Canadian Natural

SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2018 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2018 SECOND QUARTER RESULTS

Commenting on second quarter 2018 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "The Company's balanced strategy was once again evident in the quarter as our robust long life low decline asset base provided record quarterly funds flow of approximately $2.7 billion. The allocation of funds flow was balanced among our four pillars to maximize value for our shareholders through strengthening the balance sheet, returns to shareholders through dividends and share buybacks, economic resource development, and some minor opportunistic acquisitions year to date. The Company's ability to execute on our strategy is reflected in our second quarter results, and continues a long track record of strong results."

Canadian Natural's President, Tim McKay, added, "In the second quarter of 2018, operations were strong and cost control remained a focus, specifically at our Oil Sands Mining and Upgrading assets, where costs continue to come down. Operating costs of $22.94/bbl (US$17.77/bbl) of Synthetic Crude Oil ("SCO") were impressive given the successfully completed turnaround and pit stop activities in the quarter.

Canadian Natural's ability to effectively allocate capital was demonstrated in the quarter as we have made strategic and proactive decisions to take advantage of our large, balanced and diverse asset base due to changing market conditions. Our asset base is a key competitive advantage providing significant capital flexibility and as a result, to maximize value, we are shifting capital from primary heavy crude oil to light crude oil.

At Kirby North, top tier execution and strong productivity have resulted in accelerating the projects time line, bringing forward targeted first oil of the project's 40,000 bbl/d, by three months into Q4/19, one quarter earlier than originally planned.

At Horizon, the Company has identified opportunities to increase reliability, lower costs and add production growth of between 75,000 bbl/d and 95,000 bbl/d in the near and long term. The near term opportunities are targeted to add production growth of 35,000 bbl/d to 45,000 bbl/d of SCO. High grading of these near term opportunities and further defining of substantial long term growth opportunities is ongoing and is targeted to be completed by the end of the year. Additionally, early results from engineering and design specification work at the potential Paraffinic Froth Treatment expansion has indicated that the optimal production range for the expansion has increased by 10,000 bbl/d and is now targeted to add 40,000 bbl/d to 50,000 bbl/d. All of the these identified production growth opportunities at Horizon are over and above the previously disclosed annual corporate growth target of approximately 4% or 45,000 BOE/d of organic production over the next few years. These Horizon opportunities will be executed in a disciplined and step wise manner which preserves Canadian Natural's capital flexibility."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "In the second quarter of 2018, the strength of our asset base and effective and efficient operations delivered net earnings of $982 million and funds flow from operations of $2,706 million. Our strong financial results allowed the Company to further strengthen the balance sheet by decreasing absolute long term net debt by over $600 million from the previous quarter, and returning over $850 million to shareholders by way of dividends and share buybacks in the quarter.

The Company's acquisitions in 2017 were transformational and our results continue to show the accretive nature and resilience of these assets. Supported by successful expansions at Horizon, long life low decline and low capital exposure assets, we have been able to reduce long term net debt in the last 12 months since the Athabasca Oil Sands Project ("AOSP") acquisition by approximately $2,500 million, including the retirement of the deferred AOSP acquisition liability, improving our debt to book capitalization to 39.6% from 42.8% and debt to adjusted EBITDA to 2.1x from 3.4x over the same time frame, clearly demonstrating our commitment to strengthening the balance sheet."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2018	Mar 31 2018	Jun 30 2017	Six Months Ended Jun 30 2018	Jun 30 2017
Net earnings	**$ 982**	$ 583	$ 1,072	**$ 1,565**	$ 1,317
Per common share – basic	**$ 0.80**	$ 0.48	$ 0.93	**$ 1.28**	$ 1.16
– diluted	**$ 0.80**	$ 0.47	$ 0.93	**$ 1.27**	$ 1.16
Adjusted net earnings from operations (1)	**$ 1,279**	$ 885	$ 332	**$ 2,164**	$ 609
Per common share – basic	**$ 1.05**	$ 0.72	$ 0.29	**$ 1.77**	$ 0.54
– diluted	**$ 1.04**	$ 0.71	$ 0.29	**$ 1.76**	$ 0.54
Funds flow from operations (2)	**$ 2,706**	$ 2,323	$ 1,726	**$ 5,029**	$ 3,365
Per common share – basic	**$ 2.20**	$ 1.90	$ 1.50	**$ 4.10**	$ 2.97
– diluted	**$ 2.19**	$ 1.89	$ 1.49	**$ 4.08**	$ 2.95
Total net capital expenditures (3)	**$ 974**	$ 1,103	$ 13,046	**$ 2,077**	$ 13,892
Daily production, before royalties					
Natural gas (MMcf/d)	**1,539**	1,614	1,656	**1,576**	1,664
Crude oil and NGLs (bbl/d)	**793,899**	854,558	637,127	**824,060**	617,728
Equivalent production (BOE/d) (4)	**1,050,376**	1,123,546	913,171	**1,086,757**	895,139

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Funds flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

(3) 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 $982 million were realized in Q2/18, an increase of 68% over Q1/18 levels, and adjusted net earnings of $1,279 million were achieved, a 45% increase over Q1/18 levels.
- Canadian Natural generated record quarterly funds flow from operations of $2,706 million in Q2/18, increases of $383 million and $980 million from Q1/18 and Q2/17 levels respectively. The increase over Q1/18 and Q2/17 primarily reflects higher realized prices from the Company's liquids production together with higher liquids production volumes when compared to Q2/17.
- In Q2/18, Canadian Natural delivered funds flow from operations in excess of capital expenditures of approximately $1,730 million, an increase of approximately $510 million and $890 million from Q1/18 and Q2/17 levels respectively.
- In the first half of 2018, after dividend requirements, free cash flow totaled approximately $2,200 million.
- The Company maintained balance in the allocation of its funds flow from operations, consistent with the Company's four pillar strategy:
  - The Company remained disciplined in economic resource development with capital expenditures of $2,077 million in the first half of 2018.
  - In the first half of the year the Company has reduced long term net debt by $1,106 million, resulting in debt to adjusted EBITDA strengthening to 2.1x and debt to book capitalization improving to 39.6%.
  - Returns to shareholders remain a key focus for Canadian Natural as the Company has returned approximately $1,188 million by way of dividends and share buybacks in the first six months of 2018. Share buybacks for cancellation totaled 10,140,127 shares in Q2/18 at a weighted average share price of $43.52.

        - Subsequent to quarter end Canadian Natural declared a quarterly cash dividend on common shares of $0.335 per share payable on October 1, 2018.
        - Subsequent to quarter end, the Company executed additional share buybacks of 722,600 common shares for cancellation at a weighted average price of $46.95 per common share.
    - Opportunistic acquisitions have been minor in 2018, with year to date net expenditures of less than $100 million.

- The Company's production volumes in Q2/18 averaged 1,050,376 BOE/d, an increase of 15% from Q2/17 levels, mainly due to the Horizon Phase 3 expansion and acquisitions in 2017. Production decreased from Q1/18 levels by 7%, primarily as a result of major planned turnaround activities at the Company's Oil Sands Mining and Upgrading and thermal in situ operations as well as proactive and strategic actions taken to maximize value.
- Canadian Natural's corporate crude oil and NGL production volumes averaged 793,899 bbl/d, a decrease of 7% from Q1/18 levels and a 25% increase from Q2/17 levels. The decrease from Q1/18 was primarily as a result of proactive turnaround activities at our Oil Sands Mining and Upgrading and thermal in situ operations as well as curtailments in Q2/18. The increase from Q2/17 was primarily as a result of production from the Horizon Phase 3 expansion, as well as high reliability and strong production from acquisitions completed in 2017.
- At the Company's world class Oil Sands Mining and Upgrading assets, operations were as expected in Q2/18 with quarterly production of 407,704 bbl/d of Synthetic Crude Oil ("SCO"), a decrease of 11% from Q1/18 levels, as planned turnaround and pit stop activities at all three of the Company's oil sands mines, as well as a major 62 day turnaround at the Scotford Upgrader were successfully completed in the quarter.
    - Cost control remains a strong focus for the Company as costs continued to come down resulting in industry leading operating costs of $22.94/bbl (US$17.77/bbl) of SCO in Q2/18, a 2% decrease from Q2/17 levels and a 7% increase from Q1/18 levels, impressive results considering major turnarounds decreased production by 11% in Q2/18 from Q1/18 levels.
    - At the Athabasca Oil Sands Project ("AOSP"), a significant milestone was reached in July, when the asset produced its 1 billionth barrel of mined bitumen during its first 15 years of operations, one of the few world class assets to reach such a milestone. This is a true demonstration of the quality, size and scale of the Company's Oil Sands Mining and Upgrading operations which through environmentally responsible, safe, reliable, effective and efficient operations, provide sustainable long life low decline production and significant value for stakeholders.
    - At Horizon, following the successful completion of the Phase 3 expansion and after operating the plant for the last 8 months, the Company continues to evaluate potential expansions and has identified additional opportunities to increase reliability, lower costs and add production.
        - Results at the potential Paraffinic Froth Treatment expansion at Horizon are evident as the engineering and design specification work completed year to date has shown that the optimal production range of the proposed expansion has increased by 10,000 bbl/d and is now targeted to be 40,000 bbl/d to 50,000 bbl/d. The expansion is targeted to produce high quality diluted bitumen at significantly lower operating costs as the Company leverages its existing infrastructure. Preliminary estimates of the capital required for the proposed expansion are approximately $1.4 billion.
        - Defining and high grading additional opportunities is ongoing with the completion of the process targeted by year end. These opportunities are targeted to add near term growth of 35,000 bbl/d to 45,000 bbl/d of SCO. All opportunities will be executed in a disciplined and step wise manner, which preserves Canadian Natural's capital flexibility. The previously discussed Vacuum Gas Oil ("VGO") expansion will be included in the high grading process.
        - In preparation to execute on these opportunities in 2019 and 2020, Canadian Natural has increased 2018 capital expenditures guidance by $170 million to advance engineering and procurement of certain long lead equipment.
- At Kirby North, top tier execution and strong productivity has resulted in the project progressing ahead of schedule, advancing targeted first oil by three months into Q4/19, one quarter earlier than originally planned. Cost performance remains on budget with 95% of the Central Processing Facility equipment delivered to site and Steam Assisted Gravity Drainage ("SAGD") drilling nearing 45% completion. Kirby North targets to add 40,000 bbl/d of SAGD production.

- Balance sheet strength continues to be a focus of the Company and strong financial performance was demonstrated in Q2/18 through reduced long term debt and extensions of select credit facilities.
  - In Q2/18, Standard & Poor's revised the Company's rating outlook from BBB+/negative to BBB+/stable.
  - In Q2/18, the Company reduced absolute long term net debt by approximately $610 million, from Q1/18 levels.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances and committed bank credit facilities. At June 30, 2018 the Company had approximately $4,800 million of available liquidity, including cash and cash equivalents, an increase of approximately $800 million from Q1/18.
  - In Q2/18 Canadian Natural continued to have significant support from its large and diverse banking group as indicated by extensions of certain credit facilities completed in the quarter.
- In Q2/18 Canadian Natural published its 2017 Stewardship Report to Stakeholders, now available on the Company's website at https://www.cnrl.com/corporate-responsibility/stewardship-report/#2017. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing the Company's environmental footprint.

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 and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. This balance provides optionality for capital investments, facilitating improved 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 low decline, low reserves replacement costs, and effective and efficient operations means these assets provide substantial and sustainable funds flow throughout the commodity price cycle.

Augmenting this, Canadian Natural maintains a substantial inventory of low capital exposure projects within its 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 a major component of its operating cost 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 Jun 30			
	2018		2017	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**210**	**203**	236	216
Natural gas	**13**	**9**	16	16
Dry	**2**	**2**	3	3
Subtotal	**225**	**214**	255	235
Stratigraphic test / service wells	**555**	**477**	232	232
Total	**780**	**691**	487	467
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

- The Company's total Q2/18 crude oil and natural gas drilling program was 85 net wells, excluding strat/service wells, an increase of 17 net wells from the 68 net wells drilled in Q2/17. The Company's drilling levels reflects the disciplined capital allocation process and proactive actions to improve execution and control costs by balancing overall drilling levels throughout the year.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	June 30 2018	March 31 2018	June 30 2017	**June 30 2018**	June 30 2017
Crude oil and NGLs production (bbl/d)	**238,631**	245,609	227,083	**242,101**	229,325
Net wells targeting crude oil	**58**	101	57	**159**	204
Net successful wells drilled	**58**	99	55	**157**	202
Success rate	**100%**	98%	96%	**99%**	99%

- North America crude oil and NGLs averaged 238,631 bbl/d in Q2/18, within quarterly corporate guidance, representing a 3% decrease from Q1/18 levels and a 5% increase from Q2/17 levels. The volume decrease in Q2/18 compared to Q1/18 levels was primarily as a result of production curtailments and shut-in volumes of approximately 10,350 bbl/d as well as reduced drilling activity and delayed completion and ramp up of certain primary heavy crude oil wells drilled in Q1/18 and Q2/18.
- Due to current market conditions the Company has exercised its capital flexibility by shifting capital from primary heavy crude oil to light crude oil in 2018, resulting in an additional 7 net light crude oil wells targeted to be drilled in the second half of the year. Primary heavy crude oil drilling was reduced by 24 net primary heavy crude oil wells in Q2/18, with an additional 35 primary heavy crude oil well reduction targeted for the second half of the year.
- Canadian Natural's primary heavy crude oil production averaged 84,811 bbl/d in Q2/18, a 5% decrease from Q1/18 levels. In order to maximize value from the Company's primary heavy crude oil assets, Canadian Natural implemented and executed on proactive decisions and strategic actions in the first half of 2018, such as:
    - Disciplined capital allocation and proactive actions to target only the highest return wells in our primary heavy crude oil assets which resulted in 39 net wells drilled in Q2/18, less than originally budgeted.
    - The shut in of marginal high cost primary heavy crude oil production in 2018, which impacted Q2/18 production by approximately 2,900 bbl/d.
    - Proactive decisions to not sell marginal production in the wider spot WCS differential market versus the index WCS differential, caused by pipeline apportionment issues. As a result, the Company curtailed volumes of approximately 7,450 bbl/d in Q2/18.
  - Controlling costs remains a focus with operating costs of $17.02/bbl in Q2/18, comparable to Q1/18 levels, strong results given the lower production volumes that were primarily as a result of proactive curtailments.
  - At the Company's Smith primary heavy crude oil play, initial results have been strong from the 6 net multilateral wells drilled year to date and are currently producing approximately 340 bbl/d per well. There is significant potential at Smith for future development as Canadian Natural has 19 net sections in the fairway with the potential to add approximately 125 net horizontal multilateral primary heavy crude oil wells. Smith is an example of Canadian Natural's large, high quality primary heavy crude oil asset base.
- North America light crude oil and NGL quarterly production averaged 89,906 bbl/d, a decrease of 3% from Q1/18 levels and comparable to Q2/17 levels. Production from additional capital allocated to light crude oil assets is targeted to begin to be added in Q3/18.
  - The Company successfully drilled 38 net light crude oil wells in the first half of the year. Some initial results from wells coming on production in the quarter are as follows:
    - At the Company's light crude oil development at Tower, 7 net wells have been drilled and related facility construction has been completed. Operations are currently ramping up with initial well capacity targeted to be 850 bbl/d per well. Based on initial flow back rates, facility capacity of approximately 3,000 bbl/d is targeted to be reached in late Q3/18. There is additional potential at Tower with 41 targeted net light crude oil wells locations, on the Company's 11 net sections in the area.
    - At Wembley, 2 net Montney wells that were drilled in Q1/18 came on production late in Q2/18. Initial results are strong with production currently reaching approximately 800 bbl/d per well. There is meaningful potential at Wembley with 175 targeted net light crude oil well locations, on the Company's 77 net sections of Montney lands in the area.
  - Operating costs of $15.81/bbl were realized in Q2/18, comparable to Q1/18 levels in the Company's light crude oil and NGL areas.
- Pelican Lake quarterly production averaged 63,914 bbl/d, comparable with Q1/18 levels and an increase of 36% from Q2/17 levels. The increase from Q2/17 was as a result of the Company's successful integration of the acquired assets in 2017.
  - Polymer flood restoration on the acquired lands continues to proceed ahead of schedule, where approximately 60% of acquired lands are now under polymer flood. To optimize long term oil recovery and effectiveness of the polymer flood, the Company is using modified injection parameters in the near term. As polymer flood conformance improves, the Company expects to increase oil recovery and further maximize value.
  - Operating costs of $6.96/bbl were achieved in Q2/18, a 2% decrease from Q1/18 levels.

- In the quarter, the Company successfully drilled 11 net producer wells. When incorporating the 7 net wells drilled in Q1/18, the Company has drilled 18 net Pelican Lake wells in the first half of the year, which are performing as expected and are currently producing approximately 90 bbl/d per well**.**

▪ The Company's 2018 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 253,000 bbl/d - 263,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Bitumen production (bbl/d)	**104,907**	111,851	105,719	**108,359**	116,983
Net wells targeting bitumen	**21**	22	4	**43**	12
Net successful wells drilled	**21**	22	4	**43**	12
Success rate	**100%**	100%	100%	**100%**	100%

▪ Thermal in situ quarterly production volumes averaged 104,907 bbl/d, within Q2/18 guidance and a decrease of 6% as expected from Q1/18 levels primarily as the Company advanced and completed turnaround activities in the quarter. Production curtailments impacted Q2/18 by approximately 700 bbl/d, mainly at Kirby South.

- At Primrose, Q2/18 production volumes averaged 67,569 bbl/d, a decrease of 6% from Q1/18 levels, primarily as a result of major turnaround activities. Including energy costs, operating costs were strong at $14.66/bbl in Q2/18, a decrease of 12% and 8% from Q1/18 and Q2/17 levels respectively, excellent results given downtime relating to the turnarounds in the quarter.
  - Pad additions at Primrose are going as planned with the drilling targeted to add approximately 32,000 bbl/d in 2020, with initial production targeted late in 2019. These pad additions are high return activities as the Company utilizes available oil processing and steam capacity.
- At Kirby South, SAGD production volumes of 35,322 bbl/d were achieved in Q2/18, a decrease of 5% from Q1/18 levels following planned turnaround activities brought forward into Q2/18 and curtailments of approximately 700 bbl/d and a 2% increase from Q2/17 levels.
  - Including energy costs, Kirby South achieved strong Q2/18 operating costs of $9.12/bbl, comparable to Q1/18 and a decrease of 11% from Q2/17 levels.
- At Kirby North, top tier execution and strong productivity has resulted in the project progressing ahead of schedule, advancing targeted first oil by three months into Q4/19, one quarter earlier than originally planned. Cost performance remains on budget with 95% of the Central Processing Facility equipment delivered to site and SAGD drilling nearing 45% completion. Kirby North targets to add 40,000 bbl/d of SAGD production.

▪ The Company's 2018 thermal in situ annual production guidance remains unchanged and is targeted to range between 107,000 bbl/d - 127,000 bbl/d.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Natural gas production (MMcf/d)	**1,485**	1,547	1,603	**1,515**	1,607
Net wells targeting natural gas	**4**	5	5	**9**	17
Net successful wells drilled	**4**	5	5	**9**	16
Success rate	**100%**	100%	100%	**100%**	94%

▪ North America natural gas production was as expected at 1,485 MMcf/d in Q2/18, representing decreases of 4% and 7% from Q1/18 and Q2/17 levels respectively.

- Operating costs of $1.28/Mcf were realized in Q2/18, a decrease of 2% from Q1/18 levels, strong results given lower natural gas volumes due to the Company's proactive decision to shut-in volumes and delay activity on certain natural gas assets.

- In Q2/18 the Company has made the following proactive and strategic actions to maximize value in the Company's natural gas assets, including:

  - Completion of major turnaround activities at natural gas processing facilities to correspond with challenged natural gas prices.
  - Deferred capital and development activity including recompletions and workovers of certain natural gas assets, resulting in a production impact of approximately 20 MMcf/d in Q2/18. The Company will look to execute these deferrals in Q3/18 or Q4/18 with improved natural gas prices.
  - Q2/18 production volumes of approximately 27 MMcf/d were shut-in, due to low natural gas prices.
  - Q2/18 production was impacted by 12 MMcf/d related to solution gas associated with the curtailment of primary heavy crude oil production.

- Additionally, the Company's natural gas production was reduced by approximately 65 MMcf/d in Q2/18 due to restrictions at the Pine River plant, operated by a third party. In Q2/18 Canadian Natural, subject to regulatory approval, agreed to acquire the facility from the third party, which needs to complete a meter upgrade that will take approximately four weeks, at which time the Company targets to complete maintenance work on the facility and will assess increasing plant throughput and reliability to match field capacity of approximately 145 MMcf/d.

- As a result of the items listed above and proactive actions going forward, the Company's 2018 corporate natural gas annual production guidance has been revised and is targeted to range from 1,550 MMcf/d - 1,600 MMcf/d.

- The Company uses natural gas in its operations representing approximately 35% of its total equivalent gas production providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 32% of the natural gas production is exported to other North American markets or sold internationally, with the remaining 33% of the Company's production being exposed to AECO/Station 2 pricing.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil production (bbl/d)					
North Sea	**24,456**	21,584	26,304	**23,028**	24,682
Offshore Africa	**18,201**	19,438	20,480	**18,816**	21,542
Natural gas production (MMcf/d)					
North Sea	**30**	37	37	**34**	37
Offshore Africa	**24**	30	16	**27**	20
Net wells targeting crude oil	**1.9**	1.0	1.8	**2.9**	1.8
Net successful wells drilled	**1.9**	1.0	1.8	**2.9**	1.8
Success rate	**100%**	100%	100%	**100%**	100%

- International E&P quarterly production volumes were within quarterly production guidance and reached 42,657 bbl/d in Q2/18, an increase of 4% from Q1/18 levels.

  - In the North Sea, volumes of 24,456 bbl/d were achieved in Q2/18, an increase of 13% from Q1/18 levels and a decrease of 7% from Q2/17 levels. The increase in production in Q2/18 from Q1/18 levels was primarily due to new wells at Tiffany and Ninian. The decrease from Q2/17 levels was a result of the impact of the shut-in of the Ninian North platform in May 2017 in preparation for decommissioning and natural field declines, partially offset by new wells at Ninian South and production optimization.

- The Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea resulted in Q2/18 operating costs decreasing by 19% from Q1/18 levels to $35.12/bbl.
- In the first half of 2018, 2.9 net wells were drilled in the North Sea, with current light crude oil production exceeding 1,700 bbl/d per well.
- On April 26, 2018, the Ninian North platform was permanently de-manned in readiness for future removal as part of the ongoing decommissioning program. This milestone was achieved 3 months ahead of schedule and below budget.

- Offshore Africa production volumes in Q2/18 averaged 18,201 bbl/d, a decrease of 6% and 11% from Q1/18 and Q2/17 levels respectively. The decrease from Q2/17 was primarily as a result of planned maintenance activities at Espoir that were successfully completed in Q2/18, as well as natural field declines.
  - Côte d'Ivoire crude oil operating costs in Q2/18 were strong at $16.39/bbl, a 5% decrease from Q2/17 levels.
  - The Company is targeting to drill 1.7 net producing wells at Baobab, where drilling has commenced. The program targets to add average net production of approximately 5,700 bbl/d of light crude oil with the first well targeted to come on production in late Q3/18.

- The Company's 2018 International annual production guidance remains unchanged and is targeted to range from 40,000 bbl/d - 45,000 bbl/d.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Synthetic crude oil production (bbl/d) (1) (2)	**407,704**	456,076	257,541	**431,756**	225,196

(1) Q2/18 SCO production before royalties excludes 3,026 bbl/d of SCO consumed internally as diesel (Q1/18 – 3,224 bbl/d; Q2/17 – 438 bbl/d).

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

- At the Company's world class Oil Sands Mining and Upgrading assets, operations were as expected in Q2/18 with quarterly production of 407,704 bbl/d of SCO, a decrease of 11% from Q1/18 levels as planned turnaround and pit stop activities at all three of the Company's oil sands mines as well as a major 62 day turnaround at the Scotford Upgrader were successfully completed in the quarter.
  - Cost control remains a strong focus for the Company as costs continued to come down resulting in industry leading operating costs of $22.94/bbl (US$17.77/bbl) of SCO in Q2/18, a 2% decrease from Q2/17 levels and a 7% increase from Q1/18 levels, impressive results considering major turnarounds decreased production by 11% in Q2/18 from Q1/18 levels.
  - At the AOSP, a significant milestone was reached in July, when the asset produced its 1 billionth barrel of mined bitumen during its first 15 years of operations, one of the few world class assets to reach such a milestone. This is a true demonstration of the quality, size and scale of the Company's Oil Sands Mining and Upgrading operations which through environmentally responsible, safe, reliable, effective and efficient operations, provide sustainable long life low decline production and significant value for stakeholders.
  - At Horizon, following the successful completion of the Phase 3 expansion and after operating the plant for the last 8 months, the Company continues to evaluate potential expansions and has identified additional opportunities to increase reliability, lower costs and add production.
    - Results at the potential Paraffinic Froth Treatment expansion at Horizon are evident as the engineering and design specification work completed year to date has shown that the optimal production range of the proposed expansion has increased by 10,000 bbl/d and is now targeted to be 40,000 bbl/d to 50,000 bbl/d. The expansion is targeted to produce high quality diluted bitumen at significantly lower operating costs as the Company leverages its existing infrastructure. Preliminary estimates of the capital required for the proposed expansion are approximately $1.4 billion.
    - Defining and high grading additional opportunities is ongoing with the completion of the process targeted by year end. These opportunities are targeted to add near term growth of 35,000 bbl/d to 45,000 bbl/d of SCO. All opportunities will be executed in a disciplined and step wise manner, which preserves Canadian Natural's capital flexibility. The previously discussed VGO expansion will be included in the high grading process.

- ◦ The Company's planned 21 day turnaround is targeted for September 2018. Subsequently, the plant will run at restricted rates of approximately 130,000 bbl/d for 12 days to perform maintenance on the Vacuum Distillate Unit ("VDU") furnaces.

- The Company's 2018 Oil Sands Mining and Upgrading annual production guidance remains unchanged and is targeted to range from 415,000 bbl/d - 450,000 bbl/d of upgraded products.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 67.90**	$ 62.89	$ 48.29	**$ 65.41**	$ 50.07
WCS heavy differential as a percentage of WTI (%) (2)	**28%**	39%	23%	**33%**	26%
SCO price (US$/bbl)	**$ 67.27**	$ 61.45	$ 49.83	**$ 64.38**	$ 50.63
Condensate benchmark pricing (US$/bbl)	**$ 68.85**	$ 63.12	$ 48.44	**$ 66.00**	$ 50.31
Average realized pricing before risk management (C$/bbl) (3)	**$ 61.14**	$ 43.06	$ 47.12	**$ 52.32**	$ 47.08
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 0.97**	$ 1.75	$ 2.63	**$ 1.36**	$ 2.71
Average realized pricing before risk management (C$/Mcf)	**$ 1.95**	$ 2.74	$ 2.97	**$ 2.35**	$ 3.11

(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.

- In Q2/18, the WCS heavy differential narrowed as heavy crude oil began to be moved to market. The WCS heavy differential widened in Q1/18 as a result of third party pipeline outages backing up heavy crude oil into Western Canada. This resulted in anomalous heavy crude oil pricing as the pipeline operators and rail transport worked to remove the backlog of inventory.

- Canadian Natural and other industry participants, as part of a working committee, are working towards a more effective nomination process that verifies actual production and sales.

  - Having an effective nomination process is significant to Canadian Natural as the Company is required to sell portions of its heavy crude oil production at a discount to the WCS index as a result of apportionment on the Enbridge pipeline.

- AECO natural gas prices for Q2/18 continued to reflect third party pipeline constraints limiting flow of natural gas to export markets, increased natural gas production in the basin and constraints on export capacity out of Western Canada.

- The North West Redwater ("NWR") refinery, upon completion, will 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 North West Redwater refinery began processing light crude oil late in November 2017 and continues to progress as expected.

  - The Company has a 50% interest in the NWR Partnership. For updates on the project, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.

2017 Stewardship Report to Stakeholders

In Q2/18 Canadian Natural published its 2017 Stewardship Report to Stakeholders, now available on the Company's website at https://www.cnrl.com/corporate-responsibility/stewardship-report/#2017. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint.

- 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 has carbon capture facilities at 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 570,000 vehicles off the road, making the Company the 5th largest capturer and sequester of CO_2 globally once the NWR refinery is fully running.
- At Canadian Natural's Oil Sands operations, which represent approximately 66% of the Company's liquids production, the Company's emissions intensity is only approximately 5% higher than the average intensity for all global crude oils. By investing in and leveraging technology, specifically carbon capture initiatives, Canadian Natural has developed a pathway to reduce the Company's greenhouse gas ("GHG") emissions intensity to be below the average for global crude oils.
- 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 Company’s GHG emissions intensity has decreased materially by 18% from 2013 to 2017.
- Methane emissions have decreased 71% from 2013 to 2017 at the Company's Alberta primary heavy crude oil operations.

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 funds flow generation, credit facilities, US commercial paper program, 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 1,050,376 BOE/d in Q2/18, with approximately 98% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with current approximate product mix on a BOE/d basis of 50% light crude oil and SCO blends, 25% heavy crude oil blends and 25% natural gas, based upon the midpoint of annual 2018 production guidance.
  - Canadian Natural’s production is resilient as long life low decline assets make up approximately 73% of 2018 liquids production guidance, including the AOSP, Horizon, Pelican Lake and thermal in situ oil sands assets.
- In Q2/18, Canadian Natural delivered funds flow from operations in excess of capital expenditures of approximately $1,730 million, an increase of approximately $510 million and $890 million from Q1/18 and Q2/17 levels respectively.
- Balance sheet strength continues to be a focus of the Company and strong financial performance was demonstrated in Q2/18 through reduced long term debt and extensions of select credit facilities.
  - In Q2/18, Standard & Poor's revised the Company's rating outlook from BBB+/negative to BBB+/stable.
  - In Q2/18, the Company reduced long term net debt by approximately $610 million, from Q1/18 levels.
    - Additionally, the Company has reduced long term debt in the past 12 months since the AOSP acquisition by approximately $2,500 million, from Q2/17 levels, when including the retirement of the deferred AOSP acquisition liability.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances and committed bank credit facilities. At June 30, 2018 the Company had approximately $4,800 million of available liquidity, including cash and cash equivalents, an increase of approximately $800 million from Q1/18.
  - Canadian Natural continues to have significant support from its large and diverse banking group as indicated by credit facility extensions during the quarter. In Q2/18 the Company extended its $2,425 million revolving syndicated

credit facility originally maturing in June 2020 to June 2022. Additionally in the quarter, Canadian Natural's $2,200 million non-revolving facility was extended from October 2019 to October 2020.

  - As at June 30, 2018, debt to book capitalization improved to 39.6% from 40.5% in Q1/18 and debt to adjusted EBITDA strengthened to 2.1x from 2.5x from Q1/18.

- Returns to shareholders remains a key focus for Canadian Natural as the Company returned approximately $850 million by way of dividend and share buybacks in Q2/18. Share buybacks for cancellation totaled 10,140,127 shares in the quarter at an weighted average share price of $43.52.
  - Subsequent to quarter end, the Company had additional share buybacks of 722,600 common shares for cancellation at a weighted average price of $46.95 per common share.
- In addition to its strong 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, 2018, these financial levers include the Company's third party equity investments of approximately $745 million.
- Subsequent to quarter end, Canadian Natural declared a quarterly cash dividend on common shares of $0.335 per share payable on October 1, 2018.

OUTLOOK

The Company forecasts annual 2018 production levels to average between 815,000 and 885,000 bbl/d of crude oil and NGLs and between 1,550 and 1,600 MMcf/d of natural gas, before royalties. Q3/18 production guidance before royalties is forecast to average between 771,000 and 819,000 bbl/d of crude oil and NGLs and between 1,535 and 1,565 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 2018 capital expenditures are targeted to be approximately $4.6 billion.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

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") operations and future expansions, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing of construction 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 or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, and the assumption of operations at processing facilities also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is 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 natural gas liquids ("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 reserve 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 reserve 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 material 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 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.

Management’s Discussion and Analysis

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and six months ended June 30, 2018 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2017.

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, 2018 and this MD&A have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board. 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; funds flow from operations and cash production costs. These financial measures are not defined by 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 and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and funds flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the “Financial Highlights” section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of this MD&A.

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. 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 volumes and per unit statistics are presented throughout this MD&A on a “before royalty” or “gross” basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. Production on an “after royalty” or “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, 2018 in relation to the comparable periods in 2017 and the first quarter of 2018. 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, 2017, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated August 1, 2018.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Jun 30 2018**	Mar 31 2018	Jun 30 2017	Six Months Ended **Jun 30 2018**	Jun 30 2017
Product sales	**$ 6,389**	$ 5,735	$ 4,127	**$ 12,124**	$ 8,119
Crude oil and NGLs	**$ 6,071**	$ 5,303	$ 3,645	**$ 11,374**	$ 7,104
Natural gas	**$ 318**	$ 432	$ 482	**$ 750**	$ 1,015
Net earnings	**$ 982**	$ 583	$ 1,072	**$ 1,565**	$ 1,317
Per common share – basic	**$ 0.80**	$ 0.48	$ 0.93	**$ 1.28**	$ 1.16
– diluted	**$ 0.80**	$ 0.47	$ 0.93	**$ 1.27**	$ 1.16
Adjusted net earnings from operations (1)	**$ 1,279**	$ 885	$ 332	**$ 2,164**	$ 609
Per common share – basic	**$ 1.05**	$ 0.72	$ 0.29	**$ 1.77**	$ 0.54
– diluted	**$ 1.04**	$ 0.71	$ 0.29	**$ 1.76**	$ 0.54
Funds flow from operations (2)	**$ 2,706**	$ 2,323	$ 1,726	**$ 5,029**	$ 3,365
Per common share – basic	**$ 2.20**	$ 1.90	$ 1.50	**$ 4.10**	$ 2.97
– diluted	**$ 2.19**	$ 1.89	$ 1.49	**$ 4.08**	$ 2.95
Net capital expenditures	**$ 974**	$ 1,103	$ 13,046	**$ 2,077**	$ 13,892

(1) 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 certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented in this MD&A, presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) Funds flow from operations is a non-GAAP measure that represents net earnings as presented in the Company's consolidated Statements of Earnings, adjusted for certain non-cash items. The Company evaluates its performance based on funds flow from operations. The Company considers funds flow from operations 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 "Funds Flow from Operations, as Reconciled to Net Earnings" presented in this MD&A, includes certain non-cash items that are disclosed in the Company's financial results as presented in the Company's consolidated Statements of Cash Flows. Funds flow from operations may not be comparable to similar measures presented by other companies.

Funds flow from operations can also be derived by adjusting the GAAP measure Cash Flows from Operating Activities presented in the Company's consolidated Statements of Cash Flows for the net change in non-cash working capital, and abandonment and other expenditures. Accordingly, the Company has provided a second reconciliation, "Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities" in this MD&A.

Adjusted Net Earnings from Operations

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Net earnings	***$ 982***	*$ 583*	*$ 1,072*	***$ 1,565***	*$ 1,317*
Share-based compensation, net of tax (1)	***175***	*(88)*	*(104)*	***87***	*(77)*
Unrealized risk management (gain) loss, net of tax (2)	***(11)***	*(31)*	*2*	***(42)***	*(29)*
Unrealized foreign exchange loss (gain), net of tax (3)	***178***	*162*	*(355)*	***340***	*(415)*
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	***—***	*146*	*—*	***146***	*—*
Loss (gain) from investments, net of tax (5) (6)	***38***	*113*	*(27)*	***151***	*69*
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	***(83)***	*—*	*(256)*	***(83)***	*(256)*
Adjusted net earnings from operations	***$ 1,279***	*$ 885*	*$ 332*	***$ 2,164***	*$ 609*

(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) Oil Sands Mining and Upgrading.

(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 (gain) from investments is the Company's pro rata share of the Redwater Partnership's accounting loss (gain) 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 remeasured 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 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. During the second quarter of 2017, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment.

Funds Flow from Operations, as Reconciled to Net Earnings

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Net earnings	***$ 982***	*$ 583*	*$ 1,072*	***$ 1,565***	*$ 1,317*
Non-cash items:					
Depletion, depreciation and amortization	***1,270***	*1,257*	*1,210*	***2,527***	*2,509*
Share-based compensation	***175***	*(88)*	*(104)*	***87***	*(77)*
Asset retirement obligation accretion	***47***	*46*	*39*	***93***	*75*
Unrealized risk management gain	***(8)***	*(33)*	*(6)*	***(41)***	*(46)*
Unrealized foreign exchange loss (gain)	***178***	*162*	*(355)*	***340***	*(415)*
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax	**—**	*146*	—	***146***	—
Loss (gain) from investments	***38***	*113*	*(27)*	***151***	*69*
Deferred income tax expense	***163***	*137*	*162*	***300***	*198*
Gain on acquisition, disposition and revaluation of properties	***(139)***	—	*(265)*	***(139)***	*(265)*
Funds flow from operations	***$ 2,706***	*$ 2,323*	*$ 1,726*	***$ 5,029***	*$ 3,365*

Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Cash flows from operating activities	***$ 2,613***	*$ 2,469*	*$ 1,631*	***$ 5,082***	*$ 3,302*
Net change in non-cash working capital	***57***	*(235)*	*(39)*	***(178)***	*(90)*
Abandonment expenditures	***50***	*90*	*105*	***140***	*146*
Other	***(14)***	*(1)*	*29*	***(15)***	*7*
Funds flow from operations	***$ 2,706***	*$ 2,323*	*$ 1,726*	***$ 5,029***	*$ 3,365*

SUMMARY OF CONSOLIDATED NET EARNINGS AND FUNDS FLOW FROM OPERATIONS

Net earnings for the six months ended June 30, 2018 were $1,565 million compared with net earnings of $1,317 million for the six months ended June 30, 2017. Net earnings for the six months ended June 30, 2018 included net after-tax expenses of $599 million compared with net after-tax income of $708 million for the six months ended June 30, 2017 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, loss from investments, and gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2018 were $2,164 million compared with adjusted net earnings of $609 million for the six months ended June 30, 2017.

Net earnings for the second quarter of 2018 were $982 million compared with net earnings of $1,072 million for the second quarter of 2017 and net earnings of $583 million for the first quarter of 2018. Net earnings for the second quarter of 2018 included net after-tax expenses of $297 million compared with net after-tax income of $740 million for the second quarter of 2017 and net after-tax expenses of $302 million for the first quarter of 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 repayment of long-term debt, loss (gain) from investments, and gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the second quarter of 2018 were $1,279 million compared with adjusted net earnings of $332 million for the second quarter of 2017 and adjusted net earnings of $885 million for the first quarter of 2018.

The increase in adjusted net earnings for the three and six months ended June 30, 2018 from the three and six months ended June 30, 2017 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and Phase 3 sales volumes at Horizon;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment; and
- higher crude oil and NGLs netbacks in the Exploration and Production segments;

partially offset by:

- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the North America Exploration and Production segment;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

The increase in adjusted net earnings for the second quarter of 2018 from the first quarter of 2018 was primarily due to:

- higher crude oil and NGLs netbacks in the Exploration and Production segments;
- higher crude oil and NGLs sales volumes in the International segment; and
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to the planned maintenance activities at Horizon and AOSP;
- lower natural gas netbacks in the Exploration and Production segments; and
- higher depletion, depreciation and amortization.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Funds flow from operations for the six months ended June 30, 2018 was $5,029 million compared with $3,365 million for the six months ended June 30, 2017. Funds flow from operations for the second quarter of 2018 was $2,706 million compared with $1,726 million for the second quarter of 2017 and $2,323 million for the first quarter of 2018. The fluctuations in funds flow from operations from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings, as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the second quarter of 2018 increased 15% to 1,050,376 BOE/d from 913,171 BOE/d for the second quarter of 2017 and decreased 7% from 1,123,546 BOE/d for the first quarter of 2018.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)	**Jun 30 2018**	Mar 31 2018	Dec 31 2017	Sep 30 2017
Product sales [1]	**$ 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
($ millions, except per common share amounts)	Jun 30 2017	Mar 31 2017	Dec 31 2016	Sep 30 2016
Product sales [1]	$ 4,127	$ 3,992	$ 3,672	$ 2,477
Crude oil and NGLs	$ 3,645	$ 3,459	$ 3,193	$ 2,106
Natural gas	$ 482	$ 533	$ 479	$ 371
Net earnings (loss)	$ 1,072	$ 245	$ 566	$ (326)
Net earnings (loss) per common share				
– basic	$ 0.93	$ 0.22	$ 0.51	$ (0.29)
– diluted	$ 0.93	$ 0.22	$ 0.51	$ (0.29)

(1) Comparative figures for product sales in 2016 are reported in accordance with the Company's presentation prior to adoption of IFRS 15 on January 1, 2018. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15.

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 and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third party pipeline maintenance 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, fluctuations in the Company’s drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, new production from Horizon Phase 2B and Phase 3, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, shut-in production due to low commodity prices, and the impact of the drilling program in the International segments. 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 a third party 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, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **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, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, and the impact of turnarounds at Horizon.
- **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 impacted the realized price the Company received 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 include 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 gains on the acquisition of AOSP and other assets, 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) in Redwater Partnership.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended Jun 30 2018	Mar 31 2018	Jun 30 2017	Six Months Ended Jun 30 2018	Jun 30 2017
WTI benchmark price (US$/bbl)	**$ 67.90**	$ 62.89	$ 48.29	**$ 65.41**	$ 50.07
Dated Brent benchmark price (US$/bbl)	**$ 74.51**	$ 66.99	$ 50.24	**$ 70.77**	$ 52.14
WCS heavy differential from WTI (US$/bbl)	**$ 19.24**	$ 24.27	$ 11.11	**$ 21.74**	$ 12.84
SCO price (US$/bbl)	**$ 67.27**	$ 61.45	$ 49.83	**$ 64.38**	$ 50.63
Condensate benchmark price (US$/bbl)	**$ 68.85**	$ 63.12	$ 48.44	**$ 66.00**	$ 50.31
NYMEX benchmark price (US$/MMBtu)	**$ 2.80**	$ 2.98	$ 3.18	**$ 2.89**	$ 3.25
AECO benchmark price (C$/GJ)	**$ 0.97**	$ 1.75	$ 2.63	**$ 1.36**	$ 2.71
US/Canadian dollar average exchange rate (US$)	**$ 0.7746**	$ 0.7905	$ 0.7436	**$ 0.7824**	$ 0.7495

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.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$65.41 per bbl for the six months ended June 30, 2018, an increase of 31% from US$50.07 per bbl for the six months ended June 30, 2017. WTI averaged US$67.90 per bbl for the second quarter of 2018, an increase of 41% from US $48.29 per bbl for the second quarter of 2017, and an increase of 8% from US$62.89 per bbl for the first quarter of 2018.

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$70.77 per bbl for the six months ended June 30, 2018, an increase of 36% from US$52.14 per bbl for the six months ended June 30, 2017. Brent averaged US$74.51 per bbl for the second quarter of 2018, an increase of 48% from US$50.24 per bbl for the second quarter of 2017, and an increase of 11% from US$66.99 per bbl for the first quarter of 2018.

WTI and Brent pricing for the three and six months ended June 30, 2018 has increased from the comparable periods due to declines in global crude oil inventories, together with larger than anticipated increases in global demand for crude oil.

The WCS heavy differential averaged US$21.74 per bbl for the six months ended June 30, 2018, an increase of 69% from US$12.84 per bbl for the six months ended June 30, 2017. The WCS heavy differential averaged US$19.24 per bbl for the second quarter of 2018, an increase of 73% from US$11.11 per bbl for the second quarter of 2017, and a decrease of 21% from US$24.27 per bbl for the first quarter of 2018. The widening of the WCS heavy differential for the three and six months ended June 30, 2018 from the comparable periods in 2017 reflected changes in transportation logistics and the impact of the third party pipeline outage in the fourth quarter of 2017. The narrowing of the differential for the second quarter of 2018 compared with the first quarter of 2018 reflected seasonal supply and demand factors.

The SCO price averaged US$64.38 per bbl for the six months ended June 30, 2018, an increase of 27% from US$50.63 per bbl for the six months ended June 30, 2017. The SCO price averaged US$67.27 per bbl for the second quarter of 2018, an increase of 35% from US$49.83 per bbl for the second quarter of 2017, and an increase of 9% from US$61.45 per bbl for the first quarter of 2018. The increase in SCO pricing for the three and six months ended June 30, 2018 from the comparable periods was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.89 per MMBtu for the six months ended June 30, 2018, a decrease of 11% from US$3.25 per MMBtu for the six months ended June 30, 2017. NYMEX natural gas prices averaged US$2.80 per MMBtu for the second quarter of 2018, a decrease of 12% from US$3.18 per MMBtu for the second quarter of 2017, and a decrease of 6% from US$2.98 per MMBtu for the first quarter of 2018.

AECO natural gas prices averaged $1.36 per GJ for the six months ended June 30, 2018, a decrease of 50% from $2.71 per GJ for the six months ended June 30, 2017. AECO natural gas prices averaged $0.97 per GJ for the second quarter of 2018, a decrease of 63% from $2.63 per GJ for the second quarter of 2017, and a decrease of 45% from $1.75 per GJ for the first quarter of 2018.

The decrease in natural gas prices for the three and six months ended June 30, 2018 from the comparable periods in 2017 continued to reflect third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the basin. The decrease in natural gas prices for the second quarter of 2018 compared with the first quarter of 2018 reflected the third party pipeline constraints as well as seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**343,538**	357,460	332,802	**350,460**	346,308
North America – Oil Sands Mining and Upgrading [(1)]	**407,704**	456,076	257,541	**431,756**	225,196
North Sea	**24,456**	21,584	26,304	**23,028**	24,682
Offshore Africa	**18,201**	19,438	20,480	**18,816**	21,542
	793,899	854,558	637,127	**824,060**	617,728
Natural gas (MMcf/d)					
North America	**1,485**	1,547	1,603	**1,515**	1,607
North Sea	**30**	37	37	**34**	37
Offshore Africa	**24**	30	16	**27**	20
	1,539	1,614	1,656	**1,576**	1,664
Total barrels of oil equivalent (BOE/d)	**1,050,376**	1,123,546	913,171	**1,086,757**	895,139
Product mix					
Light and medium crude oil and NGLs	**13%**	12%	15%	**12%**	15%
Pelican Lake heavy crude oil	**6%**	6%	5%	**6%**	5%
Primary heavy crude oil	**8%**	8%	10%	**8%**	10%
Bitumen (thermal oil)	**10%**	10%	12%	**10%**	13%
Synthetic crude oil	**39%**	40%	28%	**40%**	26%
Natural gas	**24%**	24%	30%	**24%**	31%
Percentage of gross revenue [(1) (2)] (excluding Midstream revenue)					
Crude oil and NGLs	**95%**	92%	88%	**94%**	87%
Natural gas	**5%**	8%	12%	**6%**	13%

(1) Second quarter 2018 SCO production before royalties excludes 3,026 bbl/d of SCO consumed internally as diesel (first quarter 2018 – 3,224 bbl/d; second quarter 2017 – 438 bbl/d; six months ended June 30, 2018 – 3,125 bbl/d; six months ended June 30, 2017 – 433 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**293,080**	310,783	291,716	**301,883**	302,334
North America – Oil Sands Mining and Upgrading	**385,986**	443,606	251,623	**414,171**	220,575
North Sea	**24,411**	21,521	26,246	**22,974**	24,632
Offshore Africa	**16,502**	18,652	19,231	**17,571**	20,461
	719,979	794,562	588,816	**756,599**	568,002
Natural gas (MMcf/d)					
North America	**1,407**	1,473	1,528	**1,439**	1,515
North Sea	**30**	37	37	**34**	37
Offshore Africa	**20**	27	15	**23**	18
	1,457	1,537	1,580	**1,496**	1,570
Total barrels of oil equivalent (BOE/d)	**962,742**	1,050,702	852,170	**1,006,012**	829,733

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, 2018 increased 33% to 824,060 bbl/d from 617,728 bbl/d for the six months ended June 30, 2017. Crude oil and NGLs production for the second quarter of 2018 of 793,899 bbl/d increased 25% from 637,127 bbl/d for the second quarter of 2017, and decreased 7% from 854,558 bbl/d in the first quarter of 2018. The increase in crude oil and NGLs production for the three and six months ended June 30, 2018 from the comparable periods in 2017 was primarily due to acquisitions completed in 2017 and the impact of Phase 3 production at Horizon. The decrease in production for the second quarter of 2018 from the first quarter of 2018 primarily reflected planned maintenance activities at Horizon, AOSP and various thermal oil facilities, together with the impact of proactive measures taken to delay completion and ramp up of new wells in thermal and heavy oil.

Second quarter 2018 crude oil and NGLs production was within the Company's previously issued guidance of 773,000 to 821,000 bbl/d. Third quarter 2018 crude oil and NGLs production guidance is targeted to average between 771,000 and 819,000 bbl/d.

Natural gas production for the six months ended June 30, 2018 decreased 5% to 1,576 MMcf/d from 1,664 MMcf/d for the six months ended June 30, 2017. Natural gas production for the second quarter of 2018 averaged 1,539 MMcf/d, a decrease of 7% from 1,656 MMcf/d for the second quarter of 2017, and a decrease of 5% from 1,614 MMcf/d for the first quarter of 2018. As a result of low natural gas prices, the Company shut in 27 MMcf/d of production in the second quarter of 2018. Natural gas production continued to reflect processing constraints at a third party facility, where the Company averaged less than 80 MMcf/d for the second quarter of 2018. Subject to regulatory approval, the Company targets to take over operations at the facility in the latter half of 2018 and is evaluating the reinstatement of the facility's processing capacity.

Second quarter 2018 natural gas production was within the Company's previously issued guidance of 1,515 to 1,565 MMcf/d. Third quarter 2018 natural gas production guidance is targeted to average between 1,535 and 1,565 MMcf/d. Annual 2018 natural gas production guidance is now targeted to average between 1,550 and 1,600 MMcf/d.

North America - Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2018 averaged 350,460 bbl/d, comparable with 346,308 bbl/d for the six months ended June 30, 2017. North America crude oil and NGLs production for the second quarter of 2018 increased 3% to 343,538 bbl/d from 332,802 bbl/d for the second quarter of 2017, and decreased 4% from 357,460 bbl/d for the first quarter of 2018. The increase in crude oil and NGLs production for the second quarter of 2018 from the second quarter of 2017 was due to acquisitions completed in 2017. The decrease in production for the second quarter of 2018 from the first quarter of 2018 primarily reflected the curtailment of 7,450 bbl/d during the second quarter as a result of widening differentials as well as planned maintenance activities at various thermal oil facilities, together with the impact of proactive measures taken to delay completion and ramp up of new wells in thermal and heavy oil.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong following the acquisition completed in 2017, leading to production of 63,914 bbl/d in the second quarter of 2018 compared with 46,932 bbl/d in the second quarter of 2017 and 63,274 bbl/d in the first quarter of 2018.

Overall thermal oil production for the second quarter of 2018 averaged 104,907 bbl/d compared with 105,719 bbl/d for the second quarter of 2017 and 111,851 bbl/d for the first quarter of 2018. Second quarter 2018 thermal oil production was within the Company's previously issued guidance of 103,000 to 109,000 bbl/d. Third quarter 2018 thermal oil production guidance is targeted to average between 106,000 and 112,000 bbl/d.

Second quarter 2018 crude oil and NGLs production, including thermal oil, was within the Company's previously issued guidance of 339,000 to 353,000 bbl/d. Third quarter 2018 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 354,000 and 368,000 bbl/d.

Natural gas production for the six months ended June 30, 2018 decreased 6% to 1,515 MMcf/d from 1,607 MMcf/d for the six months ended June 30, 2017. Natural gas production for the second quarter of 2018 averaged 1,485 MMcf/d, a decrease of 7% from 1,603 MMcf/d for the second quarter of 2017, and a decrease of 4% from 1,547 MMcf/d in the first quarter of 2018. As a result of low natural gas prices, the Company shut in 27 MMcf/d of production in the second quarter of 2018. Natural gas production continued to reflect processing constraints at a third party facility, where the Company averaged less than 80 MMcf/d for the second quarter of 2018.

North America – Oil Sands Mining and Upgrading

SCO production for the six months ended June 30, 2018 of 431,756 bbl/d increased 92% from 225,196 bbl/d for the six months ended June 30, 2017. SCO production for the second quarter of 2018 increased 58% to average 407,704 bbl/d from 257,541 bbl/d for the second quarter of 2017 and decreased 11% from 456,076 bbl/d for the first quarter of 2018. The increase in production for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected production from the acquisition of AOSP and the impact of Phase 3 production at Horizon. As expected, production decreased for the second quarter of 2018 from the first quarter of 2018, primarily reflecting planned maintenance activities at Horizon and AOSP.

Second quarter 2018 SCO production was within the Company's previously issued guidance of 393,000 to 423,000 bbl/d. Third quarter 2018 SCO production guidance is targeted to average between 374,000 and 404,000 bbl/d, reflecting the impact of a planned turnaround at Horizon.

North Sea

North Sea crude oil production for the six months ended June 30, 2018 decreased 7% to 23,028 bbl/d from 24,682 bbl/d for the six months ended June 30, 2017. North Sea crude oil production for the second quarter of 2018 decreased 7% to 24,456 bbl/d from 26,304 bbl/d for the second quarter of 2017 and increased 13% from 21,584 bbl/d in the first quarter of 2018. The decrease in production for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected the impact of the shut-in of the Ninian North platform in May 2017 and natural field declines, partially offset by new wells at Tiffany and Ninian. The increase in production for the second quarter of 2018 from the first quarter of 2018 was primarily due to new wells at Tiffany and Ninian.

Offshore Africa

Offshore Africa crude oil production for the six months ended June 30, 2018 decreased 13% to 18,816 bbl/d from 21,542 bbl/d for the six months ended June 30, 2017. Offshore Africa crude oil production for the second quarter of 2018 decreased 11% to 18,201 bbl/d from 20,480 bbl/d for the second quarter of 2017 and decreased 6% from 19,438 bbl/d in the first quarter of 2018. The decrease in production for the three and six months ended June 30, 2018 from the comparable periods primarily reflected planned maintenance activities completed during the second quarter of 2018, as well as natural field declines.

International Guidance

Second quarter 2018 International crude oil production of 42,657 bbl/d was within the Company's previously issued guidance of 41,000 to 45,000 bbl/d. Third quarter 2018 International crude oil production guidance is targeted to average between 43,000 and 47,000 bbl/d.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers 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 2018**	Mar 31 2018	Jun 30 2017
North Sea	**297,217**	506,589	528,705
Offshore Africa	**1,466,074**	1,141,282	1,510,446
	1,763,291	1,647,871	2,039,151

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 61.14**	$ 43.06	$ 47.12	**$ 52.32**	$ 47.08
Transportation	**3.30**	3.10	3.06	**3.20**	2.78
Realized sales price, net of transportation	**57.84**	39.96	44.06	**49.12**	44.30
Royalties	**7.56**	4.87	4.83	**6.25**	4.86
Production expense	**15.64**	15.70	15.51	**15.67**	14.92
Netback	**$ 34.64**	$ 19.39	$ 23.72	**$ 27.20**	$ 24.52
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 1.95**	$ 2.74	$ 2.97	**$ 2.35**	$ 3.11
Transportation	**0.51**	0.51	0.34	**0.50**	0.39
Realized sales price, net of transportation	**1.44**	2.23	2.63	**1.85**	2.72
Royalties	**0.08**	0.10	0.12	**0.09**	0.15
Production expense	**1.39**	1.41	1.25	**1.40**	1.26
Netback (3)	**$ (0.03)**	$ 0.72	$ 1.26	**$ 0.36**	$ 1.31
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 41.63**	$ 32.02	$ 33.94	**$ 36.86**	$ 34.99
Transportation	**3.20**	3.05	2.67	**3.13**	2.62
Realized sales price, net of transportation	**38.43**	28.97	31.27	**33.73**	32.37
Royalties	**4.75**	3.10	3.09	**3.93**	3.24
Production expense	**12.75**	12.68	12.11	**12.71**	11.89
Netback	**$ 20.93**	$ 13.19	$ 16.07	**$ 17.09**	$ 17.24

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

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

(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for the three months ended June 30, 2018 was $0.60/Mcfe (three months ended March 31, 2018 - $1.19/Mcfe, three months ended June 30, 2017 - $1.49/Mcfe).

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 56.95**	$ 40.66	$ 44.78	**$ 48.82**	$ 44.47
North Sea	**$ 93.49**	$ 79.35	$ 64.37	**$ 88.36**	$ 67.49
Offshore Africa	**$ 102.57**	$ 78.85	$ 69.93	**$ 94.17**	$ 65.25
Company average	**$ 61.14**	$ 43.06	$ 47.12	**$ 52.32**	$ 47.08
Natural gas ($/Mcf) (1) (2)					
North America	**$ 1.69**	$ 2.44	$ 2.84	**$ 2.07**	$ 2.96
North Sea	**$ 10.32**	$ 11.67	$ 6.89	**$ 11.06**	$ 7.78
Offshore Africa	**$ 7.37**	$ 6.95	$ 6.84	**$ 7.14**	$ 6.49
Company average	**$ 1.95**	$ 2.74	$ 2.97	**$ 2.35**	$ 3.11
Company average ($/BOE) (1) (2)	**$ 41.63**	$ 32.02	$ 33.94	**$ 36.86**	$ 34.99

(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 10% to $48.82 per bbl for the six months ended June 30, 2018 from $44.47 per bbl for the six months ended June 30, 2017. North America realized crude oil prices averaged $56.95 per bbl for the second quarter of 2018, an increase of 27% compared with $44.78 per bbl for the second quarter of 2017, and an increase of 40% compared with $40.66 per bbl for the first quarter of 2018. The increase in realized crude oil prices for the three and six months ended June 30, 2018 from the comparable periods was primarily due to higher WTI benchmark pricing, partially offset by the widening of the WCS heavy differential. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2018 contributed approximately 183,100 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 30% to average $2.07 per Mcf for the six months ended June 30, 2018 from $2.96 per Mcf for the six months ended June 30, 2017. North America realized natural gas prices decreased 40% to average $1.69 per Mcf for the second quarter of 2018 compared with $2.84 per Mcf for the second quarter of 2017, and decreased 31% compared with $2.44 per Mcf for the first quarter of 2018. The decrease in realized natural gas prices for the three and six months ended June 30, 2018 from the comparable periods primarily reflected third party pipeline constraints limiting flow of natural gas to export markets.

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

(Quarterly Average)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 62.06**	$ 53.48	$ 46.44
Pelican Lake heavy crude oil ($/bbl)	**$ 60.49**	$ 41.63	$ 47.64
Primary heavy crude oil ($/bbl)	**$ 56.33**	$ 36.85	$ 45.92
Bitumen (thermal oil) ($/bbl)	**$ 51.04**	$ 32.22	$ 41.15
Natural gas ($/Mcf)	**$ 1.69**	$ 2.44	$ 2.84

(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 increased 31% to average $88.36 per bbl for the six months ended June 30, 2018 from $67.49 per bbl for the six months ended June 30, 2017. North Sea realized crude oil prices increased 45% to average $93.49 per bbl for the second quarter of 2018 from $64.37 per bbl for the second quarter of 2017 and increased 18% from $79.35 per bbl for the first quarter of 2018. 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, 2018 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 increased 44% to average $94.17 per bbl for the six months ended June 30, 2018 from $65.25 per bbl for the six months ended June 30, 2017. Offshore Africa realized crude oil prices increased 47% to average $102.57 per bbl for the second quarter of 2018 from $69.93 per bbl for the second quarter of 2017 and increased 30% from $78.85 per bbl for the first quarter of 2018. Realized crude oil prices per bbl in any particular year 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, 2018 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 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 8.03**	$ 5.11	$ 5.19	**$ 6.57**	$ 5.32
North Sea	**$ 0.17**	$ 0.23	$ 0.14	**$ 0.19**	$ 0.13
Offshore Africa	**$ 9.58**	$ 3.19	$ 4.26	**$ 7.32**	$ 3.23
Company average	**$ 7.56**	$ 4.87	$ 4.83	**$ 6.25**	$ 4.86
Natural gas ($/Mcf) (1)					
North America	**$ 0.06**	$ 0.09	$ 0.12	**$ 0.08**	$ 0.15
Offshore Africa	**$ 1.17**	$ 0.87	$ 0.51	**$ 1.00**	$ 0.58
Company average	**$ 0.08**	$ 0.10	$ 0.12	**$ 0.09**	$ 0.15
Company average ($/BOE) (1)	**$ 4.75**	$ 3.10	$ 3.09	**$ 3.93**	$ 3.24

(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, 2018 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential.

Crude oil and NGLs royalties averaged approximately 14% of product sales for the six months ended June 30, 2018 compared with 13% of product sales for the six months ended June 30, 2017. Crude oil and NGLs royalties averaged approximately 15% of product sales for the second quarter of 2018 compared with 13% for the second quarter of 2017 and 14% for the first quarter of 2018. The increase in royalties for the three and six months ended June 30, 2018 from the comparable periods was primarily due to higher realized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 12.5% to 14.5% of product sales for 2018.

Natural gas royalties averaged approximately 5% of product sales for the six months ended June 30, 2018 compared with 6% of product sales for the six months ended June 30, 2017. Natural gas royalties averaged approximately 5% of product sales for the second quarter of 2018 compared with 5% for the second quarter of 2017 and 5% for the first quarter of 2018. The decrease in natural gas royalties for the six months ended June 30, 2018 from the six months ended June 30, 2017 primarily reflected lower realized natural gas prices. North America natural gas royalties are anticipated to average 4% to 6% of product sales for 2018.

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 9% for the six months ended June 30, 2018, compared with 5% of product sales for the six months ended June 30, 2017. Royalty rates as a percentage of product sales averaged approximately 10% for the second quarter of 2018, reflecting a lifting at Espoir, compared with 6% of product sales for the second quarter of 2017 and 6% for the first quarter of 2018. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2018.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2018	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.78**	$ 14.15	$ 13.74	**$ 13.96**	$ 12.96
North Sea	**$ 35.12**	$ 43.39	$ 28.86	**$ 38.12**	$ 33.28
Offshore Africa	**$ 24.78**	$ 30.99	$ 32.39	**$ 26.98**	$ 24.27
Company average	**$ 15.64**	$ 15.70	$ 15.51	**$ 15.67**	$ 14.92
Natural gas ($/Mcf) (1)					
North America	**$ 1.28**	$ 1.31	$ 1.17	**$ 1.29**	$ 1.19
North Sea	**$ 5.81**	$ 4.67	$ 3.40	**$ 5.18**	$ 3.23
Offshore Africa	**$ 3.00**	$ 2.44	$ 3.88	**$ 2.69**	$ 3.66
Company average	**$ 1.39**	$ 1.41	$ 1.25	**$ 1.40**	$ 1.26
Company average ($/BOE) (1)	**$ 12.75**	$ 12.68	$ 12.11	**$ 12.71**	$ 11.89

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

North America

North America crude oil and NGLs production expense for the six months ended June 30, 2018 increased 8% to $13.96 per bbl from $12.96 per bbl for the six months ended June 30, 2017. North America crude oil and NGLs production expense for the second quarter of 2018 of $13.78 per bbl was comparable with $13.74 per bbl in the second quarter of 2017 and decreased 3% from $14.15 per bbl for the first quarter of 2018, reflecting the Company's focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in crude oil and NGLs production expense per barrel for the six months ended June 30, 2018 from the six months ended June 30, 2017 primarily reflected increased energy and carbon tax costs along with the impact of proactive measures taken to delay completion and ramp up of new wells in thermal and heavy oil, resulting in lower production volumes in these areas relative to mainly fixed expenses. The decrease per barrel for the second quarter of 2018 from the first quarter of 2018 reflected lower fuel and other service costs in the Company's thermal areas notwithstanding lower volumes on a relatively fixed cost base and increased carbon tax costs. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2018.

North America natural gas production expense for the six months ended June 30, 2018 averaged $1.29 per Mcf, an increase of 8% from $1.19 per Mcf for the six months ended June 30, 2017. North America natural gas production expense for the second quarter of 2018 increased 9% to $1.28 per Mcf from $1.17 per Mcf for the second quarter of 2017 and decreased 2% from $1.31 per Mcf for the first quarter of 2018. The increase in natural gas production expense for the three and six months ended June 30, 2018 from the comparable periods in 2017 reflected the impact of lower volumes on a relatively fixed cost base as a result of proactive measures taken to shut in natural gas production due to low natural gas pricing and address processing reliability issues. The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. North America natural gas production expense is now anticipated to average $1.20 to $1.28 per Mcf for 2018.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2018 increased 15% to $38.12 per bbl from $33.28 per bbl for the six months ended June 30, 2017. North Sea crude oil production expense for the second quarter of 2018 increased 22% to $35.12 per bbl from $28.86 per bbl for the second quarter of 2017 and decreased 19% from $43.39 per bbl in the first quarter of 2018. The increase in crude oil production expense for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected recoveries realized in the second quarter of 2017, as well as the impact of lower volumes on a relatively fixed cost base. The decrease in production expense for the second quarter of 2018 from the first quarter of 2018 primarily reflected the impact of higher volumes on a relatively fixed cost base and the timing of liftings from various fields that have different cost structures, partially offset by higher fuel costs. Production expense is also impacted by fluctuations in the Canadian dollar. North Sea crude oil production expense is anticipated to average $36.00 to $39.00 per bbl for 2018.

Offshore Africa

Crude oil production expense for the Baobab and Espoir fields in Côte d'Ivoire for the six months ended June 30, 2018 was $14.17 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $26.98 per bbl. Production expense for the second quarter of 2018 relating to Côte d'Ivoire was $16.39 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $24.78 per bbl. Total Offshore Africa crude oil production expense for the three and six months ended June 30, 2018 primarily reflected the timing of liftings from various fields, including the Olowi field, that have different cost structures, fluctuating production volumes on a relatively fixed cost base, planned maintenance activities, and fluctuations in the Canadian dollar. On a standalone basis, Offshore Africa production expense related to Côte d'Ivoire is anticipated to average $11.00 to $13.00 per bbl for 2018.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 894**	$ 850	$ 971	**$ 1,744**	$ 2,073
$/BOE (1)	**$ 15.20**	$ 14.66	$ 16.38	**$ 14.93**	$ 17.05

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

Depletion, depreciation and amortization per BOE for the six months ended June 30, 2018 decreased 12% to $14.93 per BOE from $17.05 per BOE for the six months ended June 30, 2017. Depletion, depreciation and amortization expense per BOE for the second quarter of 2018 decreased 7% to $15.20 per BOE from $16.38 per BOE for the second quarter of 2017 and increased 4% from $14.66 per BOE for the first quarter of 2018.

The decrease in depletion, depreciation and amortization expense per BOE for the three and six months ended June 30, 2018 from the comparable periods in 2017 was primarily due to additional depletion, depreciation and amortization expense in 2017 related to the abandonment of the Ninian North platform in the North Sea. The increase for the second quarter of 2018 from the first quarter of 2018 reflected increased sales volumes in the International segments, which have higher associated depletion rates.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 32**	$ 31	$ 29	**$ 63**	$ 57
$/BOE [1]	**$ 0.53**	$ 0.53	$ 0.48	**$ 0.53**	$ 0.47

(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 for the six months ended June 30, 2018 increased 13% to $0.53 per BOE from $0.47 per BOE for the six months ended June 30, 2017. Asset retirement obligation accretion expense for the second quarter of 2018 increased 10% to $0.53 per BOE from $0.48 per BOE for the second quarter of 2017, and was comparable with $0.53 per BOE for the first quarter of 2018.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on reliable and efficient operations. The Oil Sands Mining and Upgrading segment achieved production averaging 407,704 bbl/d during the second quarter of 2018, reflecting planned maintenance activities and pitstops during the quarter. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, cash production costs averaged $22.94 per bbl during the quarter.

Oil Sands operations continued to be strong following the planned maintenance activities at Horizon and AOSP during the second quarter of 2018. Turnaround activities planned for the third quarter of 2018 at Horizon have been reflected in third quarter guidance.

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

	Three Months Ended			Six Months Ended	
($/bbl) [1]	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
SCO realized sales price [2]	**$ 80.17**	$ 71.61	$ 63.39	**$ 75.70**	$ 65.25
Bitumen value for royalty purposes [3]	**$ 49.10**	$ 31.48	$ 39.99	**$ 39.94**	$ 38.37
Bitumen royalties [4]	**$ 4.25**	$ 1.98	$ 1.38	**$ 3.06**	$ 1.28
Transportation	**$ 1.63**	$ 1.54	$ 1.32	**$ 1.59**	$ 1.26

(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 $75.70 per bbl for the six months ended June 30, 2018, an increase of 16% from $65.25 per bbl for the six months ended June 30, 2017. For the second quarter of 2018, the realized sales price increased 26% to $80.17 per bbl from $63.39 per bbl for the second quarter of 2017 and increased 12% from $71.61 per bbl for the first quarter of 2018. The increase in realized sales prices for the three and six months ended June 30, 2018 from the comparable periods primarily reflected WTI benchmark pricing.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Cash production costs, excluding natural gas costs	**$ 834**	$ 835	$ 515	**$ 1,669**	$ 854
Natural gas costs	**21**	38	38	**59**	71
Cash production costs	**$ 855**	$ 873	$ 553	**$ 1,728**	$ 925

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Cash production costs, excluding natural gas costs	**$ 22.37**	$ 20.45	$ 21.85	**$ 21.36**	$ 21.12
Natural gas costs	**0.57**	0.92	1.59	**0.76**	1.75
Cash production costs	**$ 22.94**	$ 21.37	$ 23.44	**$ 22.12**	$ 22.87
Sales (bbl/d)	**409,603**	453,850	259,033	**431,604**	223,353

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

Cash production costs for the six months ended June 30, 2018 decreased 3% to $22.12 per bbl from $22.87 per bbl for the six months ended June 30, 2017. Cash production costs for the second quarter of 2018 averaged $22.94 per bbl, a decrease of 2% from $23.44 per bbl for the second quarter of 2017 and an increase of 7% from $21.37 per bbl for the first quarter of 2018. The decrease in cash production costs per barrel for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, as well as additional capacity from Phase 3 production at Horizon and the acquisition of AOSP. The increase for the second quarter of 2018 from the first quarter of 2018 primarily reflected lower production volumes due to planned maintenance activities at Horizon and AOSP.

For 2018, Oil Sands Mining and Upgrading cash production costs, including turnaround costs, are anticipated to average $20.50 to $24.50 per bbl.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 372**	$ 404	$ 237	**$ 776**	$ 432
$/bbl (1)	**$ 9.99**	$ 9.88	$ 10.05	**$ 9.93**	$ 10.69

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

Depletion, depreciation and amortization expense per barrel for the Oil Sands Mining and Upgrading segment for the six months ended June 30, 2018 decreased 7% to $9.93 per bbl from $10.69 per bbl for the six months ended June 30, 2017. Depletion, depreciation and amortization expense per barrel for the second quarter of 2018 of $9.99 per bbl was comparable with $10.05 per bbl for the second quarter of 2017 and $9.88 per bbl for the first quarter of 2018.

The decrease in depletion, depreciation and amortization expense per barrel for the six months ended June 30, 2018 from the six months ended June 30, 2017 was primarily due to the impact of AOSP, which has a lower depletion rate.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 15**	$ 15	$ 10	**$ 30**	$ 18
$/bbl [1]	**$ 0.41**	$ 0.38	$ 0.42	**$ 0.39**	$ 0.44

(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, 2018 decreased 11% to $0.39 per bbl from $0.44 per bbl for the six months ended June 30, 2017 due to higher sales volumes. Asset retirement obligation accretion expense of $0.41 per bbl for the second quarter of 2018 decreased 2% from $0.42 per bbl for the second quarter of 2017 and increased 8% from $0.38 per bbl for the first quarter of 2018, primarily due to lower sales volumes in the second quarter of 2018 compared to the first quarter of 2018.

MIDSTREAM

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Revenue	**$ 25**	$ 27	$ 23	**$ 52**	$ 48
Production expense	**6**	5	4	**11**	8
Midstream cash flow	**19**	22	19	**41**	40
Depreciation	**4**	3	2	**7**	4
Equity loss (gain) on investment	**2**	1	(10)	**3**	(12)
Segment earnings before taxes	**$ 13**	$ 18	$ 27	**$ 31**	$ 48

The Company has a 50% interest in the Redwater Partnership. 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.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million with project completion targeted for the fourth quarter of 2018. Productivity challenges during construction have continued to result in upward budgetary pressures. 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, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $124 million, for a Company total of $563 million. Any additional subordinated debt financing is not expected to be significant.

As per 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. The Company is unconditionally obligated to pay the service toll of the syndicated credit facility and bonds over the tolling period of 30 years.

As at June 30, 2018, Redwater Partnership had additional borrowings of $2,366 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense	**$ 76**	$ 81	$ 75	**$ 157**	$ 162
$/BOE (1)	**$ 0.79**	$ 0.82	$ 0.90	**$ 0.81**	$ 1.00

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

Administration expense per BOE for the six months ended June 30, 2018 decreased 19% to $0.81 per BOE from $1.00 per BOE for the six months ended June 30, 2017. Administration expense for the second quarter of 2018 of $0.79 per BOE decreased 12% from $0.90 per BOE for the second quarter of 2017 and decreased 4% from $0.82 per BOE for the first quarter of 2018. Administration expense per BOE decreased for the three and six months ended June 30, 2018 from the comparable periods in 2017 primarily due to higher sales volumes. The decrease in the second quarter of 2018 from the first quarter of 2018 was primarily due to higher overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense (recovery)	**$ 175**	$ (88)	$ (104)	**$ 87**	$ (77)

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 an $87 million share-based compensation expense for the six months ended June 30, 2018, primarily as a result of remeasurement 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 share-based compensation expense for the six months ended June 30, 2018 was $6 million related to performance share units granted to certain executive employees (June 30, 2017 – $1 million). For the six months ended June 30, 2018, the Company charged $9 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (June 30, 2017 – $18 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts and interest rates)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Expense, gross	**$ 207**	$ 205	$ 166	**$ 412**	$ 322
Less: capitalized interest	**17**	15	21	**32**	43
Expense, net	**$ 190**	$ 190	$ 145	**$ 380**	$ 279
$/BOE (1)	**$ 1.99**	$ 1.92	$ 1.74	**$ 1.95**	$ 1.72
Average effective interest rate	**3.9%**	3.8%	3.9%	**3.8%**	3.9%

(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, 2018 increased from the comparable periods in 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. Capitalized interest of $32 million for the six months ended June 30, 2018 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, 2018 increased 13% to $1.95 per BOE from $1.72 per BOE for the six months ended June 30, 2017. Net interest and other financing expense per BOE for the second quarter of 2018 increased 14% to $1.99 per BOE from $1.74 per BOE for the second quarter of 2017 and increased 4% from $1.92 per BOE for the first quarter of 2018. The increase for the three and six months ended June 30, 2018 from the comparable periods was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 3. The increase for the second quarter of 2018 from the first quarter of 2018 was primarily due to lower sales volumes.

The Company's average effective interest rate for the three and six months ended June 30, 2018 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 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Crude oil and NGLs financial instruments	**$ —**	$ —	$ (17)	**$ —**	$ (18)
Natural gas financial instruments	**(3)**	—	(1)	**(3)**	(1)
Foreign currency contracts	**(24)**	(19)	5	**(43)**	(6)
Realized gain	**(27)**	(19)	(13)	**(46)**	(25)
Crude oil and NGLs financial instruments	**—**	—	(30)	**—**	(73)
Natural gas financial instruments	**16**	—	(1)	**16**	(9)
Foreign currency contracts	**(24)**	(33)	25	**(57)**	36
Unrealized gain	**(8)**	(33)	(6)	**(41)**	(46)
Net gain	**$ (35)**	$ (52)	$ (19)	**$ (87)**	$ (71)

During the six months ended June 30, 2018, net realized risk management gains were primarily related to the settlement of foreign currency contracts and natural gas AECO swaps. The Company recorded a net unrealized gain of $41 million ($42 million after-tax) on its risk management activities for the six months ended June 30, 2018, including an unrealized gain of $8 million ($11 million after-tax) for the second quarter of 2018 (March 31, 2018 – unrealized gain of $33 million, $31 million after-tax; June 30, 2017 – unrealized gain of $6 million, $2 million loss after-tax).

Further details related to outstanding derivative financial instruments at June 30, 2018 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Net realized (gain) loss	**$ (7)**	$ 116	$ 8	**$ 109**	$ 12
Net unrealized loss (gain)	**178**	162	(355)	**340**	(415)
Net loss (gain) (1)	**$ 171**	$ 278	$ (347)	**$ 449**	$ (403)

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

The net realized foreign exchange loss for the six months ended June 30, 2018 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized foreign exchange loss for the six months ended June 30, 2018 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended June 30, 2018 – unrealized gain of $25 million, March 31, 2018 – unrealized gain of $40 million, June 30, 2017 – unrealized loss of $208 million; six months ended June 30, 2018 – unrealized gain of $65 million, June 30, 2017 – unrealized loss of $231 million). The US/Canadian dollar exchange rate at June 30, 2018 was US$0.7609 (March 31, 2018 – US$0.7751, June 30, 2017 – US $0.7703).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Jun 30 2018**	 Mar 31 2018	 Jun 30 2017	Six Months Ended **Jun 30 2018**	 Jun 30 2017
North America [1]	**$ 247**	$ 150	$ (47)	**$ 397**	$ (9)
North Sea	**7**	1	30	**8**	36
Offshore Africa	**16**	5	7	**21**	14
PRT recovery – North Sea	**(16)**	(4)	(72)	**(20)**	(73)
Other taxes	**3**	2	3	**5**	6
Current income tax expense (recovery)	**257**	154	(79)	**411**	(26)
Deferred corporate income tax expense	**156**	127	110	**283**	138
Deferred PRT expense – North Sea	**7**	10	52	**17**	60
Deferred income tax expense	**163**	137	162	**300**	198
	$ 420	$ 291	$ 83	**$ 711**	$ 172
Effective income tax rate on adjusted net earnings from operations [2]	**23%**	24%	20%	**23%**	20%

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

(2) 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, 2018 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, 2018 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

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 2018, the Company expects to recognize current income tax expenses ranging from $600 million to $700 million in Canada and $nil to $30 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2018	Three Months Ended Mar 31 2018	Three Months Ended Jun 30 2017	Six Months Ended Jun 30 2018	Six Months Ended Jun 30 2017
Exploration and Evaluation					
Net expenditures [2] [3] [4]	**$ 8**	$ 56	$ 30	**$ 64**	$ 67
Property, Plant and Equipment					
Net property acquisitions [2] [3] [4]	**(70)**	162	371	**92**	380
Well drilling, completion and equipping	**350**	321	208	**671**	548
Production and related facilities	**308**	264	194	**572**	361
Capitalized interest and other [5]	**25**	23	21	**48**	42
Net expenditures	**613**	770	794	**1,383**	1,331
Total Exploration and Production	**621**	826	824	**1,447**	1,398
Oil Sands Mining and Upgrading					
Project costs [6]	**63**	66	182	**129**	321
Sustaining capital	**152**	105	85	**257**	152
Turnaround costs	**46**	13	10	**59**	11
Acquisitions of Exploration and Evaluation assets [2] [4]	**—**	—	219	**—**	219
Net property acquisitions [2] [4]	**—**	—	11,604	**—**	11,604
Capitalized interest and other [5]	**30**	(5)	(3)	**25**	17
Total Oil Sands Mining and Upgrading	**291**	179	12,097	**470**	12,324
Midstream	**5**	4	1	**9**	2
Abandonments [7]	**50**	90	105	**140**	146
Head office	**7**	4	19	**11**	22
Total net capital expenditures	**$ 974**	$ 1,103	$ 13,046	**$ 2,077**	$ 13,892
By segment					
North America [2] [3] [4]	**$ 568**	$ 772	$ 765	**$ 1,340**	$ 1,285
North Sea [3]	**3**	35	41	**38**	76
Offshore Africa	**50**	19	18	**69**	37
Oil Sands Mining and Upgrading [4]	**291**	179	12,097	**470**	12,324
Midstream	**5**	4	1	**9**	2
Abandonments [7]	**50**	90	105	**140**	146
Head office	**7**	4	19	**11**	22
Total	**$ 974**	$ 1,103	$ 13,046	**$ 2,077**	$ 13,892

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

(2) Includes business combinations.

(3) Includes proceeds from the acquisition and disposition of properties.

(4) In the second quarter of 2017, total purchase consideration for the acquisition of interests in AOSP of $12,157 million included $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment.

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

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

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

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, 2018 were $2,077 million compared with $13,892 million for the six months ended June 30, 2017. Net capital expenditures for the second quarter of 2018 were $974 million, compared with $13,046 million for the second quarter of 2017 and $1,103 million for the first quarter of 2018. Net capital expenditures for the three and six months ended June 30, 2018 included the acquisition of the remaining interest at the Ninian field in the North Sea for net proceeds received of $73 million. The Company recognized a pre-tax gain of $120 million ($72 million after-tax) on the acquisition and a pre-tax revaluation gain of $19 million ($11 million after-tax) relating to its previously held interest.

Oil Sands Mining and Upgrading

At Horizon, the Phase 2/3 expansion program is essentially complete with residual scope remaining related to Mature Fine Tailings and mine basal water.

Drilling Activity

	Three Months Ended			Six Months Ended	
(number of net wells)	**Jun 30 2018**	Mar 31 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Net successful natural gas wells	**4**	5	5	**9**	16
Net successful crude oil wells (1)	**81**	122	61	**203**	216
Dry wells	**—**	2	2	**2**	3
Stratigraphic test / service wells	**27**	450	6	**477**	232
Total	**112**	579	74	**691**	467
Success rate (excluding stratigraphic test / service wells)	**100%**	98%	97%	**99%**	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 69% of the total net capital expenditures for the six months ended June 30, 2018 compared with approximately 9% for the six months ended June 30, 2017.

During the second quarter of 2018, the Company targeted 4 net natural gas wells in Northeast British Columbia. The Company also targeted 79 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 39 primary heavy crude oil wells, 11 Pelican Lake heavy crude oil wells, 21 bitumen (thermal oil) wells and 4 light crude oil wells were drilled. Another 4 wells targeting light crude oil were drilled outside the Northern Plains region.

North Sea

During the second quarter of 2018, the Company completed two gross production wells (1.9 on a net basis) in the North Sea (six months ended June 30, 2018 – three gross production wells (2.9 on a net basis)). In the third quarter of 2018, the Company is targeting to drill one gross injection well and one gross production well, completing the North Sea drilling program.

Offshore Africa

During the second quarter of 2018, the Company commenced drilling operations at Baobab. The Company is targeting three gross production wells and two gross injection wells for the drilling program.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Jun 30 2018	Mar 31 2018	Dec 31 2017	Jun 30 2017
Working capital (1)	**$ 942**	$ 702	$ 513	$ 876
Long-term debt (2) (3)	**$ 21,397**	$ 21,978	$ 22,458	$ 23,276
Less: cash and cash equivalents	**182**	152	137	50
Long-term debt, net	**$ 21,215**	$ 21,826	$ 22,321	$ 23,226
Share capital	**$ 9,405**	$ 9,264	$ 9,109	$ 8,771
Retained earnings	**22,994**	22,785	22,612	22,203
Accumulated other comprehensive income (loss)	**12**	(23)	(68)	12
Shareholders' equity	**$ 32,411**	$ 32,026	$ 31,653	$ 30,986
Debt to book capitalization (3) (4)	**39.6%**	40.5%	41.4%	42.8%
Debt to market capitalization (3) (5)	**26.7%**	30.5%	28.9%	33.8%
After-tax return on average common shareholders' equity (6)	**8.3%**	8.7%	8.0%	5.7%
After-tax return on average capital employed (3) (7)	**5.9%**	6.0%	5.6%	4.2%

(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 for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

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

At June 30, 2018, the Company’s capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds flow from operations 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, 2017. 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 funds flow from operations 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 funds flow from operations, 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;
- For the six months ended June 30, 2018, the Company utilized funds flow from operations to facilitate net repayment of bank credit facilities and US dollar debt securities of $2,096 million, excluding the impact of foreign exchange on debt balances, including:
  - repayment and cancellation of the $125 million non-revolving credit facility;
  - repayment and cancellation of $150 million of the $3,000 million non-revolving term loan facility; and
  - repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Additionally, the Company utilized available liquidity to settle the deferred payment to Marathon Oil Corporation for $481 million, resulting in total net repayments of debt of $1,615 million.
- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving 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 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility 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, 2018, the $2,200 million facility was fully drawn.
  - Borrowings under the $750 million non-revolving credit facility 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, 2018, the $750 million facility was fully drawn.
  - 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 bank credit facilities for amounts outstanding under this program.
  - In July 2017, 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 expires 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.

At June 30, 2018, the Company had in place revolving bank credit facilities of $4,976 million, of which $4,602 million was available, resulting in liquidity of $4,784 million, including cash and cash equivalents. Additionally, the Company had in place fully drawn term credit facilities of $5,800 million. This excludes certain other dedicated credit facilities supporting letters of credit.

At June 30, 2018, the Company had total US dollar denominated debt with a carrying amount of $14,316 million (US $10,895 million), before transaction costs and original issue discounts. This included $5,641 million (US$4,295 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,245 million). The fixed repayment amount of these hedging instruments is $5,397 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $244 million to $14,072 million as at June 30, 2018.

Net long-term debt was $21,215 million at June 30, 2018, resulting in a debt to book capitalization ratio of 39.6% (December 31, 2017 – 41.4%); 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 funds flow from operations 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, 2018 are discussed in note 9 of the Company's unaudited interim consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At June 30, 2018, 300,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for July 2018 to October 2018. Further details related to the Company's commodity derivative financial instruments outstanding at June 30, 2018 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at June 30, 2018, there were 1,220,871,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 48,462,000 stock options outstanding. As at July 31, 2018, the Company had 1,221,306,000 common shares outstanding and 46,920,000 stock options outstanding.

On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018 (previous quarterly dividend rate of $0.275 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 16, 2018, 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 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

For the six months ended June 30, 2018, the Company purchased for cancellation 10,140,127 common shares at a weighted average price of $43.52 per common share for a total cost of $441 million. Retained earnings were reduced by $363 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2018, the Company purchased 722,600 common shares at a weighted average price of $46.95 per common share for a total cost of $34 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, 2018:

($ millions)	Remaining 2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$ 344	$ 610	$ 561	$ 541	$ 474	$ 3,892
North West Redwater Partnership debt service toll (1)	$ 46	$ 79	$ 126	$ 157	$ 158	$ 3,015
Offshore equipment operating leases	$ 91	$ 94	$ 70	$ 68	$ 7	$ —
Long-term debt (2)	$ 327	$ 1,150	$ 6,843	$ 1,412	$ 1,000	$ 10,796
Interest and other financing expense (3)	$ 419	$ 828	$ 737	$ 596	$ 543	$ 5,629
Office leases	$ 22	$ 42	$ 43	$ 40	$ 31	$ 121
Other	$ 61	$ 44	$ 39	$ 36	$ 39	$ 365

(1) *As per 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 service toll is $1,340 million of interest payable over the 30 year tolling period.*

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

(3) *Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at June 30, 2018.*

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, refer to the audited consolidated financial statements for the year ended December 31, 2017 and the unaudited interim consolidated financial statements for the three and six months ended June 30, 2018.

ACCOUNTING POLICIES ISSUED BUT NOT YET APPLIED

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires the recognition of right-of-use assets and lease liabilities on the balance sheet. An exemption is available for mineral leases and for certain short-term leases and low-value assets, and these leases are not required to be recognized on the balance sheet. The new standard is effective January 1, 2019 and is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is in the process of reviewing its various lease agreements and business processes as a result of the new standard. The adoption of IFRS 16 may have a significant impact on the Company's financial statements.

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 could 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, 2017.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note		**Jun 30 2018**		Dec 31 2017
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**182**	$	137
Accounts receivable			**2,611**		2,397
Current income taxes receivable			**—**		322
Inventory			**1,041**		894
Prepaids and other			**310**		175
Investments	7		**745**		893
Current portion of other long-term assets	8		**85**		79
			4,974		4,897
Exploration and evaluation assets	4		**2,608**		2,632
Property, plant and equipment	5		**64,859**		65,170
Other long-term assets	8		**1,238**		1,168
		$	**73,679**	$	73,867
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**970**	$	775
Accrued liabilities			**2,542**		2,597
Current income taxes payable			**119**		—
Current portion of long-term debt	9		**826**		1,877
Current portion of other long-term liabilities	10		**401**		1,012
			4,858		6,261
Long-term debt	9		**20,571**		20,581
Other long-term liabilities	10		**4,498**		4,397
Deferred income taxes			**11,341**		10,975
			41,268		42,214
SHAREHOLDERS' EQUITY					
Share capital	12		**9,405**		9,109
Retained earnings			**22,994**		22,612
Accumulated other comprehensive income (loss)	13		**12**		(68)
			32,411		31,653
		$	**73,679**	$	73,867

Commitments and contingencies (note 17).

Approved by the Board of Directors on August 1, 2018.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Jun 30 2018	Three Months Ended Jun 30 2017	Six Months Ended Jun 30 2018	Six Months Ended Jun 30 2017
Product sales		**$ 6,389**	$ 4,127	**$ 12,124**	$ 8,119
Less: royalties		**(437)**	(216)	**(698)**	(446)
Revenue		**5,952**	3,911	**11,426**	7,673
Expenses					
Production		**1,622**	1,293	**3,252**	2,414
Transportation, blending and feedstock		**1,142**	762	**2,294**	1,505
Depletion, depreciation and amortization	5	**1,270**	1,210	**2,527**	2,509
Administration		**76**	75	**157**	162
Share-based compensation	10	**175**	(104)	**87**	(77)
Asset retirement obligation accretion	10	**47**	39	**93**	75
Interest and other financing expense		**190**	145	**380**	279
Risk management activities	16	**(35)**	(19)	**(87)**	(71)
Foreign exchange loss (gain)		**171**	(347)	**449**	(403)
Gain on acquisition, disposition and revaluation of properties	4, 5, 6	**(139)**	(265)	**(139)**	(265)
Loss (gain) from investments	7, 8	**31**	(33)	**137**	56
		4,550	2,756	**9,150**	6,184
Earnings before taxes		**1,402**	1,155	**2,276**	1,489
Current income tax expense (recovery)	11	**257**	(79)	**411**	(26)
Deferred income tax expense	11	**163**	162	**300**	198
Net earnings		**$ 982**	$ 1,072	**$ 1,565**	$ 1,317
Net earnings per common share					
Basic	15	**$ 0.80**	$ 0.93	**$ 1.28**	$ 1.16
Diluted	15	**$ 0.80**	$ 0.93	**$ 1.27**	$ 1.16

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2018	Three Months Ended Jun 30 2017	Six Months Ended Jun 30 2018	Six Months Ended Jun 30 2017
Net earnings	**$ 982**	$ 1,072	**$ 1,565**	$ 1,317
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 $nil (2017 – $6 million) – three months ended; $2 million (2017 – $6 million) – six months ended	**1**	40	**(15)**	39
Reclassification to net earnings, net of taxes of $1 million (2017 – $2 million) – three months ended; $3 million (2017 – $3 million) – six months ended	**(12)**	(15)	**(22)**	(22)
	(11)	25	**(37)**	17
Foreign currency translation adjustment				
Translation of net investment	**46**	(56)	**117**	(75)
Other comprehensive income (loss), net of taxes	**35**	(31)	**80**	(58)
Comprehensive income	**$ 1,017**	$ 1,041	**$ 1,645**	$ 1,259

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended **Jun 30 2018**	Jun 30 2017
Share capital	12		
Balance – beginning of period		**$ 9,109**	$ 4,671
Issued for the acquisition of AOSP and other assets [(1)]	6	**—**	3,818
Issued upon exercise of stock options		**273**	224
Previously recognized liability on stock options exercised for common shares		**101**	58
Purchase of common shares under Normal Course Issuer Bid		**(78)**	–
Balance – end of period		**9,405**	8,771
Retained earnings			
Balance – beginning of period		**22,612**	21,526
Net earnings		**1,565**	1,317
Purchase of common shares under Normal Course Issuer Bid	12	**(363)**	—
Dividends on common shares	12	**(820)**	(640)
Balance – end of period		**22,994**	22,203
Accumulated other comprehensive income	13		
Balance – beginning of period		**(68)**	70
Other comprehensive income (loss), net of taxes		**80**	(58)
Balance – end of period		**12**	12
Shareholders' equity		**$ 32,411**	$ 30,986

(1) In connection with the acquisition of direct and indirect interests in the Athabasca Oil Sands Project ("AOSP") and other assets, the Company issued non-cash share consideration of $3,818 million in the second quarter of 2017. See note 6.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Jun 30 2018	Three Months Ended Jun 30 2017	Six Months Ended Jun 30 2018	Six Months Ended Jun 30 2017
Operating activities					
Net earnings		**$ 982**	$ 1,072	**$ 1,565**	$ 1,317
Non-cash items					
Depletion, depreciation and amortization		**1,270**	1,210	**2,527**	2,509
Share-based compensation		**175**	(104)	**87**	(77)
Asset retirement obligation accretion		**47**	39	**93**	75
Unrealized risk management gain		**(8)**	(6)	**(41)**	(46)
Unrealized foreign exchange loss (gain)		**178**	(355)	**340**	(415)
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**146**	—
Loss (gain) from investments	7, 8	**38**	(27)	**151**	69
Deferred income tax expense		**163**	162	**300**	198
Gain on acquisition, disposition and revaluation of properties	4, 5, 6	**(139)**	(265)	**(139)**	(265)
Other		**14**	(29)	**15**	(7)
Abandonment expenditures		**(50)**	(105)	**(140)**	(146)
Net change in non-cash working capital		**(57)**	39	**178**	90
		2,613	1,631	**5,082**	3,302
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	9	**(760)**	3,062	**(379)**	2,634
Issue of medium-term notes, net	9	**—**	1,791	**—**	1,791
(Repayment) issue of US dollar debt securities, net	9	**—**	2,733	**(1,236)**	2,733
Issue of common shares on exercise of stock options		**167**	64	**273**	224
Purchase of common shares under Normal Course Issuer Bid		**(441)**	—	**(441)**	—
Dividends on common shares		**(411)**	(306)	**(747)**	(583)
		(1,445)	7,344	**(2,530)**	6,799
Investing activities					
Net expenditures on exploration and evaluation assets		**(8)**	(4)	**(64)**	(41)
Net expenditures on property, plant and equipment		**(916)**	(780)	**(1,873)**	(1,548)
Acquisition of AOSP and other assets, net of cash acquired [(1)]	6	**—**	(8,630)	**—**	(8,630)
Investment in other long-term assets		**(7)**	(23)	**(28)**	(23)
Net change in non-cash working capital		**(207)**	493	**(542)**	174
		(1,138)	(8,944)	**(2,507)**	(10,068)
Increase in cash and cash equivalents		**30**	31	**45**	33
Cash and cash equivalents – beginning of period		**152**	19	**137**	17
Cash and cash equivalents – end of period		**$ 182**	$ 50	**$ 182**	$ 50
Interest paid, net		**$ 223**	$ 123	**$ 483**	$ 322
Income taxes received		**$ (14)**	$ (260)	**$ (77)**	$ (325)

(1) The acquisition of AOSP in the second quarter of 2017 includes net working capital of $291 million and excludes non-cash share consideration of $3,818 million. See note 6.

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, Gabon, 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, the Company maintains certain midstream 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 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, 2017, 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, 2017.

2. CHANGES IN ACCOUNTING POLICIES

IFRS 15 "Revenue from Contracts with Customers"

In May 2014, the IASB issued IFRS 15 “Revenue from Contracts with Customers” to provide guidance on the recognition of revenue and cash flows arising from an entity’s contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements.

The Company adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15. Under the standard, the Company is required to provide additional disclosure of disaggregated revenue by major product type. In connection with adoption of the standard, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted this period.

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated. Applying this expedient had no impact to the revenue recognized under the previous revenue accounting standard as all performance obligations had been met and the consideration had been determined.

Effective January 1, 2018, the Company’s accounting policy for Revenue is as follows:

Revenue from the sale of crude oil and NGLs and natural gas products is recognized when control of the product passes to the customer and it is probable that the Company will collect the consideration to which it is entitled. Control generally passes to the customer at the point in time when the product is delivered to a location specified in a contract. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Contracts for sale of the Company’s products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.

Sales of the Company’s crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statement of earnings represents the Company’s share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 18.

IFRS 9 "Financial Instruments"

Effective January 1, 2014, the Company adopted the version of IFRS 9 “Financial Instruments” issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model.

The Company retrospectively adopted the amendment to IFRS 9 on January 1, 2018 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Accordingly, provisions for impairment have not been restated in the comparative periods. Adoption of the amendment did not have a significant impact on the Company’s previous accounting for impairment of financial assets.

Effective January 1, 2018, the Company’s accounting policy for impairment of financial assets is as follows:

At each reporting date, on a forward looking basis, the Company assesses the expected credit losses associated with its debt instruments carried at amortized cost. For trade accounts receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime losses to be recognized from initial recognition of the receivables. Credit risk is assessed based on the number of days the receivable has been outstanding and an internal credit assessment of the customer. Credit risk for longer-term receivables is assessed based on an internal credit assessment and where available, an external credit rating of the counterparty.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires the recognition of right-of-use assets and lease liabilities on the balance sheet. An exemption is available for mineral leases and for certain short-term leases and low-value assets, and these leases are not required to be recognized on the balance sheet. The new standard is effective January 1, 2019 and is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is in the process of reviewing its various lease agreements and business processes as a result of the new standard. The adoption of IFRS 16 may have a significant impact on the Company's financial statements.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2017	$ 2,282	$ —	$ 91	$ 259	$ 2,632
Additions	**57**	**—**	**7**	**—**	**64**
Transfers to property, plant and equipment	**(81)**	**—**	**—**	**—**	**(81)**
Disposals/derecognitions and other	**—**	**—**	**—**	**(7)**	**(7)**
At June 30, 2018	**$ 2,258**	**$ —**	**$ 98**	**$ 252**	**$ 2,608**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2017	$ 64,816	$ 7,126	$ 4,881	$ 42,084	$ 428	$ 414	$ 119,749
Additions	**1,285**	**252**	**62**	**419**	**9**	**11**	**2,038**
Transfers from E&E assets	**81**	**—**	**—**	**—**	**—**	**—**	**81**
Disposals/derecognitions and other	**(184)**	**—**	**—**	**(60)**	**—**	**—**	**(244)**
Foreign exchange adjustments and other	**—**	**360**	**246**	**—**	**—**	**—**	**606**
At June 30, 2018	**$ 65,998**	**$ 7,738**	**$ 5,189**	**$ 42,443**	**$ 437**	**$ 425**	**$ 122,230**
Accumulated depletion and depreciation							
At December 31, 2017	$ 41,151	$ 5,653	$ 3,719	$ 3,628	$ 124	$ 304	$ 54,579
Expense	**1,547**	**116**	**70**	**776**	**7**	**11**	**2,527**
Disposals/derecognitions	**(184)**	**—**	**—**	**(60)**	**—**	**—**	**(244)**
Foreign exchange adjustments and other	**—**	**295**	**219**	**(5)**	**—**	**—**	**509**
At June 30, 2018	**$ 42,514**	**$ 6,064**	**$ 4,008**	**$ 4,339**	**$ 131**	**$ 315**	**$ 57,371**
Net book value							
- at June 30, 2018	**$ 23,484**	**$ 1,674**	**$ 1,181**	**$ 38,104**	**$ 306**	**$ 110**	**$ 64,859**
- at December 31, 2017	$ 23,665	$ 1,473	$ 1,162	$ 38,456	$ 304	$ 110	$ 65,170

Project costs not subject to depletion and depreciation	**Jun 30 2018**	Dec 31 2017
Kirby Thermal Oil Sands – North	**$ 1,163**	$ 944

During the six months ended June 30, 2018, the Company acquired a number of producing crude oil and natural gas properties in the North America and North Sea Exploration and Production segments. These transactions were accounted for using the acquisition method of accounting.

In connection with the acquisitions in North America Exploration and Production, the Company acquired property, plant and equipment for net cash consideration paid of $165 million and assumed associated asset retirement obligations of $11 million. No net deferred income tax liabilities were recognized on these acquisitions.

In connection with the acquisition of the remaining interest in certain operations in the North Sea Exploration and Production segment, the Company acquired $108 million of property, plant and equipment, for net proceeds received of $73 million. The Company also acquired net working capital of $7 million, assumed associated asset retirement obligations of $41 million and recognized net deferred income tax liabilities of $27 million related to temporary differences in the carrying amount of the acquired properties and their tax bases. The Company recognized a pre-tax gain of $120 million ($72 million after-tax) on the acquisition and a pre-tax revaluation gain of $19 million ($11 million after-tax) relating to its previously held interest.

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, 2018, pre-tax interest of $32 million (June 30, 2017 – $43 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.8% (June 30, 2017 – 3.9%).

6. ACQUISITION OF INTERESTS IN THE ATHABASCA OIL SANDS PROJECT AND OTHER ASSETS

On May 31, 2017, the Company completed the acquisition of a direct and indirect 70% interest in AOSP from Shell Canada Limited and certain subsidiaries (“Shell”) and an affiliate of Marathon Oil Corporation (“Marathon"), including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta, 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project, and a 100% working interest in the Peace River thermal in situ operations and Cliffdale heavy oil field, as well as other oil sands leases. The Company also assumed certain pipeline and other commitments. The Company consolidates its direct and indirect interest in the assets, liabilities, revenue and expenses of AOSP and other assets in proportion to the Company’s interests.

Total purchase consideration of $12,541 million was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a fair value of approximately $3,818 million, and deferred purchase consideration of $506 million (US$375 million) paid to Marathon in March 2018. The fair value of the Company's common shares was determined using the market price of the shares as at the acquisition date.

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The fair value of the assets acquired and liabilities assumed was based on management's best estimate as at the acquisition date. The Company recognized a gain of $230 million, net of transaction costs of $3 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration.

7. INVESTMENTS

As at June 30, 2018, the Company had the following investments:

	Jun 30 2018	Dec 31 2017
Investment in PrairieSky Royalty Ltd.	**$ 587**	$ 726
Investment in Inter Pipeline Ltd.	**158**	167
	$ 745	$ 893

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, remeasured at each reporting date. As at June 30, 2018, the Company’s investment in PrairieSky was classified as a current asset.

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

	Three Months Ended		Six Months Ended	
	Jun 30 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Fair value loss (gain) from PrairieSky	**$ 51**	$ (34)	**$ 139**	$ 54
Dividend income from PrairieSky	**(4)**	(4)	**(8)**	(8)
	$ 47	$ (38)	**$ 131**	$ 46

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, remeasured at each reporting date. As at June 30, 2018, the Company's investment in Inter Pipeline was classified as a current asset.

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

	Three Months Ended		Six Months Ended	
	Jun 30 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Fair value (gain) loss from Inter Pipeline	**$ (15)**	$ 17	**$ 9**	$ 27
Dividend income from Inter Pipeline	**(3)**	(2)	**(6)**	(5)
	$ (18)	$ 15	**$ 3**	$ 22

8. OTHER LONG-TERM ASSETS

		Jun 30 2018		Dec 31 2017
Investment in North West Redwater Partnership	$	**289**	$	292
North West Redwater Partnership subordinated debt (1)		**563**		510
Risk management (note 16)		**272**		204
Other		**199**		241
		1,323		1,247
Less: current portion		**85**		79
	$	**1,238**	$	1,168

(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.

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million with project completion targeted for the fourth quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures. 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, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $124 million, for a Company total of $563 million. Any additional subordinated debt financing is not expected to be significant.

As per 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 (see note 17). The Company is unconditionally obligated to pay the service toll of the syndicated credit facility and bonds over the tolling period of 30 years.

As at June 30, 2018, Redwater Partnership had additional borrowings of $2,366 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

During the three months ended June 30, 2018, the Company recognized an equity loss from Redwater Partnership of $2 million (three months ended June 30, 2017 – gain of $10 million; six months ended June 30, 2018 – loss of $3 million; six months ended June 30, 2017 – gain of $12 million).

9. LONG-TERM DEBT

		Jun 30 2018		Dec 31 2017
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**1,912**	$	3,544
Medium-term notes		**5,300**		5,300
		7,212		8,844
US dollar denominated debt, unsecured				
Bank credit facilities (June 30, 2018 - US$2,996 million; December 31, 2017 - US$1,839 million)		**3,936**		2,300
Commercial paper (June 30, 2018 - US$249 million; December 31, 2017 - US$500 million)		**326**		625
US dollar debt securities (June 30, 2018 - US$7,650 million; December 31, 2017 - US$8,650 million)		**10,054**		10,828
		14,316		13,753
Long-term debt before transaction costs and original issue discounts, net		**21,528**		22,597
Less: original issue discounts, net (1)		**18**		18
transaction costs (1) (2)		**113**		121
		21,397		22,458
Less: current portion of commercial paper		**326**		625
current portion of other long-term debt (1) (2)		**500**		1,252
	$	**20,571**	$	20,581

(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, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,602 million was available. Additionally, the Company had in place fully drawn term credit facilities of $5,800 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 $2,850 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 with $330 million maturing in June 2019 and $2,095 million maturing June 2021;
- a $2,425 million revolving syndicated 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 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving 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 first quarter of 2018, the Company repaid and cancelled $150 million of the $3,000 million non-revolving term loan facility, which matures in May 2020. Borrowings under the term loan facility 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, 2018, the $2,850 million facility was fully drawn.

During the second quarter of 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility 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, 2018, the $2,200 million facility was fully drawn.

During the first quarter of 2018, the Company repaid and cancelled the $125 million non-revolving term credit facility scheduled to mature in February 2019. The Company also extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021. Borrowings under the $750 million non-revolving credit facility 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, 2018, the $750 million facility was 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 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, 2018 was 2.4% (June 30, 2017 – 1.9%), and on total long-term debt outstanding for the six months ended June 30, 2018 was 3.8% (June 30, 2017 – 3.9%).

At June 30, 2018, letters of credit and guarantees aggregating to $423 million were outstanding, including a financial guarantee of $39 million related to Oil Sands Mining and Upgrading and letters of credit of $61 million related to North Sea operations.

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, which expires 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

During the first quarter of 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% 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 US $3,000 million of debt securities in the United States, which expires 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.

10. OTHER LONG-TERM LIABILITIES

	Jun 30 2018	Dec 31 2017
Asset retirement obligations	**$ 4,390**	$ 4,327
Share-based compensation	**405**	414
Risk management (note 16)	**16**	103
Other (1)	**88**	565
	4,899	5,409
Less: current portion	**401**	1,012
	$ 4,498	$ 4,397

(1) Included in Other at December 31, 2017 was $469 million (US$375 million) of deferred purchase consideration paid to Marathon in March 2018.

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 have been discounted using a weighted average discount rate of 4.7% (December 31, 2017 – 4.7%). Reconciliations of the discounted asset retirement obligations were as follows:

	Jun 30 2018	Dec 31 2017
Balance – beginning of period	**$ 4,327**	$ 3,243
Liabilities incurred	**9**	12
Liabilities acquired, net	**52**	784
Liabilities settled	**(140)**	(274)
Asset retirement obligation accretion	**93**	164
Revision of cost, inflation rates and timing estimates	**—**	(40)
Change in discount rate	**—**	509
Foreign exchange adjustments	**49**	(71)
Balance – end of period	**4,390**	4,327
Less: current portion	**67**	92
	$ 4,323	$ 4,235

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 2018	Dec 31 2017
Balance – beginning of period	**$ 414**	$ 426
Share-based compensation expense	**87**	134
Cash payment for stock options surrendered	**(4)**	(6)
Transferred to common shares	**(101)**	(154)
Charged to Oil Sands Mining and Upgrading, net	**9**	14
Balance – end of period	**405**	414
Less: current portion	**302**	348
	$ 103	$ 66

Included within share-based compensation expense for the six months ended June 30, 2018 was $6 million related to performance share units granted to certain executive employees (June 30, 2017 - $1 million).

11. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
Expense (recovery)	**Jun 30 2018**	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Current corporate income tax – North America	**$ 247**	$ (47)	**$ 397**	$ (9)
Current corporate income tax – North Sea	**7**	30	**8**	36
Current corporate income tax – Offshore Africa	**16**	7	**21**	14
Current PRT (1) – North Sea	**(16)**	(72)	**(20)**	(73)
Other taxes	**3**	3	**5**	6
Current income tax	**257**	(79)	**411**	(26)
Deferred corporate income tax	**156**	110	**283**	138
Deferred PRT (1) – North Sea	**7**	52	**17**	60
Deferred income tax	**163**	162	**300**	198
Income tax	**$ 420**	$ 83	**$ 711**	$ 172

(1) Petroleum Revenue Tax.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Six Months Ended Jun 30, 2018	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,222,769**	**$ 9,109**
Issued upon exercise of stock options	**8,242**	**273**
Previously recognized liability on stock options exercised for common shares	**—**	**101**
Purchase of common shares under Normal Course Issuer Bid	**(10,140)**	**(78)**
Balance – end of period	**1,220,871**	**$ 9,405**

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 February 28, 2018, the Board of Directors declared a quarterly dividend of $0.335 per common share, an increase from the previous quarterly dividend of $0.275 per common share.

Normal Course Issuer Bid

On May 16, 2018, 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 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

For the six months ended June 30, 2018, the Company purchased 10,140,127 common shares at a weighted average price of $43.52 per common share for a total cost of $441 million. Retained earnings were reduced by $363 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2018, the Company purchased 722,600 common shares at a weighted average price of $46.95 per common share for a total cost of $34 million.

Stock Options

The following table summarizes information relating to stock options outstanding at June 30, 2018:

	Six Months Ended Jun 30, 2018		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**56,036**	**$**	**36.67**
Granted	**3,100**	**$**	**44.57**
Surrendered for cash settlement	**(298)**	**$**	**33.09**
Exercised for common shares	**(8,242)**	**$**	**33.12**
Forfeited	**(2,134)**	**$**	**38.38**
Outstanding – end of period	**48,462**	**$**	**37.73**
Exercisable – end of period	**11,548**	**$**	**35.65**

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.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Jun 30 2018		Jun 30 2017
Derivative financial instruments designated as cash flow hedges	**$**	**10**	$	44
Foreign currency translation adjustment		**2**		(32)
	$	**12**	$	12

14. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. 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, 2018, the ratio was within the target range at 39.6%.

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 2018	Dec 31 2017
Long-term debt, net [(1)]	**$ 21,215**	$ 22,321
Total shareholders' equity	**$ 32,411**	$ 31,653
Debt to book capitalization	**39.6%**	41.4%

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

15. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2018	Jun 30 2017	**Jun 30 2018**	Jun 30 2017
Weighted average common shares outstanding – basic (thousands of shares)	**1,226,021**	1,150,335	**1,225,820**	1,131,740
Effect of dilutive stock options (thousands of shares)	**6,486**	7,845	**6,279**	8,077
Weighted average common shares outstanding – diluted (thousands of shares)	**1,232,507**	1,158,180	**1,232,099**	1,139,817
Net earnings	**$ 982**	$ 1,072	**$ 1,565**	$ 1,317
Net earnings per common share – basic	**$ 0.80**	$ 0.93	**$ 1.28**	$ 1.16
– diluted	**$ 0.80**	$ 0.93	**$ 1.27**	$ 1.16

16. FINANCIAL INSTRUMENTS

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

	Jun 30, 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	**$ 2,611**	**$ —**	**$ —**	**$ —**	**$ 2,611**
Investments	**—**	**745**	**—**	**—**	**745**
Other long-term assets	**563**	**19**	**253**	**—**	**835**
Accounts payable	**—**	**—**	**—**	**(970)**	**(970)**
Accrued liabilities	**—**	**—**	**—**	**(2,542)**	**(2,542)**
Other long-term liabilities	**—**	**(16)**	**—**	**—**	**(16)**
Long-term debt [1]	**—**	**—**	**—**	**(21,397)**	**(21,397)**
	$ 3,174	**$ 748**	**$ 253**	**$ (24,909)**	**$ (20,734)**

	Dec 31, 2017				
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	$ 2,397	$ —	$ —	$ —	$ 2,397
Investments	—	893	—	—	893
Other long-term assets	510	—	204	—	714
Accounts payable	—	—	—	(775)	(775)
Accrued liabilities	—	—	—	(2,597)	(2,597)
Other long-term liabilities [2]	—	(38)	(65)	(469)	(572)
Long-term debt [1]	—	—	—	(22,458)	(22,458)
	$ 2,907	$ 855	$ 139	$ (26,299)	$ (22,398)

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

(2) Includes $469 million (US$375 million) of deferred purchase consideration which was paid to Marathon in March 2018.

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, 2018			
	Carrying amount	**Fair value**		
Asset (liability) [1] [2]		**Level 1**	**Level 2**	**Level 3**
Investments [3]	**$ 745**	**$ 745**	**$ —**	**$ —**
Other long-term assets [4]	**$ 835**	**$ —**	**$ 272**	**$ 563**
Other long-term liabilities	**$ (16)**	**$ —**	**$ (16)**	**$ —**
Fixed rate long-term debt [5] [6]	**$ (15,223)**	**$ (16,047)**	**$ —**	**$ —**

	Dec 31, 2017			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3
Investments [3]	$ 893	$ 893	$ —	$ —
Other long-term assets [4]	$ 714	$ —	$ 204	$ 510
Other long-term liabilities	$ (103)	$ —	$ (103)	$ —
Fixed rate long-term debt [5] [6]	$ (15,989)	$ (17,259)	$ —	$ —

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

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

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

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

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

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

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 2018**	Dec 31 2017
Derivatives held for trading		
Foreign currency forward contracts	**$ 19**	$ (38)
Natural gas AECO swaps	**(16)**	—
Cash flow hedges		
Foreign currency forward contracts	**19**	(71)
Cross currency swaps	**234**	210
	$ 256	$ 101
Included within:		
Current portion of other long-term assets (liabilities)	**$ 30**	$ (103)
Other long-term assets	**226**	204
	$ 256	$ 101

For the six months ended June 30, 2018, the Company recognized a gain of $nil (year ended December 31, 2017 – gain of $5 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.

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 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 2018**		Dec 31 2017
Balance – beginning of period	**$**	**101**	$	489
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**41**		(37)
Foreign exchange		**156**		(375)
Other comprehensive (loss) income		**(42)**		24
Balance – end of period		**256**		101
Less: current portion		**30**		(103)
	$	**226**	$	204

Net gain from risk management activities were as follows:

	Three Months Ended				Six Months Ended			
		Jun 30 2018		Jun 30 2017		**Jun 30 2018**		Jun 30 2017
Net realized risk management gain	**$**	**(27)**	$	(13)	**$**	**(46)**	$	(25)
Net unrealized risk management gain		**(8)**		(6)		**(41)**		(46)
	$	**(35)**	$	(19)	**$**	**(87)**	$	(71)

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, 2018, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Natural Gas				
AECO swaps	Jul 2018 - Oct 2018	100,000 GJ/d	$1.01	AECO
	Jul 2018 - Oct 2018	200,000 GJ/d	$1.08	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, 2018, 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, 2018, 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	July 2018	—	Nov 2021	US$500	1.022	3.45%	3.96%
	July 2018	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at June 30, 2018 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at June 30, 2018, the Company had US$3,504 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,245 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, 2018, 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, 2018, the Company had net risk management assets of $259 million with specific counterparties related to derivative financial instruments (December 31, 2017 – $187 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 for financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 970	$ —	$ —	$ —
Accrued liabilities	$ 2,542	$ —	$ —	$ —
Other long-term liabilities	$ 16	$ —	$ —	$ —
Long-term debt (1) (2)	$ 977	$ 4,127	$ 6,942	$ 9,482

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

(2) In addition to the financial liabilities disclosed above, estimated interest and other financing payments are as follows: less than one year, $837 million; one to less than two years, $806 million; two to less than five years, $1,739 million; and thereafter, $5,370 million. Interest payments were estimated based upon applicable interest and foreign exchange rates as at June 30, 2018.

17. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$ 344	$ 610	$ 561	$ 541	$ 474	$ 3,892
North West Redwater Partnership service toll (1)	$ 46	$ 79	$ 126	$ 157	$ 158	$ 3,015
Offshore equipment operating leases	$ 91	$ 94	$ 70	$ 68	$ 7	$ —
Office leases	$ 22	$ 42	$ 43	$ 40	$ 31	$ 121
Other	$ 61	$ 44	$ 39	$ 36	$ 39	$ 365

(1) As per 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 service toll is $1,340 million of interest payable over the 30 year tolling period. See note 8.

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

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

18. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Segmented product sales																
Crude oil and NGLs	**2,327**	1,692	**4,169**	3,611	**225**	142	**334**	332	**136**	102	**194**	229	**2,688**	1,936	**4,697**	4,172
Natural gas	**229**	415	**569**	862	**28**	23	**67**	52	**16**	10	**35**	23	**273**	448	**671**	937
Total segmented product sales	**2,556**	2,107	**4,738**	4,473	**253**	165	**401**	384	**152**	112	**229**	252	**2,961**	2,384	**5,368**	5,109
Less: royalties	**(263)**	(176)	**(438)**	(380)	**(1)**	(1)	**(1)**	(1)	**(15)**	(6)	**(20)**	(13)	**(279)**	(183)	**(459)**	(394)
Segmented revenue	**2,293**	1,931	**4,300**	4,093	**252**	164	**400**	383	**137**	106	**209**	239	**2,682**	2,201	**4,909**	4,715
Segmented expenses																
Production	**609**	590	**1,240**	1,161	**100**	76	**175**	186	**40**	52	**69**	98	**749**	718	**1,484**	1,445
Transportation, blending and feedstock	**699**	522	**1,433**	1,154	**6**	7	**12**	18	**—**	1	**1**	1	**705**	530	**1,446**	1,173
Depletion, depreciation and amortization	**780**	773	**1,558**	1,572	**72**	156	**116**	401	**42**	42	**70**	100	**894**	971	**1,744**	2,073
Asset retirement obligation accretion	**22**	20	**44**	39	**7**	7	**14**	14	**3**	2	**5**	4	**32**	29	**63**	57
Risk management activities (commodity derivatives)	**13**	(49)	**13**	(101)	**—**	—	**—**	—	**—**	—	**—**	—	**13**	(49)	**13**	(101)
Gain on acquisition, disposition and revaluation of properties	**—**	(35)	**—**	(35)	**(139)**	—	**(139)**	—	**—**	—	**—**	—	**(139)**	(35)	**(139)**	(35)
Equity loss (gain) from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,123**	1,821	**4,288**	3,790	**46**	246	**178**	619	**85**	97	**145**	203	**2,254**	2,164	**4,611**	4,612
Segmented earnings (loss) before the following	**170**	110	**12**	303	**206**	(82)	**222**	(236)	**52**	9	**64**	36	**428**	37	**298**	103
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange loss (gain)																
Loss (gain) from investments																
Total non–segmented expenses																
Earnings before taxes																
Current income tax expense (recovery)																
Deferred income tax expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				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	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Segmented product sales																
Crude oil and NGLs	**3,266**	1,537	**6,464**	2,682	**25**	23	**52**	48	**92**	149	**161**	202	**6,071**	3,645	**11,374**	7,104
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**45**	34	**79**	78	**318**	482	**750**	1,015
Total segmented product sales	**3,266**	1,537	**6,464**	2,682	**25**	23	**52**	48	**137**	183	**240**	280	**6,389**	4,127	**12,124**	8,119
Less: royalties	**(158)**	(33)	**(239)**	(52)	**—**	—	**—**	—	**—**	—	**—**	—	**(437)**	(216)	**(698)**	(446)
Segmented revenue	**3,108**	1,504	**6,225**	2,630	**25**	23	**52**	48	**137**	183	**240**	280	**5,952**	3,911	**11,426**	7,673
Segmented expenses																
Production	**855**	553	**1,728**	925	**6**	4	**11**	8	**12**	18	**29**	36	**1,622**	1,293	**3,252**	2,414
Transportation, blending and feedstock	**323**	74	**648**	94	**—**	—	**—**	—	**114**	158	**200**	238	**1,142**	762	**2,294**	1,505
Depletion, depreciation and amortization	**372**	237	**776**	432	**4**	2	**7**	4	**—**	—	**—**	—	**1,270**	1,210	**2,527**	2,509
Asset retirement obligation accretion	**15**	10	**30**	18	**—**	—	**—**	—	**—**	—	**—**	—	**47**	39	**93**	75
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**13**	(49)	**13**	(101)
Gain on acquisition, disposition and revaluation of properties	**—**	(230)	**—**	(230)	**—**	—	**—**	—	**—**	—	**—**	—	**(139)**	(265)	**(139)**	(265)
Equity loss (gain) from investments	**—**	—	**—**	—	**2**	(10)	**3**	(12)	**—**	—	**—**	—	**2**	(10)	**3**	(12)
Total segmented expenses	**1,565**	644	**3,182**	1,239	**12**	(4)	**21**	—	**126**	176	**229**	274	**3,957**	2,980	**8,043**	6,125
Segmented earnings (loss) before the following	**1,543**	860	**3,043**	1,391	**13**	27	**31**	48	**11**	7	**11**	6	**1,995**	931	**3,383**	1,548
Non–segmented expenses																
Administration													**76**	75	**157**	162
Share-based compensation													**175**	(104)	**87**	(77)
Interest and other financing expense													**190**	145	**380**	279
Risk management activities (other)													**(48)**	30	**(100)**	30
Foreign exchange loss (gain)													**171**	(347)	**449**	(403)
Loss (gain) from investments													**29**	(23)	**134**	68
Total non–segmented expenses													**593**	(224)	**1,107**	59
Earnings before taxes													**1,402**	1,155	**2,276**	1,489
Current income tax expense (recovery)													**257**	(79)	**411**	(26)
Deferred income tax expense													**163**	162	**300**	198
Net earnings													**982**	1,072	**1,565**	1,317

Capital Expenditures [1]

	Six Months Ended					
	Jun 30, 2018			Jun 30, 2017		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net [3] expenditures	Non-cash and fair value changes [2][3]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [4]	**$ 57**	**$ (81)**	**$ (24)**	$ 89	$ (99)	$ (10)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**7**	**—**	**7**	4	—	4
Oil Sands Mining and Upgrading	**—**	**(7)**	**(7)**	142	117	259
	$ 64	**$ (88)**	**$ (24)**	$ 235	$ 18	$ 253
Property, plant and equipment						
Exploration and Production						
North America	**$ 1,283**	**$ (101)**	**$ 1,182**	$ 1,115	$ 241	$ 1,356
North Sea	**38**	**214**	**252**	76	20	96
Offshore Africa	**62**	**—**	**62**	33	3	36
	1,383	**113**	**1,496**	1,224	264	1,488
Oil Sands Mining and Upgrading [5]	**470**	**(111)**	**359**	8,480	5,777	14,257
Midstream	**9**	**—**	**9**	2	—	2
Head office	**11**	**—**	**11**	22	—	22
	$ 1,873	**$ 2**	**$ 1,875**	$ 9,728	$ 6,041	$ 15,769

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, transfers of property, plant and equipment to inventory due to change in use, and other fair value adjustments.

(3) Net expenditures on exploration and evaluation assets and property, plant and equipment for the six months ended June 30, 2017 exclude non-cash share consideration of $3,818 million issued on the acquisition of AOSP and other assets. This non-cash consideration is included in non-cash and other fair value changes.

(4) The above noted figures for 2017 do not include the impact of a pre-tax cash gain of $35 million on the disposition of certain exploration and evaluation assets.

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

Segmented Assets

	Jun 30 2018	Dec 31 2017
Exploration and Production		
North America	**$ 28,339**	$ 28,705
North Sea	**1,846**	1,854
Offshore Africa	**1,445**	1,331
Other	**46**	29
Oil Sands Mining and Upgrading	**40,521**	40,559
Midstream	**1,372**	1,279
Head office	**110**	110
	$ 73,679	$ 73,867

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 2017. 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, 2018:	
Interest coverage (times)	
Net earnings [(1)]	5.5x
Funds flow from operations [(2)]	12.6x

(1) Net earnings plus income taxes and interest expense excluding current and deferred PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

(2) Funds flow from operations plus current income taxes and interest expense excluding current PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

Corporate Information

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Barry Duncan
Vice-President, Finance, International

Andrew M. McBoyle
Vice-President, Exploitation, International

Stock Listing

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

Registrar and Transfer Agent

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