ 3.09	$ 1.95	**$ 2.53**	$ 2.35

(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.

- Q2/19 differentials between Western Canadian Select ("WCS") and WTI benchmark pricing narrowed from Q2/18 levels following the Government of Alberta's announcement of mandatory curtailments of crude oil production that came into effect January 1, 2019.
- AECO natural gas prices decreased in Q2/19 from Q1/19 levels, primarily reflecting seasonal demand factors. AECO natural gas prices increased in Q2/19 from Q2/18 levels, primarily reflecting the easing of third party pipeline constraints to export markets.
- The North West Redwater ("NWR") refinery, upon completion, targets to strengthen the Company's position by providing a competitive return on investment and by creating incremental demand for approximately 80,000 bbl/d of heavy crude oil blends that will not require export pipelines, helping to reduce pricing volatility in all Western Canadian heavy crude oil.
  - The Company has a 50% interest in the NWR Partnership. For updates on the project, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.

FINANCIAL REVIEW

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

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production levels of 1,025,800 BOE/d in Q2/19, with approximately 97% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with Q2/19 production mix on a BOE/d basis of 51% light crude oil and SCO blends, 24% heavy crude oil blends and 25% natural gas.
- Canadian Natural delivered strong quarterly free cash flow of $1,295 million after net capital expenditures of $908 million, and dividend requirements of $449 million, excluding the Devon acquisition that closed on June 27, 2019, reflecting the strength of our long life low decline asset base and our effective and efficient operations.
- Balance sheet strength and strong financial performance was demonstrated in Q2/19 through the the repayment of C$500 million of 3.05% notes and reduction in long-term debt, excluding the Devon acquisition that closed on June 27, 2019.
  - In Q2/19, including the Devon acquisition, net long-term debt increased by $2,209 million to $23,109 million. Excluding financing related to the recently closed Devon acquisition, net long-term debt decreased by approximately $1,200 million from Q1/19 levels.
- In June 2019, the Company successfully executed on its funding plan for the acquisition through a $3,250 million, 3 year term facility.
- Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At June 30, 2019 the Company had approximately $4,560 million of available liquidity, including cash and cash equivalents, an increase of approximately $330 million over Q1/19 levels.
- Canadian Natural is committed to returns to shareholders, returning a total of $840 million in the quarter, $449 million by way of dividends and $391 million by way of share purchases. In the first half of 2019, the Company has returned a total of $1,484 million to shareholders, $852 million by way of dividends and $632 million by way of share purchases.
  - Share purchases for cancellation in the quarter totaled 10,450,000 common shares at a weighted average share price of $37.41.
  - Subsequent to quarter end, up to and including July 31, 2019, the Company executed on additional share purchases for cancellation of 2,300,000 common shares at a weighted average share price of $34.55.
  - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on October 1, 2019.
- In 2018, the Board of Directors approved a more defined free cash flow allocation policy in accordance with the Company's four stated pillars. Under the policy, in 2019 the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures, dividends and large opportunistic acquisitions, to share purchases under its NCIB and the remaining 50% to reducing debt levels on the Company's balance sheet. This free cash flow policy will target a ratio of debt to adjusted 12 months trailing EBITDA of 1.5x, and an absolute debt level of $15.0 billion, at which time the policy will be reviewed by the Board. This policy was effective November 1, 2018.
  - As previously announced, the Company renewed its NCIB for the 12 month period commencing on May 23, 2019 and ending May 22, 2020.
- In addition to the Company's strong adjusted funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at June 30, 2019, these financial levers include the Company's third party equity investments of $547 million, and cross currency swaps with a total value of $264 million.

- Subsequent to quarter end, in July 2019, 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 2021, replacing the Company's previous base shelf prospectuses which would have expired in August 2019. 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.

OUTLOOK

The Company targets annual 2019 production levels to average between 839,000 bbl/d and 888,000 bbl/d of crude oil and NGLs and between 1,485 MMcf/d and 1,545 MMcf/d of natural gas, before royalties. Q3/19 production guidance before royalties is targeted to average between 897,000 bbl/d and 939,000 bbl/d of crude oil and NGLs and between 1,440 MMcf/d and 1,460 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

Canadian Natural's annual 2019 capital expenditures are targeted to be approximately $3.8 billion.

ADVISORY

Special Note Regarding Non-GAAP and other Financial Measures

This press release includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; free cash flow; debt to adjusted EBITDA; debt to cash flow; available liquidity. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures and other financial measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, cash flows from operating activities, cash flows used in investing activities, and cash flows used in financing activities as determined in accordance with IFRS, as an indication of the Company's performance.

Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non- operational nature. The Company considers adjusted net earnings (loss) 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. The reconciliation "Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)" is presented in the Company's MD&A.

Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in the Company's MD&A.

Net capital expenditures is a non-GAAP 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, investment in other long-term assets, share consideration in business acquisitions and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the Net Capital Expenditures section of the Company's MD&A.

Free cash flow is a non-GAAP 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 from operating activities, abandonment, certain movements in other long-term assets, less net 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.

Adjusted EBITDA is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for interest, taxes, depletion, depreciation and amortization, stock based compensation expense (recovery), unrealized risk management gains (losses), unrealized foreign exchange gains (losses), and accretion of the Company's asset retirement obligation. The Company considers adjusted EBITDA a key measure in evaluating its operating profitability by excluding non-cash items.

Debt to Adjusted EBITDA is a non-GAAP measure that is derived as the current and long-term portions of long-term debt, divided by the 12 month trailing Adjusted EBITDA, as defined above. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

Debt to cash flow is a non-GAAP measure that is derived as the current and long term portions of long-term debt, divided by the 12 month trailing adjusted funds flow, as defined above. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt

Available liquidity is a non-GAAP measure that is derived as cash and cash equivalents, total bank and term credit facilities, less amounts drawn on the bank and credit facilities including under the commercial paper program. The Company considers available liquidity a key measure in evaluating the sustainability of the Company's operations and ability to fund future growth. See note 8 - Long-term Debt in the Company's consolidated financial statements.

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” 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 guidance 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 but not limited to the Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the timing and future operations of 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, and the development and deployment of technology and technological innovations 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 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 which will, among other things, impact demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is 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; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; 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 resumption of 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 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; 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 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 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, 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 Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, cash flows from operating activities, and cash flows used in investing activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measure adjusted net earnings from operations is reconciled to net earnings, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and six months ended June 30, 2019 and the MD&A and the audited consolidated financial statements of the Company for the year ended December 31, 2018. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three and six months ended June 30, 2019 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Changes in the Company's accounting policies in accordance with IFRS, including the adoption of IFRS 16 "Leases" on January 1, 2019, are discussed in the "Changes in Accounting Policies" section of this MD&A. In accordance with the new "Leases" standard, comparative period balances in 2018 reported in this MD&A have not been restated.

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, 2019 in relation to the comparable periods in 2018 and the first quarter of 2019. 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, 2018, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com, provided that such guidance does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated July 31, 2019.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2019	Three Months Ended Mar 31 2019	Three Months Ended Jun 30 2018	Six Months Ended Jun 30 2019	Six Months Ended Jun 30 2018
Product sales (1)	**$ 5,931**	$ 5,541	$ 6,389	**$ 11,472**	$ 12,124
Crude oil and NGLs	**$ 5,597**	$ 5,082	$ 6,071	**$ 10,679**	$ 11,374
Natural gas	**$ 324**	$ 456	$ 318	**$ 780**	$ 750
Net earnings	**$ 2,831**	$ 961	$ 982	**$ 3,792**	$ 1,565
Per common share – basic	**$ 2.37**	$ 0.80	$ 0.80	**$ 3.17**	$ 1.28
– diluted	**$ 2.36**	$ 0.80	$ 0.80	**$ 3.16**	$ 1.27
Adjusted net earnings from operations (2)	**$ 1,042**	$ 838	$ 1,279	**$ 1,880**	$ 2,164
Per common share – basic	**$ 0.87**	$ 0.70	$ 1.05	**$ 1.57**	$ 1.77
– diluted	**$ 0.87**	$ 0.70	$ 1.04	**$ 1.57**	$ 1.76
Cash flows from operating activities	**$ 2,861**	$ 996	$ 2,613	**$ 3,857**	$ 5,082
Adjusted funds flow (3)	**$ 2,652**	$ 2,240	$ 2,706	**$ 4,892**	$ 5,029
Per common share – basic	**$ 2.22**	$ 1.87	$ 2.20	**$ 4.09**	$ 4.10
– diluted	**$ 2.22**	$ 1.86	$ 2.19	**$ 4.08**	$ 4.08
Cash flows used in investing activities	**$ 4,464**	$ 1,029	$ 1,138	**$ 5,493**	$ 2,507
Net capital expenditures (4)	**$ 4,125**	$ 977	$ 974	**$ 5,102**	$ 2,077

(1) Further details related to product sales, including 'Other' income, for the three and six months ended June 30, 2019 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

(2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings as presented in the Company's consolidated Statements of Earnings, adjusted for the after-tax effects of certain items of a non-operational nature. 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. The reconciliation "Adjusted Net Earnings from Operations, as Reconciled to Net Earnings" is presented in this MD&A. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(3) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. 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. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(4) Net capital expenditures is a non-GAAP 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, investment in other long-term assets, share consideration in business combinations and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations, as Reconciled to Net Earnings

($ millions)	Three Months Ended **Jun 30 2019**	 Mar 31 2019	 Jun 30 2018	Six Months Ended **Jun 30 2019**	 Jun 30 2018
Net earnings	**$ 2,831**	$ 961	$ 982	**$ 3,792**	$ 1,565
Share-based compensation, net of tax (1)	**(7)**	62	175	**55**	87
Unrealized risk management (gain) loss, net of tax (2)	**(13)**	13	(11)	**—**	(42)
Unrealized foreign exchange (gain) loss, net of tax (3)	**(219)**	(233)	178	**(452)**	340
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**—**	—	—	**—**	146
Loss from investments, net of tax (5) (6)	**68**	35	38	**103**	151
Gain on acquisition and revaluation of properties (7)	**—**	—	(83)	**—**	(83)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**(1,618)**	—	—	**(1,618)**	—
Adjusted net earnings from operations	**$ 1,042**	$ 838	$ 1,279	**$ 1,880**	$ 2,164

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.

(2) Derivative financial instruments are recorded 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.

(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.

(4) During the first quarter of 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

(5) The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash loss from investments is the Company's pro rata share of the Redwater Partnership's equity loss for the period.

(6) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are measured each period with changes in fair value recognized in net earnings.

(7) During the second quarter of 2018, the Company recorded a pre-tax gain of $120 million ($72 million after-tax) on the acquisition of the remaining interest at Ninian in the North Sea and a pre-tax gain of $19 million ($11 million after-tax) relating to the revaluation of the Company's previously held interest at Ninian.

(8) In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with further 1% rate reductions every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities (1)

($ millions)	Three Months Ended **Jun 30 2019**	 Mar 31 2019	 Jun 30 2018	Six Months Ended **Jun 30 2019**	 Jun 30 2018
Cash flows from operating activities	**$ 2,861**	$ 996	$ 2,613	**$ 3,857**	$ 5,082
Net change in non-cash working capital	**(230)**	1,016	57	**786**	(178)
Abandonment expenditures (2)	**41**	108	50	**149**	140
Other (3)	**(20)**	120	(14)	**100**	(15)
Adjusted funds flow	**$ 2,652**	$ 2,240	$ 2,706	**$ 4,892**	$ 5,029

(1) Adjusted funds flow was previously referred to as funds flow from operations.

(2) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A.

(3) Movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the six months ended June 30, 2019 were $3,792 million compared with net earnings of $1,565 million for the six months ended June 30, 2018. Net earnings for the six months ended June 30, 2019 included net after-tax income of $1,912 million compared with net after-tax expenses of $599 million for the six months ended June 30, 2018 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, the loss from investments, the gain on acquisition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2019 were $1,880 million compared with adjusted net earnings from operations of $2,164 million for the six months ended June 30, 2018.

Net earnings for the second quarter of 2019 were $2,831 million compared with net earnings of $982 million for the second quarter of 2018 and net earnings of $961 million for the first quarter of 2019. Net earnings for the second quarter of 2019 included net after-tax income of $1,789 million compared with net after-tax expenses of $297 million for the second quarter of 2018 and net after-tax income of $123 million for the first quarter of 2019 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss from investments, the gain on acquisition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the second quarter of 2019 were $1,042 million compared with adjusted net earnings from operations of $1,279 million for the second quarter of 2018 and adjusted net earnings from operations of $838 million for the first quarter of 2019.

Net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2019 compared with the three and six months ended June 30, 2018 primarily reflected:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher realized risk management losses;

partially offset by:

- higher crude oil and NGLs netbacks in the Exploration and Production segments;
- higher crude oil and NGLs sales volumes in the Offshore Africa segment; and
- higher natural gas netbacks in the North America Exploration and Production segment.

Net earnings and adjusted net earnings from operations for the second quarter of 2019 compared with the first quarter of 2019 primarily reflected:

- higher crude oil and NGLs sales volumes in the Exploration and Production segments; and
- higher crude oil and NGLs netbacks in the Exploration and Production segments;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- lower natural gas netbacks in the Exploration and Production segments.

Net earnings for the three and six months ended June 30, 2019 also reflected the Government of Alberta enacted decrease in the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with further 1% rate reductions every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. This resulted in a decrease in the Company's deferred corporate income tax liability by $1,618 million. See the "Income Taxes" section of this MD&A.

For the three and six months ended June 30, 2019, the adoption of IFRS 16 did not have a significant overall impact on net earnings and adjusted net earnings from operations. The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings for the three and six months ended June 30, 2019 from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the six months ended June 30, 2019 were $3,857 million compared with $5,082 million for the six months ended June 30, 2018. Cash flows from operating activities for the second quarter of 2019 were $2,861 million compared with $2,613 million for the second quarter of 2018 and $996 million for the first quarter of 2019. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors noted above relating to the fluctuations in net earnings and adjusted net earnings from operations (excluding the effects of depletion, depreciation and amortization and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the six months ended June 30, 2019 were $4,892 million compared with $5,029 million for the six months ended June 30, 2018. Adjusted funds flow for the second quarter of 2019 were $2,652 million compared with $2,706 million for the second quarter of 2018 and $2,240 million for the first quarter of 2019. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Cash flows from operating activities and adjusted funds flow for the six months ended June 30, 2019 reflected an increase of $109 million related to the adoption of IFRS 16 on January 1, 2019. The adoption of IFRS 16 is discussed in the "Changes in Accounting Policies" section of this MD&A.

Production Volumes

Total production before royalties for the second quarter of 2019 decreased 2% to 1,025,800 BOE/d from 1,050,376 BOE/d for the second quarter of 2018 and was comparable with 1,035,212 BOE/d for the first quarter of 2019. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section 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 2019**		Mar 31 2019		Dec 31 2018		Sep 30 2018
Product sales [1]	**$**	**5,931**	$	5,541	$	3,831	$	6,327
Crude oil and NGLs	**$**	**5,597**	$	5,082	$	3,327	$	5,967
Natural gas	**$**	**324**	$	456	$	504	$	360
Net earnings (loss)	**$**	**2,831**	$	961	$	(776)	$	1,802
Net earnings (loss) per common share								
– basic	**$**	**2.37**	$	0.80	$	(0.64)	$	1.48
– diluted	**$**	**2.36**	$	0.80	$	(0.64)	$	1.47
($ millions, except per common share amounts)		Jun 30 2018		Mar 31 2018		Dec 31 2017		Sep 30 2017
Product sales	$	6,389	$	5,735	$	5,516	$	4,725
Crude oil and NGLs	$	6,071	$	5,303	$	5,098	$	4,320
Natural gas	$	318	$	432	$	418	$	405
Net earnings (loss)	$	982	$	583	$	396	$	684
Net earnings (loss) per common share								
– basic	$	0.80	$	0.48	$	0.32	$	0.56
– diluted	$	0.80	$	0.47	$	0.32	$	0.56

(1) Further details related to product sales, including 'Other' income, for the three months ended June 30, 2019 are disclosed in note 17 to the Company’s unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries (“OPEC”) and its impact on world supply, the impact of geopolitical uncertainties 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 including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"), the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect January 1, 2019.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company’s Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the impact of the Company’s drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon Canada Corporation ("Devon") in the second quarter of 2019, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production in late 2018 due to low commodity prices in North America and production curtailments mandated by the Government of Alberta that came into effect January 1, 2019. 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 allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at the Pine River processing facility, shut-in production due to third-party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs that are dependent on weather, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, maintenance activities in the International segments and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Depletion, depreciation and amortization** – 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 the impact of the adoption of IFRS 16 on January 1, 2019.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model 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.
- **Foreign exchange rates** – 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. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) on the Company's interest in the Redwater Partnership.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended Jun 30 2019	Three Months Ended Mar 31 2019	Three Months Ended Jun 30 2018	Six Months Ended Jun 30 2019	Six Months Ended Jun 30 2018
WTI benchmark price (US$/bbl)	**$ 59.83**	$ 54.90	$ 67.90	**$ 57.38**	$ 65.41
Dated Brent benchmark price (US$/bbl)	**$ 68.36**	$ 63.34	$ 74.51	**$ 65.87**	$ 70.77
WCS heavy differential from WTI (US$/bbl)	**$ 10.65**	$ 12.38	$ 19.24	**$ 11.51**	$ 21.74
SCO price (US$/bbl)	**$ 59.96**	$ 52.19	$ 67.27	**$ 56.10**	$ 64.38
Condensate benchmark price (US$/bbl)	**$ 55.86**	$ 50.49	$ 68.85	**$ 53.19**	$ 66.00
Condensate differential from WTI (US$/bbl)	**$ 3.96**	$ 4.40	$ (0.95)	**$ 4.18**	$ (0.59)
NYMEX benchmark price (US$/MMBtu)	**$ 2.64**	$ 3.16	$ 2.80	**$ 2.89**	$ 2.89
AECO benchmark price (C$/GJ)	**$ 1.11**	$ 1.84	$ 0.97	**$ 1.47**	$ 1.36
US/Canadian dollar average exchange rate (US$)	**$ 0.7474**	$ 0.7522	$ 0.7746	**$ 0.7498**	$ 0.7824

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 Alberta 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 highly sensitive to fluctuations in foreign exchange rates. Product revenue continued to be impacted by the volatility in 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.

Effective January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. While the timing of cessation of the program remains uncertain, the Company currently anticipates curtailments to continue through the end of 2019. The Company continues to execute operational flexibility to maximize production volumes through its curtailment optimization strategy, and has significant additional capacity available to further increase production volumes should curtailment restrictions ease.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$57.38 per bbl for the six months ended June 30, 2019, a decrease of 12% from US$65.41 per bbl for the six months ended June 30, 2018. WTI averaged US$59.83 per bbl for the second quarter of 2019, a decrease of 12% from US$67.90 per bbl for the second quarter of 2018, and an increase of 9% from US$54.90 per bbl for the first quarter of 2019.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$65.87 per bbl for the six months ended June 30, 2019, a decrease of 7% from US$70.77 per bbl for the six months ended June 30, 2018. Brent averaged US$68.36 per bbl for the second quarter of 2019, a decrease of 8% from US$74.51 per bbl for the second quarter of 2018, and an increase of 8% from US$63.34 per bbl for the first quarter of 2019.

WTI and Brent pricing for the three and six months ended June 30, 2019 has decreased from the comparable periods in 2018 primarily due to increases in global crude oil supply, primarily due to increasing shale oil production in the US. The increase in WTI and Brent pricing for the second quarter of 2019 as compared with the first quarter of 2019 reflected the extension of OPEC's previously announced production cuts along with decreased production from Russia.

The WCS heavy differential averaged US$11.51 per bbl for the six months ended June 30, 2019, a decrease of 47% from US$21.74 per bbl for the six months ended June 30, 2018. The WCS heavy differential averaged US$10.65 per bbl for the second quarter of 2019, a decrease of 45% from US$19.24 per bbl for the second quarter of 2018, and a decrease of 14% from US$12.38 per bbl for the first quarter of 2019. The narrowing of the WCS heavy differential for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

The SCO price averaged US$56.10 per bbl for the six months ended June 30, 2019, a decrease of 13% from US$64.38 per bbl for the six months ended June 30, 2018. The SCO price averaged US$59.96 per bbl for the second quarter of 2019, a decrease of 11% from US$67.27 per bbl for the second quarter of 2018, and an increase of 15% from US$52.19 per bbl for the first quarter of 2019. The fluctuations in the SCO price for the three and six months ended June 30, 2019 from the comparable periods primarily reflected movements in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.89 per MMBtu for the six months ended June 30, 2019, comparable with US$2.89 per MMBtu for the six months ended June 30, 2018. NYMEX natural gas prices averaged US$2.64 per MMBtu for the second quarter of 2019, a decrease of 6% from US$2.80 per MMBtu for the second quarter of 2018, and a decrease of 16% from US$3.16 per MMBtu for the first quarter of 2019. The decrease in NYMEX natural gas prices for the second quarter of 2019 as compared with the second quarter of 2018 reflected increased natural gas supply in North America, resulting in third-party pipeline constraints into the Gulf region and other regional hubs. The decrease in NYMEX natural gas prices for the second quarter of 2019 as compared with the first quarter of 2019 reflected seasonal demand factors.

AECO natural gas prices averaged $1.47 per GJ for the six months ended June 30, 2019, an increase of 8% from $1.36 per GJ for the six months ended June 30, 2018. AECO natural gas prices averaged $1.11 per GJ for the second quarter of 2019, an increase of 14% from $0.97 per GJ for the second quarter of 2018, and a decrease of 40% from $1.84 per GJ for the first quarter of 2019. The increase in AECO natural gas prices for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected the easing of third-party pipeline constraints to export markets. The decrease in AECO natural gas prices for the second quarter of 2019 as compared with the first quarter of 2019 primarily reflected seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**344,665**	319,437	343,538	**332,120**	350,460
North America – Oil Sands Mining and Upgrading [1]	**374,500**	416,206	407,704	**395,238**	431,756
North Sea	**27,594**	25,714	24,456	**26,659**	23,028
Offshore Africa	**23,650**	22,155	18,201	**22,907**	18,816
	770,409	783,512	793,899	**776,924**	824,060
Natural gas (MMcf/d)					
North America	**1,482**	1,454	1,485	**1,468**	1,515
North Sea	**23**	28	30	**25**	34
Offshore Africa	**27**	28	24	**28**	27
	1,532	1,510	1,539	**1,521**	1,576
Total barrels of oil equivalent (BOE/d)	**1,025,800**	1,035,212	1,050,376	**1,030,480**	1,086,757
Product mix					
Light and medium crude oil and NGLs	**15%**	14%	13%	**14%**	12%
Pelican Lake heavy crude oil	**5%**	6%	6%	**6%**	6%
Primary heavy crude oil	**8%**	7%	8%	**7%**	8%
Bitumen (thermal oil)	**11%**	9%	10%	**10%**	10%
Synthetic crude oil	**36%**	40%	39%	**38%**	40%
Natural gas	**25%**	24%	24%	**25%**	24%
Percentage of gross revenue [1] [2] (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**95%**	91%	95%	**93%**	94%
Natural gas	**5%**	9%	5%	**7%**	6%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**307,413**	281,233	293,080	**294,395**	301,883
North America – Oil Sands Mining and Upgrading	**354,975**	397,639	385,986	**376,189**	414,171
North Sea	**27,525**	25,675	24,411	**26,605**	22,974
Offshore Africa	**22,694**	20,260	16,502	**21,484**	17,571
	712,607	724,807	719,979	**718,673**	756,599
Natural gas (MMcf/d)					
North America	**1,427**	1,399	1,407	**1,414**	1,439
North Sea	**23**	28	30	**25**	34
Offshore Africa	**25**	25	20	**25**	23
	1,475	1,452	1,457	**1,464**	1,496
Total barrels of oil equivalent (BOE/d)	**958,499**	966,758	962,742	**962,605**	1,006,012

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 for the six months ended June 30, 2019 decreased 6% to 776,924 bbl/d from 824,060 bbl/d for the six months ended June 30, 2018. Crude oil and NGLs production for the second quarter of 2019 of 770,409 bbl/d decreased 3% from 793,899 bbl/d for the second quarter of 2018, and was comparable with 783,512 bbl/d for the first quarter of 2019. The decrease in crude oil and NGLs production for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected unplanned maintenance activities at Horizon, maintenance activities and repairs related to the fire at the Scotford Upgrader, as well as the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019. The Company continues to optimize its production volumes across the asset base during curtailment. During the second quarter of 2019, the Company increased production of thermal and conventional oil which partially offset the impact of lower SCO production.

Second quarter 2019 crude oil and NGLs production was slightly below the Company's previously issued guidance of 773,000 to 831,000 bbl/d. Third quarter 2019 crude oil and NGLs production guidance is targeted to average between 897,000 and 939,000 bbl/d, reflecting known production curtailments mandated by the Government of Alberta through September 2019 and the strategic allocation of curtailment volumes across various assets as a result of the 25 day turnaround commencing mid-September 2019 at Horizon. Annual crude oil and NGLs production guidance for 2019 is now targeted to average between 839,000 and 888,000 bbl/d.

Natural gas production for the six months ended June 30, 2019 decreased 3% to 1,521 MMcf/d from 1,576 MMcf/d for the six months ended June 30, 2018. Natural gas production for the second quarter of 2019 averaged 1,532 MMcf/d, comparable with 1,539 MMcf/d for the second quarter of 2018, and 1,510 MMcf/d for the first quarter of 2019. Natural gas production for the three and six months ended June 30, 2019 primarily reflected associated gas production from light crude oil and liquids rich natural gas drilling, partially offset by natural field declines.

Second quarter 2019 natural gas production exceeded the Company's previously issued guidance of 1,500 to 1,530 MMcf/d. Third quarter 2019 natural gas production guidance is targeted to average between 1,440 and 1,460 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2019 averaged 332,120 bbl/d, a decrease of 5% from 350,460 bbl/d for the six months ended June 30, 2018. North America crude oil and NGLs production for the second quarter of 2019 of 344,665 bbl/d was comparable with 343,538 bbl/d for the second quarter of 2018, and increased 8% from 319,437 bbl/d for the first quarter of 2019. The decrease in production for the six months ended June 30, 2019 from the six months ended June 30, 2018 primarily reflected the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019. The increase in production for the second quarter of 2019 from the first quarter of 2019 reflected increased production of thermal and conventional oil to optimize curtailment volumes across the Company's asset base. Crude oil and NGLs production in the second quarter of 2019 also reflected additional volumes from the acquisition of assets from Devon that closed on June 27, 2019.

Pelican Lake heavy crude oil production averaged 55,031 bbl/d for the second quarter of 2019 compared with 63,914 bbl/d for the second quarter of 2018 and 61,240 bbl/d for the first quarter of 2019, reflecting the temporary shut-in of crude oil production from May 30, 2019 to June 8, 2019 due to wildfires in northern Alberta. In July 2019, heavy crude oil production at Pelican Lake averaged approximately 62,000 bbl/d.

Overall thermal oil production for the second quarter of 2019 averaged 109,599 bbl/d compared with 104,907 bbl/d for the second quarter of 2018 and 94,146 bbl/d for the first quarter of 2019, reflecting increased production of thermal oil to optimize curtailment volumes across the Company's asset base. Thermal oil production in the second quarter of 2019 also reflected additional volumes from the acquisition of assets from Devon that closed on June 27, 2019. Second quarter 2019 thermal oil production exceeded the Company's previously issued guidance of 100,000 to 106,000 bbl/d. Third quarter 2019 thermal oil production guidance is targeted to average between 198,000 and 206,000 bbl/d, reflecting known production curtailments mandated by the Government of Alberta through September 2019. Annual thermal oil production guidance for 2019 is now targeted to average between 157,000 and 172,000 bbl/d.

Second quarter 2019 crude oil and NGLs production, including thermal oil, exceeded the Company's previously issued guidance of 324,000 to 338,000 bbl/d. Third quarter 2019 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 440,000 and 458,000 bbl/d, reflecting known production curtailments mandated by the Government of Alberta through September 2019. Annual crude oil and NGLs production guidance for 2019, including thermal oil, is now targeted to average between 388,000 and 423,000 bbl/d.

Natural gas production for the six months ended June 30, 2019 decreased 3% to 1,468 MMcf/d from 1,515 MMcf/d for the six months ended June 30, 2018. Natural gas production for the second quarter of 2019 averaged 1,482 MMcf/d, comparable with 1,485 MMcf/d for the second quarter of 2018, and 1,454 MMcf/d for the first quarter of 2019. Natural gas production for the three and six months ended June 30, 2019 primarily reflected associated gas production from light crude oil and liquids rich natural gas drilling, partially offset by natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production for the six months ended June 30, 2019 of 395,238 bbl/d decreased 8% from 431,756 bbl/d for the six months ended June 30, 2018. SCO production for the second quarter of 2019 decreased 8% to average 374,500 bbl/d from 407,704 bbl/d for the second quarter of 2018 and decreased 10% from 416,206 bbl/d for the first quarter of 2019. The decrease in production for the three and six months ended June 30, 2019 from the comparable periods primarily reflected unplanned maintenance activities at Horizon, maintenance activities and repairs related to the fire at the Scotford Upgrader, and to a lesser extent, the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Second quarter 2019 SCO production was below the Company's previously issued guidance of 400,000 to 440,000 bbl/d. Third quarter 2019 SCO production guidance is targeted to average between 413,000 and 433,000 bbl/d, reflecting the 25 day turnaround commencing mid-September 2019 at Horizon. Annual SCO production guidance for 2019 is now targeted to average between 405,000 and 415,000 bbl/d.

North Sea

North Sea crude oil production for the six months ended June 30, 2019 of 26,659 bbl/d increased 16% from 23,028 bbl/d for the six months ended June 30, 2018. North Sea crude oil production for the second quarter of 2019 increased 13% to 27,594 bbl/d from 24,456 bbl/d for the second quarter of 2018 and increased 7% from 25,714 bbl/d for the first quarter of 2019. The increase in production for the three and six months ended June 30, 2019 from the comparable periods primarily reflected volumes from new wells, partially offset by the impact of the planned turnaround at Ninian and natural field declines.

Offshore Africa

Offshore Africa crude oil production for the six months ended June 30, 2019 increased 22% to 22,907 bbl/d from 18,816 bbl/d for the six months ended June 30, 2018. Offshore Africa crude oil production for the second quarter of 2019 of 23,650 bbl/d increased 30% from 18,201 bbl/d for the second quarter of 2018 and increased 7% from 22,155 bbl/d for the first quarter of 2019. The increase in production for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected volumes from new wells drilled in 2018 and the first quarter of 2019 at Baobab, partially offset by the cessation of production at the Olowi field in December 2018 and natural field declines. The increase in production for the second quarter of 2019 from the first quarter of 2019 reflected volumes from new wells drilled in 2018 and the first quarter of 2019 at Baobab, partially offset by natural field declines.

International Guidance

Second quarter 2019 International crude oil production of 51,244 bbl/d was within the Company's previously issued guidance of 49,000 to 53,000 bbl/d. Third quarter 2019 International crude oil production guidance is targeted to average between 44,000 and 48,000 bbl/d, reflecting planned turnarounds in the North Sea and Offshore Africa. Annual International crude oil production guidance for 2019 is now targeted to average between 46,000 and 50,000 bbl/d.

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 business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

(bbl)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018
North Sea	**969,651**	851,919	297,217
Offshore Africa	**1,076,772**	1,055,383	1,466,074
	2,046,423	1,907,302	1,763,291

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 63.45**	$ 53.98	$ 61.14	**$ 59.05**	$ 52.32
Transportation	**3.35**	3.26	3.30	**3.31**	3.20
Realized sales price, net of transportation	**60.10**	50.72	57.84	**55.74**	49.12
Royalties	**6.35**	5.95	7.56	**6.17**	6.25
Production expense	**14.42**	16.04	15.64	**15.17**	15.67
Netback	**$ 39.33**	$ 28.73	$ 34.64	**$ 34.40**	$ 27.20
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 1.98**	$ 3.09	$ 1.95	**$ 2.53**	$ 2.35
Transportation	**0.40**	0.46	0.51	**0.43**	0.50
Realized sales price, net of transportation	**1.58**	2.63	1.44	**2.10**	1.85
Royalties	**0.08**	0.12	0.08	**0.10**	0.09
Production expense	**1.23**	1.33	1.39	**1.28**	1.40
Netback	**$ 0.27**	$ 1.18	$ (0.03)	**$ 0.72**	$ 0.36
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 43.38**	$ 39.27	$ 41.63	**$ 41.42**	$ 36.86
Transportation	**2.97**	3.06	3.20	**3.03**	3.13
Realized sales price, net of transportation	**40.41**	36.21	38.43	**38.39**	33.73
Royalties	**4.06**	3.78	4.75	**3.92**	3.93
Production expense	**11.68**	12.68	12.75	**12.15**	12.71
Netback	**$ 24.67**	$ 19.75	$ 20.93	**$ 22.32**	$ 17.09

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 59.45**	$ 50.92	$ 56.95	**$ 55.39**	$ 48.82
North Sea	**$ 88.25**	$ 87.61	$ 93.49	**$ 88.00**	$ 88.36
Offshore Africa	**$ 95.33**	$ 81.00	$ 102.57	**$ 89.79**	$ 94.17
Average	**$ 63.45**	$ 53.98	$ 61.14	**$ 59.05**	$ 52.32
Natural gas ($/Mcf) (1) (2)					
North America	**$ 1.84**	$ 2.88	$ 1.69	**$ 2.35**	$ 2.07
North Sea	**$ 5.34**	$ 10.05	$ 10.32	**$ 7.96**	$ 11.06
Offshore Africa	**$ 6.94**	$ 7.34	$ 7.37	**$ 7.14**	$ 7.14
Average	**$ 1.98**	$ 3.09	$ 1.95	**$ 2.53**	$ 2.35
Average ($/BOE) (1) (2)	**$ 43.38**	$ 39.27	$ 41.63	**$ 41.42**	$ 36.86

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

North America

North America realized crude oil prices increased 13% to $55.39 per bbl for the six months ended June 30, 2019 from $48.82 per bbl for the six months ended June 30, 2018. North America realized crude oil prices averaged $59.45 per bbl for the second quarter of 2019, an increase of 4% compared with $56.95 per bbl for the second quarter of 2018, and an increase of 17% compared with $50.92 per bbl for the first quarter of 2019. The increase in realized crude oil prices for the three and six months ended June 30, 2019 from the comparable periods in 2018 was primarily due to the narrowing of the WCS heavy differential as a result of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019. The increase in realized crude oil prices in the second quarter of 2019 from the first quarter of 2019 primarily reflected the increase in WTI pricing. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2019 contributed approximately 174,100 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 14% to average $2.35 per Mcf for the six months ended June 30, 2019 from $2.07 per Mcf for the six months ended June 30, 2018. North America realized natural gas prices increased 9% to average $1.84 per Mcf for the second quarter of 2019 compared with $1.69 per Mcf for the second quarter of 2018, and decreased 36% compared with $2.88 per Mcf for the first quarter of 2019. The increase in realized natural gas prices for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected the easing of third-party pipeline constraints to export markets. The decrease in realized natural gas prices for the second quarter of 2019 compared with the first quarter of 2018 primarily reflected seasonal demand factors.

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

	Three Months Ended		
(Quarterly Average)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 53.23**	$ 49.13	$ 62.06
Pelican Lake heavy crude oil ($/bbl)	**$ 66.71**	$ 56.28	$ 60.49
Primary heavy crude oil ($/bbl)	**$ 64.71**	$ 52.27	$ 56.33
Bitumen (thermal oil) ($/bbl)	**$ 57.61**	$ 48.27	$ 51.04
Natural gas ($/Mcf)	**$ 1.84**	$ 2.88	$ 1.69

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

North Sea

North Sea realized crude oil prices averaged $88.00 per bbl for the six months ended June 30, 2019, comparable with $88.36 per bbl for the six months ended June 30, 2018. North Sea realized crude oil prices decreased 6% to average $88.25 per bbl for the second quarter of 2019 from $93.49 per bbl for the second quarter of 2018 and was comparable with $87.61 per bbl for the first quarter of 2019. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2019 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 5% to average $89.79 per bbl for the six months ended June 30, 2019 from $94.17 per bbl for the six months ended June 30, 2018. Offshore Africa realized crude oil prices decreased 7% to average $95.33 per bbl for the second quarter of 2019 from $102.57 per bbl for the second quarter of 2018 and increased 18% from $81.00 per bbl for the first quarter of 2019. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2019 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 6.99**	$ 6.22	$ 8.03	**$ 6.62**	$ 6.57
North Sea	**$ 0.22**	$ 0.13	$ 0.17	**$ 0.18**	$ 0.19
Offshore Africa	**$ 3.85**	$ 6.93	$ 9.58	**$ 5.04**	$ 7.32
Average	**$ 6.35**	$ 5.95	$ 7.56	**$ 6.17**	$ 6.25
Natural gas ($/Mcf) [(1)]					
North America	**$ 0.07**	$ 0.11	$ 0.06	**$ 0.09**	$ 0.08
Offshore Africa	**$ 0.59**	$ 0.85	$ 1.17	**$ 0.72**	$ 1.00
Average	**$ 0.08**	$ 0.12	$ 0.08	**$ 0.10**	$ 0.09
Average ($/BOE) [(1)]	**$ 4.06**	$ 3.78	$ 4.75	**$ 3.92**	$ 3.93

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and natural gas royalties for the three and six months ended June 30, 2019 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 12% of product sales for the six months ended June 30, 2019 compared with 14% of product sales for the six months ended June 30, 2018. Crude oil and NGLs royalty rates averaged approximately 12% of product sales for the second quarter of 2019 compared with 15% for the second quarter of 2018 and 12% for the first quarter of 2019. The decrease in royalty rates for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected the impact of underlying changes in the benchmark prices together with fluctuations in the WCS heavy differential.

Natural gas royalty rates averaged approximately 4% of product sales for the six months ended June 30, 2019 compared with 5% of product sales for the six months ended June 30, 2018. Natural gas royalty rates averaged approximately 4% of product sales for the second quarter of 2019 compared with 5% for the second quarter of 2018 and 4% for the first quarter of 2019.

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 6% for the six months ended June 30, 2019, compared with 9% of product sales for the six months ended June 30, 2018. Royalty rates as a percentage of product sales averaged approximately 4% for the second quarter of 2019, compared with 10% of product sales for the second quarter of 2018 and 9% for the first quarter of 2019. 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 2019	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 13.10**	$ 15.07	$ 13.78	**$ 14.03**	$ 13.96
North Sea	**$ 37.31**	$ 39.68	$ 35.12	**$ 38.24**	$ 38.12
Offshore Africa	**$ 8.40**	$ 9.79	$ 24.78	**$ 8.93**	$ 26.98
Average	**$ 14.42**	$ 16.04	$ 15.64	**$ 15.17**	$ 15.67
Natural gas ($/Mcf) [1]					
North America	**$ 1.15**	$ 1.30	$ 1.28	**$ 1.22**	$ 1.29
North Sea [2]	**$ 5.09**	$ 2.41	$ 5.81	**$ 3.60**	$ 5.18
Offshore Africa [2]	**$ 2.49**	$ 2.12	$ 3.00	**$ 2.30**	$ 2.69
Average	**$ 1.23**	$ 1.33	$ 1.39	**$ 1.28**	$ 1.40
Average ($/BOE) [1]	**$ 11.68**	$ 12.68	$ 12.75	**$ 12.15**	$ 12.71

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) North Sea and Offshore Africa natural gas production expense for the six months ended June 30, 2019 reflected a decrease of $12 million ($2.61 per Mcf) and $2 million ($0.48 per Mcf) respectively, related to the adoption of IFRS 16.

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2019 of $14.03 per bbl was comparable with $13.96 per bbl for the six months ended June 30, 2018. North America crude oil and NGLs production expense for the second quarter of 2019 of $13.10 per bbl decreased 5% from $13.78 per bbl for the second quarter of 2018 and decreased 13% from $15.07 per bbl for the first quarter of 2019. The decrease in crude oil and NGLs production expense per barrel for the second quarter of 2019 from the second quarter of 2018 primarily reflected lower labour and service costs. The decrease in production expense per barrel for the second quarter of 2019 from the first quarter of 2019 reflected the impact of higher volumes on a relatively fixed cost base, together with lower fuel, power and communication costs, partially offset by higher lease maintenance and trucking costs. The Company continues to focus on cost control and achieving efficiencies across the entire asset base.

North America crude oil and NGLs production expense for the six months ended June 30, 2019 reflected a decrease of $10 million ($0.16 per bbl) related to the adoption of IFRS 16.

North America natural gas production expense for the six months ended June 30, 2019 averaged $1.22 per Mcf, a decrease of 5% from $1.29 per Mcf for the six months ended June 30, 2018. North America natural gas production expense for the second quarter of 2019 of $1.15 per Mcf decreased 10% from $1.28 per Mcf for the second quarter of 2018 and decreased 12% from $1.30 per Mcf for the first quarter of 2019. The decrease in production expense for the three and six months ended June 30, 2019 from the comparable periods primarily reflected the Company's continuous focus on cost control and achieving efficiencies across the entire asset base together with the impact of increased volumes processed in strategically owned and operated infrastructure.

North America natural gas production expense for the six months ended June 30, 2019 reflected a decrease of $2 million ($0.01 per Mcf) related to the adoption of IFRS 16.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2019 of $38.24 per bbl was comparable with $38.12 per bbl for the six months ended June 30, 2018. North Sea crude oil production expense of $37.31 per bbl for the second quarter of 2019 increased 6% from $35.12 per bbl for the second quarter of 2018 and decreased 6% from $39.68 per bbl for the first quarter of 2019. The increase in crude oil production expense for the second quarter of 2019 from the second quarter of 2018 primarily reflected the impact of additional costs associated with the planned turnaround at Ninian in the second quarter of 2019 and the timing of liftings from various fields that have different cost structures, partially offset by the impact of IFRS 16. The decrease in production expense for the second quarter of 2019 from the first quarter of 2019 primarily reflected the timing of liftings from certain fields, offsetting the impact of turnaround costs at Ninian incurred during the second quarter of 2019. Production expense is also impacted by fluctuations in the Canadian dollar.

North Sea crude oil production expense for the six months ended June 30, 2019 reflected a decrease of $9 million ($2.24 per bbl) related to the adoption of IFRS 16.

Offshore Africa

Offshore Africa crude oil production expense for the six months ended June 30, 2019 was $8.93 per bbl compared with $26.98 per bbl for the six months ended June 30, 2018. Offshore Africa crude oil production expense for the second quarter of 2019 averaged $8.40 per bbl compared with $24.78 per bbl for the second quarter of 2018 and $9.79 per bbl for the first quarter of 2019. Crude oil production expense in 2019 reflected the cessation of production at the Olowi field, Gabon in December 2018.

The fluctuations in crude oil production expense for the three and six months ended June 30, 2019 from the comparable periods also reflected the timing of liftings from various fields, that have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

Offshore Africa crude oil production expense for the six months ended June 30, 2019 reflected a decrease of $6 million ($1.75 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Expense	**$ 929**	$ 843	$ 894	**$ 1,772**	$ 1,744
$/BOE (1)	**$ 15.60**	$ 15.54	$ 15.20	**$ 15.58**	$ 14.93

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization expense per BOE for the six months ended June 30, 2019 increased 4% to $15.58 per BOE from $14.93 per BOE for the six months ended June 30, 2018. Depletion, depreciation and amortization expense per BOE for the second quarter of 2019 increased 3% to $15.60 per BOE from $15.20 per BOE for the second quarter of 2018 and was comparable with $15.54 per BOE for the first quarter of 2019.

The increase in depletion, depreciation and amortization expense per BOE for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected the adoption of IFRS 16, partially offset by lower depletion rates in Offshore Africa and North America in 2019. Depletion, depreciation and amortization expense for the six months ended June 30, 2019 reflected an increase of $77 million ($0.68 per BOE) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Expense	**$ 31**	$ 28	$ 32	**$ 59**	$ 63
$/BOE (1)	**$ 0.49**	$ 0.54	$ 0.53	**$ 0.52**	$ 0.53

(1) Amounts expressed on a per unit basis are based on 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 per BOE for the six months ended June 30, 2019 decreased 2% to $0.52 per BOE from $0.53 per BOE for the six months ended June 30, 2018. Asset retirement obligation accretion expense for the second quarter of 2019 decreased 8% to $0.49 per BOE from $0.53 per BOE for the second quarter of 2018, and decreased 9% from $0.54 per BOE for the first quarter of 2019.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the sites. Production in the second quarter of 2019 averaged 374,500 bbl/d, reflecting planned and unplanned maintenance activities at Horizon and at the Scotford Upgrader, as well as the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019. At the Scotford Upgrader, maintenance activities and repairs related to the fire were successfully completed, with operations at full production on June 24, 2019.

Through continuous focus on cost control and efficiencies, the Company has achieved quarterly production costs of $814 million, comparable with the first quarter of 2019 and a 5% decrease from the second quarter of 2018, notwithstanding planned and unplanned maintenance activities during the quarter.

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

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
SCO realized sales price (2)	**$ 74.98**	$ 65.86	$ 80.17	**$ 70.12**	$ 75.70
Bitumen value for royalty purposes (3)	**$ 58.74**	$ 48.16	$ 49.10	**$ 53.16**	$ 39.94
Bitumen royalties (4)	**$ 3.79**	$ 2.31	$ 4.25	**$ 3.00**	$ 3.06
Transportation	**$ 1.53**	$ 1.17	$ 1.63	**$ 1.34**	$ 1.59

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

(2) Net of blending and feedstock costs.

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

(4) Calculated based on bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $70.12 per bbl for the six months ended June 30, 2019, a decrease of 7% from $75.70 per bbl for the six months ended June 30, 2018. For the second quarter of 2019, the realized sales price decreased 6% to $74.98 per bbl from $80.17 per bbl for the second quarter of 2018 and increased 14% from $65.86 per bbl for the first quarter of 2019. The fluctuations in the realized SCO sales price for the three and six months ended June 30, 2019 from the comparable periods primarily reflected movements in WTI benchmark pricing.

Transportation expense for the Oil Sands Mining and Upgrading segment averaged $1.34 per bbl for the six months ended June 30, 2019, compared with $1.59 per bbl for the six months ended June 30, 2018. Transportation expense averaged $1.53 per bbl for the second quarter of 2019, compared with $1.63 per bbl for the second quarter of 2018 and $1.17 per bbl for the first quarter of 2019. Transportation expense for the six months ended June 30, 2019 reflected a decrease of $33 million ($0.46 per bbl) related to the adoption of IFRS 16.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Production costs, excluding natural gas costs	**$ 789**	$ 779	$ 834	**$ 1,568**	$ 1,669
Natural gas costs	**25**	43	21	**68**	59
Production costs	**$ 814**	$ 822	$ 855	**$ 1,636**	$ 1,728

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Production costs, excluding natural gas costs	**$ 23.45**	$ 20.33	$ 22.37	**$ 21.79**	$ 21.36
Natural gas costs	**0.72**	1.13	0.57	**0.94**	0.76
Production costs	**$ 24.17**	$ 21.46	$ 22.94	**$ 22.73**	$ 22.12
Sales (bbl/d)	**369,846**	425,790	409,603	**397,664**	431,604

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Production costs for the six months ended June 30, 2019 increased 3% to $22.73 per bbl from $22.12 per bbl for the six months ended June 30, 2018. Production costs for the second quarter of 2019 averaged $24.17 per bbl, an increase of 5% from $22.94 per bbl for the second quarter of 2018 and an increase of 13% from $21.46 per bbl for the first quarter of 2019.

Production costs for the three and six months ended June 30, 2019 reflected the Company's continuous focus on cost control and efficiencies. Production costs per barrel during the second quarter of 2019 included the impact of maintenance activities and extended time for repairs related to the fire at the Scotford Upgrader and proactive maintenance at Horizon, resulting in lower volumes in the period. Production costs in the second quarter of 2019 as compared with the first quarter of 2019 also reflected lower fuel costs. Production costs for the six months ended June 30, 2019 reflected a decrease of $12 million ($0.17 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Expense	**$ 374**	$ 417	$ 372	**$ 791**	$ 776
$/bbl (1)	**$ 11.12**	$ 10.88	$ 9.99	**$ 10.99**	$ 9.93

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Depletion, depreciation and amortization expense per bbl for the Oil Sands Mining and Upgrading segment for the six months ended June 30, 2019 increased 11% to $10.99 per bbl from $9.93 per bbl for the six months ended June 30, 2018. Depletion, depreciation and amortization expense per bbl for the second quarter of 2019 of $11.12 per bbl increased 11% from $9.99 per bbl for the second quarter of 2018, and increased 2% from $10.88 per bbl for the first quarter of 2019.

The increase in depletion, depreciation and amortization expense per barrel for the three and six months ended June 30, 2019 from the comparable periods in 2018 was primarily due to the impact of fluctuations in sales volumes from different underlying operations, along with the adoption of IFRS 16. The increase in depletion, depreciation and amortization expense per barrel for the second quarter of 2019 from the first quarter of 2019 was primarily due to the impact of lower production volumes on a relatively fixed cost base. Depletion, depreciation and amortization expense for the six months ended June 30, 2019 reflected an increase of $41 million ($0.56 per bbl) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Expense	**$ 15**	$ 16	$ 15	**$ 31**	$ 30
$/bbl (1)	**$ 0.46**	$ 0.41	$ 0.41	**$ 0.43**	$ 0.39

(1) Amounts expressed on a per unit basis are based on 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 per bbl for the six months ended June 30, 2019 increased 10% to $0.43 per bbl from $0.39 per bbl for the six months ended June 30, 2018. Asset retirement obligation accretion expense of $0.46 per bbl for the second quarter of 2019 increased 12% from $0.41 per bbl for the second quarter of 2018 and the first quarter of 2019. The increase in asset retirement obligation accretion expense for the three and six months ended June 30, 2019 from the comparable periods was primarily due to lower sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Revenue	**$ 20**	$ 21	$ 25	**$ 41**	$ 52
Less:					
Production expense	**5**	6	6	**11**	11
Depreciation	**4**	3	4	**7**	7
Equity loss from investment	**66**	60	2	**126**	3
Segment earnings (loss) before taxes	**$ (55)**	$ (48)	$ 13	**$ (103)**	$ 31

The Company has a 50% interest in the Redwater Partnership. Redwater Partnership has entered into agreements to construct and operate a 50,000 bbl/d bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 bbl/d of bitumen feedstock for the Company and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission (“APMC”), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing SCO into refined products. The Project's bitumen refining operations remain in the commissioning phase. Design modifications to the reactor burners in the gasifier unit and repairs identified to address stress cracking in certain stainless steel piping will continue into the fourth quarter of 2019. Currently, the heavy oil units are expected to commence commercial processing of bitumen in late 2019. As at June 30, 2019, the total facility capital cost ("FCC") budget for the Project, net of margins from pre-commercial sales, totaled approximately $9,800 million.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at June 30, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $182 million, for a Company total of $621 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at June 30, 2019, the Company had recognized $97 million in prepaid cost of service tolls (December 31, 2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis and matures in February 2020. As at June 30, 2019, Redwater Partnership had borrowings of $2,407 million under the syndicated credit facility.

The equity loss from investment of $126 million for the six months ended June 30, 2019 includes the impact of $98 million of interest expense and $42 million of depletion, depreciation and amortization expense recognized following the completion of commissioning and startup activities in the light oil units (six months ended June 30, 2018 – loss of $3 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Expense	**$ 84**	$ 70	$ 76	**$ 154**	$ 157
$/BOE (1)	**$ 0.90**	$ 0.76	$ 0.79	**$ 0.83**	$ 0.81

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense per BOE for the six months ended June 30, 2019 increased 2% to $0.83 per BOE from $0.81 per BOE for the six months ended June 30, 2018. Administration expense for the second quarter of 2019 of $0.90 per BOE increased 14% from $0.79 per BOE for the second quarter of 2018 and increased 18% from $0.76 per BOE for the first quarter of 2019. Administration expense per BOE increased for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily due to lower sales volumes. The increase in administration expense per BOE in the second quarter of 2019 from the first quarter of 2019 was primarily due to lower capital recoveries in the second quarter of 2019. Administration expense for the six months ended June 30, 2019 reflected a decrease of $12 million ($0.06 per BOE) related to the adoption of IFRS 16.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
(Recovery) expense	**$ (7)**	$ 62	$ 175	**$ 55**	$ 87

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded a $55 million share-based compensation expense for the six months ended June 30, 2019, 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. Included within the share-based compensation expense for the six months ended June 30, 2019 was $17 million related to performance share units granted to certain executive employees (June 30, 2018 – $6 million). For the six months ended June 30, 2019, the Company charged $3 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (June 30, 2018 – $9 million).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts and interest rates)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Expense, gross	**$ 214**	$ 211	$ 207	**$ 425**	$ 412
Less: capitalized interest	**17**	20	17	**37**	32
Expense, net	**$ 197**	$ 191	$ 190	**$ 388**	$ 380
$/BOE (1)	**$ 2.12**	$ 2.06	$ 1.99	**$ 2.09**	$ 1.95
Average effective interest rate	**4.1%**	4.1%	3.9%	**4.1%**	3.8%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for the three and six months ended June 30, 2019 increased from the comparable periods in 2018 primarily due to interest expense on lease liabilities recognized due to the adoption of IFRS 16, partially offset by lower average debt levels in 2019. Gross interest and other financing expense for the second quarter of 2019 was comparable with the first quarter of 2019. Capitalized interest of $37 million for the six months ended June 30, 2019 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense per BOE for the six months ended June 30, 2019 increased 7% to $2.09 per BOE from $1.95 per BOE for the six months ended June 30, 2018. Net interest and other financing expense per BOE for the second quarter of 2019 increased 7% to $2.12 per BOE from $1.99 per BOE for the second quarter of 2018 and increased 3% from $2.06 per BOE for the first quarter of 2019. The increase in net interest and other financing expense per BOE for the three and six months ended June 30, 2019 from the comparable periods in 2018 primarily reflected the adoption of IFRS 16. The increase for the second quarter of 2019 from the first quarter of 2019 was primarily due to lower sales volumes in the second quarter of 2019. Net interest and other financing expense for the six months ended June 30, 2019 reflected an increase of $34 million ($0.18 per BOE) related to the adoption of IFRS 16.

The Company’s average effective interest rate for the six months ended June 30, 2019 increased from the six months ended June 30, 2018 primarily due to the impact of higher benchmark interest rates on the Company's outstanding bank credit facilities and US commercial paper program. The Company’s average effective interest rate for the second quarter of 2019 was consistent with the comparable periods.

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 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Crude oil and NGLs financial instruments	**$ 13**	$ 28	$ —	**$ 41**	$ —
Natural gas financial instruments	**(2)**	(1)	(3)	**(3)**	(3)
Foreign currency contracts	**16**	—	(24)	**16**	(43)
Realized loss (gain)	**27**	27	(27)	**54**	(46)
Crude oil and NGLs financial instruments	**(15)**	5	—	**(10)**	—
Natural gas financial instruments	**1**	—	16	**1**	16
Foreign currency contracts	**(2)**	9	(24)	**7**	(57)
Unrealized (gain) loss	**(16)**	14	(8)	**(2)**	(41)
Net loss (gain)	**$ 11**	$ 41	$ (35)	**$ 52**	$ (87)

During the six months ended June 30, 2019, net realized risk management losses were related to the settlement of crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized gain of $2 million ($nil after-tax) on its risk management activities for the six months ended June 30, 2019, including an unrealized gain of $16 million ($13 million after-tax) for the second quarter of 2019 (March 31, 2019 – unrealized loss of $14 million, $13 million after-tax; June 30, 2018 – unrealized gain of $8 million, $11 million after-tax).

Further details related to outstanding derivative financial instruments at June 30, 2019 are disclosed in note 15 to the Company’s unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Net realized loss (gain)	**$ 2**	$ (6)	$ (7)	**$ (4)**	$ 109
Net unrealized (gain) loss	**(219)**	(233)	178	**(452)**	340
Net (gain) loss [1]	**$ (217)**	$ (239)	$ 171	**$ (456)**	$ 449

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

The net realized foreign exchange gain for the six months ended June 30, 2019 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, 2019 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended June 30, 2019 – unrealized loss of $28 million, March 31, 2019 – unrealized loss of $30 million, June 30, 2018 – unrealized gain of $25 million; six months ended June 30, 2019 – unrealized loss of $58 million, June 30, 2018 – unrealized gain of $65 million). The US/Canadian dollar exchange rate at June 30, 2019 was US$0.7639 (March 31, 2019 – US$0.7485, June 30, 2018 – US$0.7609).

INCOME TAXES

	Three Months Ended			Six Months Ended	
($ millions, except income tax rates)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
North America [1]	**$ 78**	$ 163	$ 247	**$ 241**	$ 397
North Sea	**28**	29	7	**57**	8
Offshore Africa	**11**	12	16	**23**	21
PRT [2] – North Sea	**(43)**	(42)	(16)	**(85)**	(20)
Other taxes	**3**	3	3	**6**	5
Current income tax expense	**77**	165	257	**242**	411
Deferred corporate income tax (recovery) expense	**(1,359)**	94	156	**(1,265)**	283
Deferred PRT [2] – North Sea	**1**	—	7	**1**	17
Deferred income tax (recovery) expense	**(1,358)**	94	163	**(1,264)**	300
	(1,281)	259	420	**(1,022)**	711
Income tax rate and other legislative changes	**1,618**	—	—	**1,618**	—
	$ 337	$ 259	$ 420	**$ 596**	$ 711
Effective income tax rate on adjusted net earnings from operations [3]	**26%**	26%	23%	**26%**	23%

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

(2) Petroleum Revenue Tax

(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The effective income tax rate for the three and six months ended June 30, 2019 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 PRT recovery in the North Sea for the three and six months ended June 30, 2019 and the comparable periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with further 1% rate reductions every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

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.

For 2019, current income tax expense is now targeted to range from $450 million to $650 million in Canada and $35 million to $60 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2019	Mar 31 2019	Jun 30 2018	Six Months Ended Jun 30 2019	Jun 30 2018
Exploration and Evaluation					
Net property acquisitions [2]	**$ 91**	$ 1	$ —	**$ 92**	$ (2)
Net expenditures	**37**	32	8	**69**	66
Total Exploration and Evaluation	**128**	33	8	**161**	64
Property, Plant and Equipment					
Net property acquisitions [2]	**3,134**	24	(70)	**3,158**	92
Well drilling, completion and equipping	**171**	254	350	**425**	671
Production and related facilities	**271**	287	308	**558**	572
Capitalized interest and other [3]	**23**	29	25	**52**	48
Total Property, Plant and Equipment	**3,599**	594	613	**4,193**	1,383
Total Exploration and Production	**3,727**	627	621	**4,354**	1,447
Oil Sands Mining and Upgrading					
Project costs [4]	**106**	76	63	**182**	129
Sustaining capital	**210**	140	152	**350**	257
Turnaround costs	**17**	8	46	**25**	59
Capitalized interest and other [4]	**9**	10	30	**19**	25
Total Oil Sands Mining and Upgrading	**342**	234	291	**576**	470
Midstream and Refining	**3**	2	5	**5**	9
Abandonments [5]	**41**	108	50	**149**	140
Head office	**12**	6	7	**18**	11
Total net capital expenditures	**$ 4,125**	$ 977	$ 974	**$ 5,102**	$ 2,077
By segment					
North America [2]	**$ 3,612**	$ 524	$ 568	**$ 4,136**	$ 1,340
North Sea	**42**	36	3	**78**	38
Offshore Africa	**73**	67	50	**140**	69
Oil Sands Mining and Upgrading	**342**	234	291	**576**	470
Midstream and Refining	**3**	2	5	**5**	9
Abandonments [5]	**41**	108	50	**149**	140
Head office	**12**	6	7	**18**	11
Total	**$ 4,125**	$ 977	$ 974	**$ 5,102**	$ 2,077

(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) Includes cash consideration paid of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in the second quarter of 2019.

(3) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.

(4) Includes Horizon Phase 2/3 construction costs.

(5) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Cash flows used in investing activities	***$ 4,464***	*$ 1,029*	*$ 1,138*	***$ 5,493***	*$ 2,507*
Net change in non-cash working capital (1)	***(380)***	*(160)*	*(207)*	***(540)***	*(542)*
Investment in other long-term assets	**—**	—	*(7)*	**—**	*(28)*
Abandonment expenditures (2)	***41***	*108*	*50*	***149***	*140*
Net capital expenditures	***$ 4,125***	*$ 977*	*$ 974*	***$ 5,102***	*$ 2,077*

(1) Includes net working capital and other long-term assets of $195 million related to the acquisition of assets from Devon in the second quarter of 2019.

(2) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial Highlights" 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 costs.

Net capital expenditures for the six months ended June 30, 2019 were $5,102 million compared with $2,077 million for the six months ended June 30, 2018. Net capital expenditures for the second quarter of 2019 were $4,125 million, compared with $974 million for the second quarter of 2018 and $977 million for the first quarter of 2019.

Net capital expenditures for the three and six months ended June 30, 2019 included $3,217 million of cash consideration paid to acquire assets from Devon, reflecting the Company's capital flexibility and ability to execute on opportunistic acquisitions. The Company also paid $195 million to acquire working capital and other long-term assets from Devon.

Drilling Activity (1)

	Three Months Ended			Six Months Ended	
(number of net wells)	**Jun 30 2019**	Mar 31 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Net successful natural gas wells	**2**	8	4	**10**	9
Net successful crude oil wells (2)	**8**	30	81	**38**	203
Dry wells	**2**	1	—	**3**	2
Stratigraphic test / service wells	**3**	332	27	**335**	477
Total	**15**	371	112	**386**	691
Success rate (excluding stratigraphic test / service wells)	**83%**	97%	100%	**94%**	99%

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

(2) Includes bitumen wells.

North America

During the second quarter of 2019, the Company targeted 2 net natural gas wells, 5 net primary heavy crude oil wells and 4 net light crude oil wells.

North Sea

During the second quarter of 2019, the Company completed one gross light crude oil well (0.9 on a net basis) in the North Sea.

Offshore Africa

During the second quarter of 2019, the Company completed one gross appraisal well (0.6 on a net basis) at Kossipo and one gross injection well (0.6 on a net basis) at Baobab.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Jun 30 2019	Mar 31 2019	Dec 31 2018	Jun 30 2018
Working capital (1)	**$ 709**	$ 319	$ (601)	$ 942
Long-term debt (2) (3)	**$ 23,507**	$ 20,990	$ 20,623	$ 21,397
Less: cash and cash equivalents	**398**	90	101	182
Long-term debt, net	**$ 23,109**	$ 20,900	$ 20,522	$ 21,215
Share capital	**$ 9,320**	$ 9,358	$ 9,323	$ 9,405
Retained earnings	**24,927**	22,852	22,529	22,994
Accumulated other comprehensive income	**27**	58	122	12
Shareholders' equity	**$ 34,274**	$ 32,268	$ 31,974	$ 32,411
Debt to book capitalization (3) (4)	**40.3%**	39.3%	39.1%	39.6%
Debt to market capitalization (3) (5)	**35.4%**	32.2%	34.1%	26.7%
After-tax return on average common shareholders' equity (6)	**14.7%**	9.2%	8.0%	8.3%
After-tax return on average capital employed (3) (7)	**9.9%**	6.6%	5.9%	5.9%

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

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

(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.

(4) Calculated as net current and long-term debt; divided by the book value of common shareholders' equity plus net current and long-term debt.

(5) Calculated as net current and long-term debt; divided by the market value of common shareholders' equity plus net current and long-term debt.

(6) Calculated as net earnings (loss) for the twelve month trailing period; as a percentage of average common shareholders' equity for the twelve month trailing period.

(7) Calculated as net earnings (loss) plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed for the twelve month trailing period.

As at June 30, 2019, 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 "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2018. 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 the conditions of the market. The Company continues to believe that its internally generated cash flows from operating activities supported by the implementation of 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;
- 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;
- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
  - Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at June 30, 2019, the non-revolving term credit facilities were fully drawn.

- During the second quarter of 2019, the Company extended $330 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $2,095 million outstanding under this facility continues under the previous terms and matures in June 2021.The other $2,425 million revolving credit facility matures in June 2022. Each of the $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
- During the second quarter of 2019, the Company repaid $500 million of 3.05% medium-term notes.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- Subsequent to June 30, 2019, 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, expiring in August 2021, and replacing the Company's previous base shelf prospectuses, which would have expired in August 2019. 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.

- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- 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.

As at June 30, 2019, the Company had in place revolving bank credit facilities of $4,975 million, of which $4,163 million was available. Additionally, the Company had in place fully drawn term credit facilities of $8,000 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at June 30, 2019, the Company had total US dollar denominated debt with a carrying amount of $14,512 million (US$11,087 million), before transaction costs and original issue discounts. This included $5,872 million (US$4,487 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,437 million). The fixed repayment amount of these hedging instruments is $5,697 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $175 million to $14,337 million as at June 30, 2019.

Net long-term debt was $23,109 million at June 30, 2019, resulting in a debt to book capitalization ratio of 40.3% (December 31, 2018 – 39.1%); this ratio is within 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 is 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 at June 30, 2019 are discussed in note 8 of the Company's unaudited interim consolidated 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, 2019, 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, 2019, 8,000 bbl/d of currently forecasted crude oil volumes were hedged using WCS differential swaps for July to September 2019, as well as 115,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps for July to October 2019. Further details related to the Company's commodity derivative financial instruments outstanding at June 30, 2019 are discussed in note 15 of the Company's unaudited interim consolidated financial statements.

The maturity dates of 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)	$	3,970	$	4,046	$	8,100	$	7,511
Other long-term liabilities (2)	$	314	$	209	$	431	$	1,069
Interest and other financing expense (3)	$	977	$	840	$	1,830	$	5,126

(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, $236 million; one to less than two years, $184 million; two to less than five years, $386 million; and thereafter, $1,069 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, 2019.

Share Capital

As at June 30, 2019, there were 1,188,319,000 common shares outstanding (December 31, 2018 – 1,201,886,000 common shares) and 51,644,000 stock options outstanding. As at July 30, 2019, the Company had 1,186,191,000 common shares outstanding and 51,265,000 stock options outstanding.

On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable on April 1, 2019 (previous quarterly dividend rate of $0.355 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's NCIB approved in May 2018 expired on May 22, 2019.

For the six months ended June 30, 2019, the Company purchased for cancellation 17,100,000 common shares at a weighted average price of $36.95 per common share for a total cost of $632 million. Retained earnings were reduced by $498 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2019, the Company purchased 2,300,000 common shares at a weighted average price of $34.55 per common share for a total cost of $79 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at June 30, 2019 (1):

($ millions)		Remaining 2019		2020		2021		2022		2023		Thereafter
Product transportation (2)	$	357	$	719	$	691	$	614	$	495	$	4,663
North West Redwater Partnership service toll (3)	$	36	$	126	$	157	$	158	$	157	$	2,858
Offshore vessels and equipment	$	57	$	89	$	64	$	9	$	—	$	—
Field equipment and power	$	22	$	20	$	21	$	20	$	21	$	274
Other	$	18	$	28	$	21	$	18	$	17	$	48

(1) Subsequent to adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in the 'Liquidity and Capital Resources' section of this MD&A.

(2) The Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon in the second quarter of 2019.

(3) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service toll is $1,251 million of interest payable over the 30 year tolling period.

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.

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, including the adoption of IFRS 16 "Leases", refer to the audited consolidated financial statements for the year ended December 31, 2018 and the unaudited interim consolidated financial statements for the three and six months ended June 30, 2019.

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 “Leases”, which provides guidance on accounting for leases. The new standard replaced IAS 17 “Leases” and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 were treated as short-term leases;
- exclusion of indirect costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

The Company did not apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of $1,539 million, measured at the present value of the remaining lease payments, discounted at the Company’s incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. The adoption of IFRS 16 resulted in increases in depletion, depreciation and amortization expense and interest expense and corresponding decreases in production, transportation and administration expenses. Under the new standard, the Company reports cash outflows for payment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

For further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at June 30, 2019 refer to the audited consolidated financial statements for the year ended December 31, 2018 and the unaudited interim financial statements for the three and six months ended June 30, 2019.

The impacts of the adoption of IFRS 16 are discussed within the respective sections of this MD&A. The most significant impacts of the adoption of the new Leases standard are as follows:

- Cash flow from operating activities and adjusted funds flow increased as the principal portion of lease payments, previously classified as cash flows from operating activities is now reported as an investing activity;
- Increased depletion, depreciation and amortization expense and interest expense;
- Decreased production expense, transportation expense and administration expense; and
- Commitments for leases, previously reported in the "Commitments and Contingencies" section of this MD&A, are now reported in the maturity table in the "Liquidity and Capital Resources" section of this MD&A.

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 annual MD&A and the audited consolidated financial statements for the year ended December 31, 2018.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the six months ended June 30, 2019 that have materially affected, or are reasonably likely to materially affect the Company's ICFR. Based on 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.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Jun 30 2019	Dec 31 2018
ASSETS			
Current assets			
Cash and cash equivalents		**$ 398**	$ 101
Accounts receivable		**2,124**	1,148
Inventory		**1,189**	955
Prepaids and other		**315**	176
Investments	6	**547**	524
Current portion of other long-term assets	7	**72**	116
		4,645	3,020
Exploration and evaluation assets	3	**2,648**	2,637
Property, plant and equipment	4	**68,464**	64,559
Lease assets	5	**1,865**	—
Other long-term assets	7	**1,333**	1,343
		$ 78,955	$ 71,559
LIABILITIES			
Current liabilities			
Accounts payable		**$ 924**	$ 779
Accrued liabilities		**2,360**	2,356
Current income taxes payable		**64**	151
Current portion of long-term debt	8	**3,964**	1,141
Current portion of other long-term liabilities	5,9	**588**	335
		7,900	4,762
Long-term debt	8	**19,543**	19,482
Other long-term liabilities	5,9	**7,069**	3,890
Deferred income taxes		**10,169**	11,451
		44,681	39,585
SHAREHOLDERS' EQUITY			
Share capital	11	**9,320**	9,323
Retained earnings		**24,927**	22,529
Accumulated other comprehensive income	12	**27**	122
		34,274	31,974
		$ 78,955	$ 71,559

Commitments and contingencies (note 16).

Approved by the Board of Directors on July 31, 2019.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Jun 30 2019	Three Months Ended Jun 30 2018	Six Months Ended Jun 30 2019	Six Months Ended Jun 30 2018
Product sales	17	**$ 5,931**	$ 6,389	**$ 11,472**	$ 12,124
Less: royalties		**(369)**	(437)	**(662)**	(698)
Revenue		**5,562**	5,952	**10,810**	11,426
Expenses					
Production		**1,533**	1,622	**3,063**	3,252
Transportation, blending and feedstock		**996**	1,142	**2,035**	2,294
Depletion, depreciation and amortization	4,5	**1,307**	1,270	**2,570**	2,527
Administration		**84**	76	**154**	157
Share-based compensation	9	**(7)**	175	**55**	87
Asset retirement obligation accretion	9	**46**	47	**90**	93
Interest and other financing expense		**197**	190	**388**	380
Risk management activities	15	**11**	(35)	**52**	(87)
Foreign exchange (gain) loss		**(217)**	171	**(456)**	449
Gain on acquisition and revaluation of properties		**—**	(139)	**—**	(139)
Loss from investments	6,7	**62**	31	**89**	137
		4,012	4,550	**8,040**	9,150
Earnings before taxes		**1,550**	1,402	**2,770**	2,276
Current income tax expense	10	**77**	257	**242**	411
Deferred income tax (recovery) expense	10	**(1,358)**	163	**(1,264)**	300
Net earnings		**$ 2,831**	$ 982	**$ 3,792**	$ 1,565
Net earnings per common share					
Basic	14	**$ 2.37**	$ 0.80	**$ 3.17**	$ 1.28
Diluted	14	**$ 2.36**	$ 0.80	**$ 3.16**	$ 1.27

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2019	Three Months Ended Jun 30 2018	Six Months Ended Jun 30 2019	Six Months Ended Jun 30 2018
Net earnings	**$ 2,831**	$ 982	**$ 3,792**	$ 1,565
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $1 million (2018 – $nil) – three months ended; $6 million (2018 – $2 million) – six months ended	**20**	1	**49**	(15)
Reclassification to net earnings, net of taxes of $2 million (2018 – $1 million) – three months ended; $3 million (2018 – $3 million) – six months ended	**10**	(12)	**(23)**	(22)
	30	(11)	**26**	(37)
Foreign currency translation adjustment				
Translation of net investment	**(61)**	46	**(121)**	117
Other comprehensive income (loss), net of taxes	**(31)**	35	**(95)**	80
Comprehensive income	**$ 2,800**	$ 1,017	**$ 3,697**	$ 1,645

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended Jun 30 2019	Six Months Ended Jun 30 2018
Share capital	11		
Balance – beginning of period		**$ 9,323**	$ 9,109
Issued upon exercise of stock options		**118**	273
Previously recognized liability on stock options exercised for common shares		**13**	101
Purchase of common shares under Normal Course Issuer Bid		**(134)**	(78)
Balance – end of period		**9,320**	9,405
Retained earnings			
Balance – beginning of period		**22,529**	22,612
Net earnings		**3,792**	1,565
Purchase of common shares under Normal Course Issuer Bid	11	**(498)**	(363)
Dividends on common shares	11	**(896)**	(820)
Balance – end of period		**24,927**	22,994
Accumulated other comprehensive income	12		
Balance – beginning of period		**122**	(68)
Other comprehensive income (loss), net of taxes		**(95)**	80
Balance – end of period		**27**	12
Shareholders' equity		**$ 34,274**	$ 32,411

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Jun 30 2019**	Three Months Ended Jun 30 2018	Six Months Ended **Jun 30 2019**	Six Months Ended Jun 30 2018
Operating activities					
Net earnings		**$ 2,831**	$ 982	**$ 3,792**	$ 1,565
Non-cash items					
Depletion, depreciation and amortization		**1,307**	1,270	**2,570**	2,527
Share-based compensation		**(7)**	175	**55**	87
Asset retirement obligation accretion		**46**	47	**90**	93
Unrealized risk management gain		**(16)**	(8)	**(2)**	(41)
Unrealized foreign exchange (gain) loss		**(219)**	178	**(452)**	340
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**—**	146
Gain on acquisition and revaluation of properties		**—**	(139)	**—**	(139)
Loss from investments	6,7	**68**	38	**103**	151
Deferred income tax (recovery) expense		**(1,358)**	163	**(1,264)**	300
Other		**20**	14	**(100)**	15
Abandonment expenditures		**(41)**	(50)	**(149)**	(140)
Net change in non-cash working capital		**230**	(57)	**(786)**	178
Cash flows from operating activities		**2,861**	2,613	**3,857**	5,082
Financing activities					
Issue (repayment) of bank credit facilities and commercial paper, net	8	**3,273**	(760)	**3,908**	(379)
Repayment of medium-term notes	8	**(500)**	—	**(500)**	—
Repayment of US dollar debt securities		**—**	—	**—**	(1,236)
Payment of lease liabilities	5	**(57)**	—	**(109)**	—
Issue of common shares on exercise of stock options		**35**	167	**118**	273
Purchase of common shares under Normal Course Issuer Bid		**(391)**	(441)	**(632)**	(441)
Dividends on common shares		**(449)**	(411)	**(852)**	(747)
Cash flows from (used in) financing activities		**1,911**	(1,445)	**1,933**	(2,530)
Investing activities					
Net expenditures on exploration and evaluation assets		**(37)**	(8)	**(70)**	(64)
Net expenditures on property, plant and equipment		**(830)**	(916)	**(1,666)**	(1,873)
Acquisition of Devon assets	4	**(3,412)**	—	**(3,412)**	—
Investment in other long-term assets		**—**	(7)	**—**	(28)
Net change in non-cash working capital		**(185)**	(207)	**(345)**	(542)
Cash flows used in investing activities		**(4,464)**	(1,138)	**(5,493)**	(2,507)
Increase in cash and cash equivalents		**308**	30	**297**	45
Cash and cash equivalents – beginning of period		**90**	152	**101**	137
Cash and cash equivalents – end of period		**$ 398**	$ 182	**$ 398**	$ 182
Interest paid, net		**$ 183**	$ 223	**$ 411**	$ 483
Income taxes paid (received)		**$ 60**	$ (14)	**$ 286**	$ (77)

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 (“UK”) 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 ("Redwater Partnership"), 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, 2018, 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 that are 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, 2018.

2. CHANGES IN ACCOUNTING POLICIES

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 “Leases”, which provides guidance on accounting for leases. The new standard replaced IAS 17 “Leases” and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 were treated as short-term leases;
- exclusion of indirect costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

The Company did not apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of $1,539 million, measured at the present value of the remaining lease payments, discounted at the Company's incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. The adoption of IFRS 16 resulted in increases in depletion, depreciation and amortization expense and interest expense and corresponding decreases in production, transportation and administration expenses. Under the new standard, the

Company reports cash outflows for payment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at June 30, 2019 are shown in note 5.

Effective January 1, 2019, the Company's accounting policy for Leases is as follows:

At inception of a contract, the Company assesses whether a contract is, or contains a lease. A contract is, or contains a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether: the contract involves the use of an identified asset; the Company has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use; and, the Company has the right to direct the use of the asset.

The Company recognizes a lease asset and a lease liability at the commencement date of the lease contract, which is the date that the lease asset is available to the Company. The lease asset is initially measured at cost. The cost of a lease asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the lease asset is depreciated using the straight-line method over the earlier of the end of the useful life of the lease asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Company's incremental borrowing rate. Lease payments include fixed lease payments, variable lease payments based on indices or rates, residual value guarantees, and purchase options expected to be exercised. Subsequent to initial recognition, the lease liability is measured at amortized cost using the effective interest method. Lease liabilities are remeasured if there are changes in the lease term or if the Company changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also remeasured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees.

Lease assets are reported in a separate caption in the consolidated balance sheet. Lease liabilities are reported within other long-term liabilities in the consolidated balance sheet.

Depreciation on lease assets used in the construction of property, plant and equipment is capitalized to the cost of those assets over their period of use until such time as the property, plant and equipment is substantially available for its intended use.

Where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries are recognized as other income in the consolidated statements of earnings.

Effective January 1, 2019 on adoption of IFRS 16, the Company has applied the following significant accounting estimates and judgments in respect of lease accounting:

Purchase, extension and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgment to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

Changes in other accounting policies

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term assets that form part of the net investment in the associate or the joint venture. The Company retrospectively adopted the amendments on January 1, 2019. These amendments did not have a significant impact on the Company's consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The Company adopted the interpretation on January 1, 2019. The interpretation did not have a significant impact on the Company's 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, 2018	$ 2,348	$ —	$ 37	$ 252	$ 2,637
Additions	**35**	**—**	**35**	**—**	**70**
Acquisition of Devon assets (note 4)	**91**	**—**	**—**	**—**	**91**
Transfers to property, plant and equipment	**(149)**	**—**	**—**	**—**	**(149)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At June 30, 2019	**$ 2,325**	**$ —**	**$ 71**	**$ 252**	**$ 2,648**

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, 2018	$ 67,007	$ 7,321	$ 5,471	$ 43,147	$ 441	$ 435	$ 123,822
Additions	**1,806**	**183**	**130**	**889**	**5**	**18**	**3,031**
Acquisition of Devon assets	**3,325**	**—**	**—**	**—**	**—**	**—**	**3,325**
Transfers from E&E assets	**149**	**—**	**—**	**—**	**—**	**—**	**149**
Disposals/derecognitions and other	**(245)**	**—**	**(1,515)**	**(144)**	**—**	**(3)**	**(1,907)**
Foreign exchange adjustments and other	**—**	**(302)**	**(218)**	**—**	**—**	**—**	**(520)**
At June 30, 2019	**$ 72,042**	**$ 7,202**	**$ 3,868**	**$ 43,892**	**$ 446**	**$ 450**	**$ 127,900**
Accumulated depletion and depreciation							
At December 31, 2018	$ 43,881	$ 5,735	$ 4,203	$ 4,981	$ 138	$ 325	$ 59,263
Expense	**1,480**	**102**	**101**	**750**	**7**	**12**	**2,452**
Disposals/derecognitions	**(245)**	**—**	**(1,515)**	**(144)**	**—**	**(3)**	**(1,907)**
Foreign exchange adjustments and other	**(8)**	**(213)**	**(151)**	**—**	**—**	**—**	**(372)**
At June 30, 2019	**$ 45,108**	**$ 5,624**	**$ 2,638**	**$ 5,587**	**$ 145**	**$ 334**	**$ 59,436**
Net book value							
- at June 30, 2019	**$ 26,934**	**$ 1,578**	**$ 1,230**	**$ 38,305**	**$ 301**	**$ 116**	**$ 68,464**
- at December 31, 2018	$ 23,126	$ 1,586	$ 1,268	$ 38,166	$ 303	$ 110	$ 64,559

Project costs not subject to depletion and depreciation	**Jun 30 2019**	Dec 31 2018
Thermal Oil Sands	**$ 1,727**	$ 1,424

During the six months ended June 30, 2019, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment, excluding the impact of the acquisition disclosed below, for net cash consideration of $32 million and assumed associated asset retirement obligations of $20 million. No net deferred income tax liabilities or pre-tax gains were recognized on these net transactions.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the six months ended June 30, 2019, pre-tax interest of $37 million (June 30, 2018 – $32 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 4.1% (June 30, 2018 – 3.8%).

Acquisition of Thermal In Situ and Primary Heavy Crude Oil Assets

On June 27, 2019, the Company completed the acquisition of substantially all of the assets of Devon Canada Corporation ("Devon") including thermal in situ and heavy crude oil assets, for total cash purchase consideration of $3,412 million, subject to final closing adjustments.

In connection with the acquisition, the Company arranged a new $3,250 million committed term facility (note 8) and assumed certain product transportation commitments (note 16).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. Key assumptions used in the determination of estimated fair value were future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, discount rates, and income taxes.

The following provides a summary of the net assets acquired and (liabilities) assumed relating to the acquisition:

Property, plant and equipment	$	**3,325**
Exploration and evaluation assets		**91**
Inventory, prepaids and other long-term assets		**195**
Accrued liabilities		**(21)**
Asset retirement obligations		**(178)**
Net assets acquired	$	**3,412**

The above amounts are estimates, and may be subject to change based on the receipt of new information.

The impact of the acquisition from closing on June 27, 2019 to June 30, 2019, was not significant to the Company's revenue or operating results for the three and six months ended June 30, 2019. If the acquisition had been completed on January 1, 2019, the Company estimates that pro forma revenue would have increased by approximately $1,010 million to $11,820 million and pro forma revenue, less production and transportation, blending and feedstock expenses would have increased by approximately $670 million to $6,382 million for the six months ended June 30, 2019. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2019, or of future results. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At January 1, 2019 [(1)]	$ 823	$ 332	$ 252	$ 132	$ 1,539
Additions	**444**	**14**	**—**	**3**	**461**
Depreciation	**(49)**	**(24)**	**(32)**	**(13)**	**(118)**
Derecognitions	**—**	**(3)**	**—**	**—**	**(3)**
Foreign exchange adjustments and other	**(1)**	**(1)**	**(11)**	**(1)**	**(14)**
At June 30, 2019	**$ 1,217**	**$ 318**	**$ 209**	**$ 121**	**$ 1,865**

(1) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach. At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

Lease assets, by Segment

	Jun 30 2019
Exploration and Production	
North America	**$ 327**
North Sea	**48**
Offshore Africa	**169**
Oil Sands Mining and Upgrading	**1,217**
Head office	**104**
	$ 1,865

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at June 30, 2019 were as follows:

	Jun 30 2019
Lease liabilities	**$ 1,875**
Less: current portion	**236**
	$ 1,639

In addition to the lease assets disclosed above, on an ongoing basis the Company enters into short-term leases related to its Exploration and Production and Oil Sands Mining and Upgrading activities.

Other amounts included in net earnings for the period are provided below:

	Three Months Ended Jun 30 2019	Six Months Ended Jun 30 2019
Expenses relating to short-term leases [(1)]	**$ 102**	**$ 226**
Interest expense on lease liabilities	**$ 19**	**$ 34**
Variable lease payments not included in the measurement of lease liabilities	**$ 28**	**$ 52**

(1) In addition, during the three months ended June 30, 2019, the Company capitalized $78 million (six months ended June 30, 2019 - $159 million) of short-term leases as additions to property, plant and equipment.

	Three Months Ended		Six Months Ended	
	Jun 30 2019		**Jun 30 2019**	
Total cash outflows for leases during the period [1]	$	284	$	580

(1) Comprised of cash outflows relating to lease liabilities, short-term leases, and variable lease payments.

Impacts to the consolidated financial statements on transition

On transition to IFRS 16, the Company recognized $1,539 million of lease liabilities and corresponding lease assets. Lease liabilities were measured at the discounted value of lease payments using a weighted average incremental borrowing rate of 4.0% at January 1, 2019.

A reconciliation showing the impact of adoption of the standard is provided below:

		Jan 1 2019
Leases previously reported as commitments at December 31, 2018 [1] [2]	$	**1,430**
Impact of discounting		**(317)**
Leases previously reported as commitments, discounted at January 1, 2019		**1,113**
Leases recognized at adoption on January 1, 2019:		
Lease extension options and renewals reasonably certain to be exercised		**243**
Arrangements determined to be leases under IFRS 16		**83**
Leases entered into on behalf of a joint operation [3]		**100**
Lease liabilities recognized at January 1, 2019	$	**1,539**

(1) At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

(2) Commitments for operating leases, previously reported in note 16, are now reported as part of lease liabilities and included in other long-term liabilities in note 9. Operating leases previously reported in note 16 have been aggregated into one line in the reconciliation table. Other non-lease commitments continue to be reported in the table in note 16.

(3) In accordance with the previous accounting for operating leases used in joint operations, the Company reported commitments and related expenses in accordance with the Company's proportionate interest in the joint operation. Under IFRS 16, where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability.

6. INVESTMENTS

As at June 30, 2019, the Company had the following investments:

	Jun 30 2019	Dec 31 2018
Investment in PrairieSky Royalty Ltd.	**$ 416**	$ 400
Investment in Inter Pipeline Ltd.	**131**	124
	$ 547	$ 524

Investment in PrairieSky Royalty Ltd.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") 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, 2019, the Company's investment in PrairieSky was classified as a current asset.

The (gain) loss from the investment in PrairieSky was comprised as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Fair value (gain) loss from PrairieSky	**$ (9)**	$ 51	**$ (16)**	$ 139
Dividend income from PrairieSky	**(4)**	(4)	**(9)**	(8)
	$ (13)	$ 47	**$ (25)**	$ 131

Investment in Inter Pipeline Ltd.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") 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, 2019, the Company's investment in Inter Pipeline was classified as a current asset.

The loss (gain) from the investment in Inter Pipeline was comprised as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2019	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Fair value loss (gain) from Inter Pipeline	**$ 11**	$ (15)	**$ (7)**	$ 9
Dividend income from Inter Pipeline	**(2)**	(3)	**(5)**	(6)
	$ 9	$ (18)	**$ (12)**	$ 3

7. OTHER LONG-TERM ASSETS

		Jun 30 2019		Dec 31 2018
Investment in North West Redwater Partnership	$	161	$	287
North West Redwater Partnership subordinated debt [(1)]		621		591
Risk management (note 15)		267		373
Prepaid cost of service toll		97		62
Other		259		146
		1,405		1,459
Less: current portion		72		116
	$	1,333	$	1,343

(1) Includes accrued interest.

Investment in North West Redwater Partnership

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership’s voting and decision-making structure and legal form. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission (“APMC”), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products.The Project's bitumen refining operations remain in the commissioning phase. Design modifications to the reactor burners in the gasifier unit and repairs identified to address stress cracking in certain stainless steel piping will continue into the fourth quarter of 2019. Currently, the heavy oil units are expected to commence commercial processing of bitumen in late 2019. As at June 30, 2019, the total Facility Capital Cost budget for the Project, net of margins from pre-commercial sales, was approximately $9,800 million.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To June 30, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $182 million, for a Company total of $621 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 16). The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at June 30, 2019, the Company had recognized $97 million in prepaid cost of service tolls (December 31, 2018 - $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis and matures in February 2020. As at June 30, 2019, Redwater Partnership had borrowings of $2,407 million under the credit facility.

During the three months ended June 30, 2019, the Company recognized an equity loss from Redwater Partnership of $66 million (three months ended June 30, 2018 – loss of $2 million; six months ended June 30, 2019 - loss of $126 million; six months ended June 30, 2018 - loss of $3 million). The equity loss for the six months ended June 30, 2019 includes the impact of $98 million of interest expense and $42 million of depletion, depreciation and amortization expense recognized following the completion of commissioning and startup activities in the light oil units.

8. LONG-TERM DEBT

	Jun 30 2019	Dec 31 2018
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 4,315**	$ 831
Medium-term notes	**4,800**	5,300
	9,115	6,131
US dollar denominated debt, unsecured		
Bank credit facilities (June 30, 2019 - US$2,937 million; December 31, 2018 - US$2,954 million)	**3,843**	4,031
Commercial paper (June 30, 2019 - US$500 million; December 31, 2018 - US$104 million)	**654**	141
US dollar debt securities (June 30, 2019 - US$7,650 million; December 31, 2018 - US$7,650 million)	**10,015**	10,439
	14,512	14,611
Long-term debt before transaction costs and original issue discounts, net	**23,627**	20,742
Less: original issue discounts, net (1)	**17**	17
transaction costs (1) (2)	**103**	102
	23,507	20,623
Less: current portion of commercial paper	**654**	141
current portion of other long-term debt (1) (2)	**3,310**	1,000
	$ 19,543	$ 19,482

(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, 2019, the Company had in place revolving bank credit facilities of $4,975 million of which $4,163 million was available. Additionally, the Company had in place fully drawn term credit facilities of $8,000 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $1,800 million non-revolving term credit facility maturing May 2020;
- a $2,200 million non-revolving term credit facility maturing October 2020;
- a $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,250 million non-revolving term credit facility maturing June 2022; and
- a £15 million demand credit facility related to the Company’s North Sea operations.

During the second quarter of 2019, the Company extended $330 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The revolving credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime rate.

During the second quarter of 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon (note 4). The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.

Borrowings under the non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, or LIBOR, US base rate or Canadian prime rate. As at June 30, 2019, the non-revolving facilities were fully drawn.

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

The Company’s weighted average interest rate on bank credit facilities and commercial paper outstanding as at June 30, 2019 was 2.6% (June 30, 2018 – 2.4%), and on total long-term debt outstanding for the six months ended June 30, 2019 was 4.1% (June 30, 2018 – 3.8%).

As at June 30, 2019, letters of credit and guarantees aggregating to $424 million were outstanding.

Medium-Term Notes

During the second quarter of 2019, the Company repaid $500 million of 3.05% medium-term notes.

In July 2017, 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. Subsequent to June 30, 2019, 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 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. 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

In July 2017, 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. Subsequent to June 30, 2019, 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 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. 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 2019	Dec 31 2018
Asset retirement obligations	**$ 5,335**	$ 3,886
Share-based compensation	**168**	124
Lease liabilities (note 5)	**1,875**	—
Risk management (note 15)	**53**	17
Deferred purchase consideration (1)	**95**	118
Other	**131**	80
	7,657	4,225
Less: current portion	**588**	335
	$ 7,069	$ 3,890

(1) Relates to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next four years.

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.0% (December 31, 2018 – 5.0%) and inflation rates of up to 2% (December 31, 2018 - up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Jun 30 2019	Dec 31 2018
Balance – beginning of period	$ 3,886	$ 4,327
Liabilities incurred	2	19
Liabilities acquired, net	198	6
Liabilities settled	(149)	(290)
Asset retirement obligation accretion	90	186
Revision of cost, inflation rates and timing estimates	146	(111)
Change in discount rates	1,199	(334)
Foreign exchange adjustments	(37)	83
Balance – end of period	5,335	3,886
Less: current portion	126	186
	$ 5,209	$ 3,700

Share-Based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. 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 are surrendered.

	Jun 30 2019	Dec 31 2018
Balance – beginning of period	$ 124	$ 414
Share-based compensation expense (recovery)	55	(146)
Cash payment for stock options surrendered	(1)	(5)
Transferred to common shares	(13)	(120)
Charged to (recovered from) Oil Sands Mining and Upgrading, net	3	(19)
Balance – end of period	168	124
Less: current portion	130	92
	$ 38	$ 32

Included within share-based compensation liability as at June 30, 2019 was $30 million related to performance share units granted to certain executive employees (December 31, 2018 - $13 million).

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
Expense (recovery)	**Jun 30 2019**	Jun 30 2018	**Jun 30 2019**	Jun 30 2018
Current corporate income tax – North America	**$ 78**	$ 247	**$ 241**	$ 397
Current corporate income tax – North Sea	**28**	7	**57**	8
Current corporate income tax – Offshore Africa	**11**	16	**23**	21
Current PRT [(1)] – North Sea	**(43)**	(16)	**(85)**	(20)
Other taxes	**3**	3	**6**	5
Current income tax	**77**	257	**242**	411
Deferred corporate income tax	**(1,359)**	156	**(1,265)**	283
Deferred PRT [(1)] – North Sea	**1**	7	**1**	17
Deferred income tax	**(1,358)**	163	**(1,264)**	300
Income tax	**$ (1,281)**	$ 420	**$ (1,022)**	$ 711

(1) Petroleum Revenue Tax

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with further 1% rate reductions every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Six Months Ended Jun 30, 2019		
Issued common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of period	**1,201,886**	**$**	**9,323**
Issued upon exercise of stock options	**3,533**		**118**
Previously recognized liability on stock options exercised for common shares	**—**		**13**
Purchase of common shares under Normal Course Issuer Bid	**(17,100)**		**(134)**
Balance – end of period	**1,188,319**	**$**	**9,320**

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 6, 2019, the Board of Directors declared a quarterly dividend of $0.375 per common share, an increase from the previous quarterly dividend of $0.335 per common share.

Normal Course Issuer Bid

On May 21, 2019, 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 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's Normal Course Issuer Bid announced in May 2018 expired on May 22, 2019.

For the six months ended June 30, 2019, the Company purchased 17,100,000 common shares at a weighted average price of $36.95 per common share for a total cost of $632 million. Retained earnings were reduced by $498 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2019, the Company purchased 2,300,000 common shares at a weighted average price of $34.55 per common share for a total cost of $79 million.

Stock Options

The following table summarizes information relating to stock options outstanding at June 30, 2019:

	Six Months Ended Jun 30, 2019		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**46,685**	**$**	**37.92**
Granted	**11,028**	**$**	**35.88**
Surrendered for cash settlement	**(637)**	**$**	**35.02**
Exercised for common shares	**(3,533)**	**$**	**33.40**
Forfeited	**(1,899)**	**$**	**38.20**
Outstanding – end of period	**51,644**	**$**	**37.81**
Exercisable – end of period	**16,956**	**$**	**37.16**

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% 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 2019		Jun 30 2018
Derivative financial instruments designated as cash flow hedges	**$**	**39**	$	10
Foreign currency translation adjustment		**(12)**		2
	$	**27**	$	12

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 to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. 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. At June 30, 2019, the ratio was within the target range at 40.3%.

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 2019		Dec 31 2018
Long-term debt, net [(1)]	**$**	**23,109**	$	20,522
Total shareholders' equity	**$**	**34,274**	$	31,974
Debt to book capitalization		**40.3%**		39.1%

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

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%. At June 30, 2019, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended				Six Months Ended			
			Jun 30 2019		Jun 30 2018		**Jun 30 2019**		Jun 30 2018
Weighted average common shares outstanding – basic (thousands of shares)			**1,193,185**		1,226,021		**1,197,045**		1,225,820
Effect of dilutive stock options (thousands of shares)			**2,690**		6,486		**2,503**		6,279
Weighted average common shares outstanding – diluted (thousands of shares)			**1,195,875**		1,232,507		**1,199,548**		1,232,099
Net earnings		**$**	**2,831**	$	982	**$**	**3,792**	$	1,565
Net earnings per common share	– basic	**$**	**2.37**	$	0.80	**$**	**3.17**	$	1.28
	– diluted	**$**	**2.36**	$	0.80	**$**	**3.16**	$	1.27

15. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	Jun 30, 2019				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 2,124**	**$ —**	**$ —**	**$ —**	**$ 2,124**
Investments	**—**	**547**	**—**	**—**	**547**
Other long-term assets	**621**	**3**	**264**	**—**	**888**
Accounts payable	**—**	**—**	**—**	**(924)**	**(924)**
Accrued liabilities	**—**	**—**	**—**	**(2,360)**	**(2,360)**
Other long-term liabilities (1)	**—**	**(8)**	**(45)**	**(1,970)**	**(2,023)**
Long-term debt (2)	**—**	**—**	**—**	**(23,507)**	**(23,507)**
	$ 2,745	**$ 542**	**$ 219**	**$ (28,761)**	**$ (25,255)**

	Dec 31, 2018				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,148	$ —	$ —	$ —	$ 1,148
Investments	—	524	—	—	524
Other long-term assets	591	12	361	—	964
Accounts payable	—	—	—	(779)	(779)
Accrued liabilities	—	—	—	(2,356)	(2,356)
Other long-term liabilities (1)	—	(17)	—	(118)	(135)
Long-term debt (2)	—	—	—	(20,623)	(20,623)
	$ 1,739	$ 519	$ 361	$ (23,876)	$ (21,257)

(1) Includes $95 million of deferred purchase consideration payable over the next four years (December 31, 2018 - $118 million).

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

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's investments, recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

	Jun 30, 2019			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4) (5)
Investments (3)	**$ 547**	**$ 547**	**$ —**	**$ —**
Other long-term assets	**$ 888**	**$ —**	**$ 267**	**$ 621**
Other long-term liabilities	**$ (148)**	**$ —**	**$ (53)**	**$ (95)**
Fixed rate long-term debt (6) (7)	**$ (14,695)**	**$ (16,199)**	**$ —**	**$ —**

	Dec 31, 2018			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [4] [5]
Investments [3]	$ 524	$ 524	$ —	$ —
Other long-term assets	$ 964	$ —	$ 373	$ 591
Other long-term liabilities	$ (135)	$ —	$ (17)	$ (118)
Fixed rate long-term debt [6] [7]	$ (15,620)	$ (15,952)	$ —	$ —

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the short-term nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and purchase consideration payable), as well as lease liabilities, where carrying amount approximates fair value.

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair values of the investments are based on quoted market prices.

(4) The fair value of the deferred purchase consideration included in other long-term liabilities is based on the present value of future cash payments.

(5) The fair value of Redwater Partnership subordinated debt is based on the present value of future cash receipts.

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

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

Risk Management

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	Jun 30 2019	Dec 31 2018
Derivatives held for trading		
Foreign currency forward contracts	**$ (1)**	$ 8
Crude oil WCS [1] differential swaps	**(7)**	(17)
Natural gas AECO fixed price swaps	**3**	3
Natural gas AECO basis swaps	**—**	1
Cash flow hedges		
Foreign currency forward contracts	**(45)**	70
Cross currency swaps	**264**	291
	$ 214	$ 356
Included within:		
Current portion of other long-term assets	**$ 11**	$ 92
Current portion of other long-term liabilities	**(53)**	(17)
Other long-term assets	**256**	281
	$ 214	$ 356

(1) Western Canadian Select

For the six months ended June 30, 2019, the Company recognized a gain of $2 million (year ended December 31, 2018 – gain of $2 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value 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. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

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

Asset (liability)	Jun 30 2019	Dec 31 2018
Balance – beginning of period	$ 356	$ 101
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	2	35
Foreign exchange	(173)	260
Other comprehensive income (loss)	29	(40)
Balance – end of period	214	356
Less: current portion	(42)	75
	$ 256	$ 281

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

	Three Months Ended		Six Months Ended	
	Jun 30 2019	Jun 30 2018	Jun 30 2019	Jun 30 2018
Net realized risk management loss (gain)	$ 27	$ (27)	$ 54	$ (46)
Net unrealized risk management gain	(16)	(8)	(2)	(41)
	$ 11	$ (35)	$ 52	$ (87)

Financial Risk Factors

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 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.

At June 30, 2019, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term	Volume	Weighted average price	Index
Crude Oil				
WCS differential swaps	Jul 2019 - Sep 2019	8,000 bbl/d	US$23.57	WCS
Natural Gas				
AECO fixed price swaps	Jul 2019 - Oct 2019	115,000 GJ/d	$1.32	AECO

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At June 30, 2019, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based.

At June 30, 2019, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jul 2019	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Jul 2019	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at June 30, 2019 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at June 30, 2019, the Company had US$4,028 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,437 million designated as cash flow hedges.

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. At June 30, 2019, 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. At June 30, 2019, the Company had net risk management assets of $250 million with specific counterparties related to derivative financial instruments (December 31, 2018 – $361 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.

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	$	924	$	—	$	—	$	—
Accrued liabilities	$	2,360	$	—	$	—	$	—
Long-term debt (1)	$	3,970	$	4,046	$	8,100	$	7,511
Other long-term liabilities (2)	$	314	$	209	$	431	$	1,069
Interest and other financing expense (3)	$	977	$	840	$	1,830	$	5,126

(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, $236 million; one to less than two years, $184 million; two to less than five years, $386 million; and thereafter $1,069 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 at June 30, 2019.

16. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows (1):

		2019		2020		2021		2022		2023		Thereafter
Product transportation (2)	$	357	$	719	$	691	$	614	$	495	$	4,663
North West Redwater Partnership service toll (3)	$	36	$	126	$	157	$	158	$	157	$	2,858
Offshore vessels and equipment	$	57	$	89	$	64	$	9	$	—	$	—
Field equipment and power	$	22	$	20	$	21	$	20	$	21	$	274
Other	$	18	$	28	$	21	$	18	$	17	$	48

(1) Subsequent to the adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in note 15.

(2) The Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon in the second quarter of 2019.

(3) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the cost of service toll is $1,251 million of interest payable over the 30 year tolling period. See note 7.

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

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

17. SEGMENTED INFORMATION

	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended 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	
(millions of Canadian dollars, unaudited)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales																
Crude oil and NGLs	**2,297**	2,327	**4,136**	4,169	**211**	225	**345**	334	**203**	136	**312**	194	**2,711**	2,688	**4,793**	4,697
Natural gas	**249**	229	**624**	569	**11**	28	**36**	67	**18**	16	**36**	35	**278**	273	**696**	671
Other [1]	**3**	—	**5**	—	**2**	—	**2**	—	**2**	—	**3**	—	**7**	—	**10**	—
Total segmented product sales	**2,549**	2,556	**4,765**	4,738	**224**	253	**383**	401	**223**	152	**351**	229	**2,996**	2,961	**5,499**	5,368
Less: royalties	**(231)**	(263)	**(424)**	(438)	**(1)**	(1)	**(1)**	(1)	**(10)**	(15)	**(21)**	(20)	**(242)**	(279)	**(446)**	(459)
Segmented revenue	**2,318**	2,293	**4,341**	4,300	**223**	252	**382**	400	**213**	137	**330**	209	**2,754**	2,682	**5,053**	4,909
Segmented expenses																
Production	**571**	609	**1,173**	1,240	**100**	100	**167**	175	**24**	40	**42**	69	**695**	749	**1,382**	1,484
Transportation, blending and feedstock	**576**	699	**1,100**	1,433	**4**	6	**10**	12	**—**	—	**1**	1	**580**	705	**1,111**	1,446
Depletion, depreciation and amortization	**790**	780	**1,533**	1,558	**73**	72	**127**	116	**66**	42	**112**	70	**929**	894	**1,772**	1,744
Asset retirement obligation accretion	**21**	22	**41**	44	**8**	7	**15**	14	**2**	3	**3**	5	**31**	32	**59**	63
Risk management activities (commodity derivatives)	**(3)**	13	**29**	13	**—**	—	**—**	—	**—**	—	**—**	—	**(3)**	13	**29**	13
Gain on acquisition and revaluation of properties	**—**	—	**—**	—	**—**	(139)	**—**	(139)	**—**	—	**—**	—	**—**	(139)	**—**	(139)
Equity loss from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**1,955**	2,123	**3,876**	4,288	**185**	46	**319**	178	**92**	85	**158**	145	**2,232**	2,254	**4,353**	4,611
Segmented earnings (loss) before the following	**363**	170	**465**	12	**38**	206	**63**	222	**121**	52	**172**	64	**522**	428	**700**	298
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 expense																
Deferred income tax (recovery) expense																
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	
	2019	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales																
Crude oil and NGLs	**2,736**	3,266	**5,590**	6,464	**20**	25	**41**	52	**130**	92	**255**	161	**5,597**	6,071	**10,679**	11,374
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**46**	45	**84**	79	**324**	318	**780**	750
Other [(1)]	**3**	—	**3**	—	**—**	—	**—**	—	**—**	—	**—**	—	**10**	—	**13**	—
Total segmented product sales	**2,739**	3,266	**5,593**	6,464	**20**	25	**41**	52	**176**	137	**339**	240	**5,931**	6,389	**11,472**	12,124
Less: royalties	**(127)**	(158)	**(216)**	(239)	**—**	—	**—**	—	**—**	—	**—**	—	**(369)**	(437)	**(662)**	(698)
Segmented revenue	**2,612**	3,108	**5,377**	6,225	**20**	25	**41**	52	**176**	137	**339**	240	**5,562**	5,952	**10,810**	11,426
Segmented expenses																
Production	**814**	855	**1,636**	1,728	**5**	6	**11**	11	**19**	12	**34**	29	**1,533**	1,622	**3,063**	3,252
Transportation, blending and feedstock	**259**	323	**619**	648	**—**	—	**—**	—	**157**	114	**305**	200	**996**	1,142	**2,035**	2,294
Depletion, depreciation and amortization	**374**	372	**791**	776	**4**	4	**7**	7	**—**	—	**—**	—	**1,307**	1,270	**2,570**	2,527
Asset retirement obligation accretion	**15**	15	**31**	30	**—**	—	**—**	—	**—**	—	**—**	—	**46**	47	**90**	93
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(3)**	13	**29**	13
Gain on acquisition and revaluation of properties	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(139)	**—**	(139)
Equity loss from investments	**—**	—	**—**	—	**66**	2	**126**	3	**—**	—	**—**	—	**66**	2	**126**	3
Total segmented expenses	**1,462**	1,565	**3,077**	3,182	**75**	12	**144**	21	**176**	126	**339**	229	**3,945**	3,957	**7,913**	8,043
Segmented earnings (loss) before the following	**1,150**	1,543	**2,300**	3,043	**(55)**	13	**(103)**	31	**—**	11	**—**	11	**1,617**	1,995	**2,897**	3,383
Non–segmented expenses																
Administration													**84**	76	**154**	157
Share-based compensation													**(7)**	175	**55**	87
Interest and other financing expense													**197**	190	**388**	380
Risk management activities (other)													**14**	(48)	**23**	(100)
Foreign exchange (gain) loss													**(217)**	171	**(456)**	449
(Gain) loss from investments													**(4)**	29	**(37)**	134
Total non–segmented expenses													**67**	593	**127**	1,107
Earnings before taxes													**1,550**	1,402	**2,770**	2,276
Current income tax expense													**77**	257	**242**	411
Deferred income tax (recovery) expense													**(1,358)**	163	**(1,264)**	300
Net earnings													**2,831**	982	**3,792**	1,565

(1) 'Other' includes recoveries associated with the joint operation partners' share of the costs of lease contracts, and other income of a trivial nature.

Capital Expenditures (1)

	Six Months Ended					
	Jun 30, 2019			Jun 30, 2018		
	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 (3)	**$ 126**	**$ (149)**	**$ (23)**	$ 57	$ (81)	$ (24)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**35**	**—**	**35**	7	—	7
Oil Sands Mining and Upgrading	**—**	**—**	**—**	—	(7)	(7)
	$ 161	**$ (149)**	**$ 12**	$ 64	$ (88)	$ (24)
Property, plant and equipment						
Exploration and Production						
North America (3)	**$ 4,010**	**$ 1,025**	**$ 5,035**	$ 1,283	$ (101)	$ 1,182
North Sea	**78**	**105**	**183**	38	214	252
Offshore Africa (4)	**105**	**(1,490)**	**(1,385)**	62	—	62
	4,193	**(360)**	**3,833**	1,383	113	1,496
Oil Sands Mining and Upgrading (5)	**576**	**169**	**745**	470	(111)	359
Midstream and Refining	**5**	**—**	**5**	9	—	9
Head office	**18**	**(3)**	**15**	11	—	11
	$ 4,792	**$ (194)**	**$ 4,598**	$ 1,873	$ 2	$ 1,875

(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.

(3) Includes cash consideration paid of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in the second quarter of 2019.

(4) Offshore Africa includes a derecognition of $1,515 million following the FPSO demobilization at the Olowi field, Gabon in the first quarter of 2019.

(5) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

Segmented Assets

	Jun 30 2019	Dec 31 2018
Exploration and Production		
North America	**$ 32,180**	$ 27,199
North Sea	**1,774**	1,699
Offshore Africa	**1,599**	1,471
Other	**40**	33
Oil Sands Mining and Upgrading	**41,651**	39,634
Midstream and Refining	**1,491**	1,413
Head office	**220**	110
	$ 78,955	$ 71,559

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 2019. 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, 2019:	
Interest coverage (times)	
Net earnings (1)	5.8x
Adjusted funds flow (2)	12.1x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

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

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Corporate Information

Board of Directors

Catherine M. Best, FCA, ICD.D

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