# CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2019 THIRD QUARTER RESULTS

## CALGARY, ALBERTA – NOVEMBER 7, 2019 – FOR IMMEDIATE RELEASE

Commenting on the Company's third quarter 2019 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "Canadian Natural's third quarter results are an excellent example of how the Company's effective and efficient operations can drive value creation for our shareholders as a result of execution excellence and economies of scale. We achieved record quarterly adjusted funds flow of approximately $2.9 billion as operating costs were below forecast and production was at the top end of quarterly corporate guidance, resulting in 12 month production per share growth of 14% from Q3/18 levels. Free cash flow of approximately $1.9 billion was significant following our disciplined capital expenditures in the quarter. Our free cash flow was used to strengthen our balance sheet and returned to our shareholders, through dividends and share purchases as we balance according to our defined free cash flow allocation policy."

Canadian Natural's President, Tim McKay, added, "The third quarter of 2019 was an excellent operational quarter for the Company. Our continued focus on cost control and effective and efficient operations was evident as operating costs were reduced across most of our assets, resulting in higher netbacks and margin growth. Corporate operating costs per BOE were reduced by approximately 11%, including at our Pelican Lake asset where strong and sustainable operating costs of $6.10/bbl were achieved, a reduction of 5% year over year. Also on a year over year basis our Thermal in situ assets operating costs improved by approximately 14% to $9.77/bbl and our Oil Sands Mining and Upgrading assets delivered an approximate 12% reduction in operating costs to $20.05/bbl of Synthetic Crude Oil ("SCO"), comparable to the record low of $19.97/bbl of SCO in Q4/18.

The Company delivered strong performance in the third quarter, a reflection of our robust assets, effective and efficient operations and our operational flexibility, as we effectively executed our curtailment optimization strategy, delivering production at the top end of quarterly guidance. Oil Sands Mining and Upgrading achieved a record production month in the quarter, producing approximately 462,000 bbl/d of SCO in August 2019. In September and October, as a part of our curtailment optimization strategy, we utilized available capacity from our flexible thermal in situ assets to coincide with the Horizon turnaround ensuring we maximized production within our curtailment allotment. This flexibility demonstrates the value of having a large, balanced and diverse asset base. As a result of top tier execution, the planned turnaround at Horizon was successfully completed on schedule with overall costs under budget."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, continued, "Canadian Natural's robust business model was on display in the third quarter as financial results were strong with net earnings of over $1.0 billion and adjusted net earnings of approximately $1.2 billion.

The Company's long life low decline asset base delivered quarterly record adjusted funds flow of approximately $2.9 billion and as a result free cash flow generation was significant at approximately $1.5 billion after capital expenditures and dividends. Our financial position strengthened in Q3/19 as we reduced gross debt by over $1.0 billion from Q2/19 levels. This included the permanent repayment and cancellation of term debt by $800 million in the quarter, followed by an additional $500 million repayment and cancellation subsequent to quarter end. Based on corporate guidance and current strip pricing we target to exit 2019 with debt to adjusted EBITDA at or below 1.9x, debt to cash flow at or below 2.2x and debt to book capital at or below 38%, all levels that are stronger than those exiting December 31, 2018, notwithstanding the completion of the Devon Canada asset acquisition."

## QUARTERLY HIGHLIGHTS

| ($ millions, except per common share amounts) | Three Months Ended<br>**Sep 30 2019** | <br>Jun 30 2019 | <br>Sep 30 2018 | Nine Months Ended<br>**Sep 30 2019** | <br>Sep 30 2018 |
|---|---|---|---|---|---|
| Net earnings | **$ 1,027** | $ 2,831 | $ 1,802 | **$ 4,819** | $ 3,367 |
| Per common share – basic | **$ 0.87** | $ 2.37 | $ 1.48 | **$ 4.04** | $ 2.75 |
| – diluted | **$ 0.87** | $ 2.36 | $ 1.47 | **$ 4.03** | $ 2.74 |
| Adjusted net earnings from operations (1) | **$ 1,229** | $ 1,042 | $ 1,354 | **$ 3,109** | $ 3,518 |
| Per common share – basic | **$ 1.04** | $ 0.87 | $ 1.11 | **$ 2.61** | $ 2.88 |
| – diluted | **$ 1.04** | $ 0.87 | $ 1.11 | **$ 2.60** | $ 2.86 |
| Cash flows from operating activities | **$ 2,518** | $ 2,861 | $ 3,642 | **$ 6,375** | $ 8,724 |
| Adjusted funds flow (2) | **$ 2,881** | $ 2,652 | $ 2,830 | **$ 7,773** | $ 7,859 |
| Per common share – basic | **$ 2.43** | $ 2.22 | $ 2.32 | **$ 6.51** | $ 6.42 |
| – diluted | **$ 2.43** | $ 2.22 | $ 2.31 | **$ 6.50** | $ 6.39 |
| Cash flows used in investing activities | **$ 908** | $ 4,464 | $ 1,265 | **$ 6,401** | $ 3,772 |
| Net capital expenditures, excluding Devon Canada asset acquisition costs (3) | **$ 963** | $ 908 | $ 1,473 | **$ 2,848** | $ 3,550 |
| Total net capital expenditures, including Devon Canada asset acquisition costs (3) | **$ 963** | $ 4,125 | $ 1,473 | **$ 6,065** | $ 3,550 |
| Daily production, before royalties | | | | | |
| Natural gas (MMcf/d) | **1,469** | 1,532 | 1,553 | **1,504** | 1,568 |
| Crude oil and NGLs (bbl/d) | **931,546** | 770,409 | 801,742 | **829,031** | 816,539 |
| Equivalent production (BOE/d) (4) | **1,176,361** | 1,025,800 | 1,060,629 | **1,079,641** | 1,077,953 |

*(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The derivation of this measure is discussed in the "Advisory" section of this press release.*

*(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key to evaluate its performance as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The derivation of this measure is discussed in the "Advisory" section of this press release.*

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

*(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 $1,027 million were realized in Q3/19, while adjusted net earnings of $1,229 million were achieved in Q3/19, a $187 million increase from Q2/19 levels.
- Cash flows from operating activities were $2,518 million in Q3/19, a decrease of $343 million compared to Q2/19 levels.
- Canadian Natural generated record quarterly adjusted funds flow of $2,881 million in Q3/19, an increase of 9% or $229 million over Q2/19 levels. The increase over Q2/19 was primarily due to higher production volumes from the Company's Thermal in situ, Oil Sands Mining and Upgrading, Primary Heavy and Pelican Lake crude oil segments and strong operating costs which were partially offset by lower light crude oil and heavy crude oil pricing in the quarter.
- Cash flows used in investing activities were $908 million in Q3/19.

- Canadian Natural delivered strong quarterly free cash flow of $1,471 million after net capital expenditures of $963 million, and dividend requirements of $447 million in Q3/19, reflecting the strength of our long life low decline asset base and our effective and efficient operations.
  - Balance sheet strength remains a focus and free cash flow was used to reduce debt levels in Q3/19 as the Company balances its free cash flow according to the defined free cash flow allocation policy. As a result gross long-term debt was reduced in Q3/19 by $1,018 million from Q2/19 levels.
    - The Company utilized adjusted funds flow to repay and cancel $800 million of its $1,800 million non-revolving term loan facility; $1,000 million remained outstanding and fully drawn at quarter end.
      - Subsequent to quarter end the Company repaid and canceled an additional $500 million of the remaining $1,000 million non-revolving term loan; $500 million remains outstanding and fully drawn as at November 6, 2019.
  - Canadian Natural is committed to returns to shareholders, returning a total of $616 million to shareholders in Q3/19, $447 million by way of dividends and $169 million by way of share purchases. In the first nine months of 2019, the Company has returned a total of $2,100 million to shareholders, $1,299 million by way of dividends and $801 million by way of share purchases.
    - Share purchases for cancellation in the quarter totaled 5,050,000 common shares at a weighted average share price of $33.45.
    - Subsequent to quarter end, up to and including November 6, 2019, the Company executed on additional share purchases for cancellation of 1,350,000 common shares at a weighted average share price of $33.70.
    - Returns to shareholders have been significant as Canadian Natural has returned approximately $5.4 billion by way of dividends and share purchases between January 1, 2018 and November 6, 2019.
    - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on January 1, 2020.
- The Company continues to manage within its curtailment optimization strategy which in addition to strong operational performance, contributed to production levels that are at the top end of guidance guidance. The Company continues to execute operational flexibility through its curtailment optimization strategy as follows:
  - Mitigating production impacts, from lower production at Horizon due to planned maintenance activities, by increasing Athabasca Oil Sands Project ("AOSP"), conventional crude oil and thermal in situ crude oil production. As a result, strong production was realized at the Company's North America Exploration and Production ("E&P") and thermal in situ oil sands assets in Q3/19.
  - Modified timing of the Company's planned turnaround activities to achieve its monthly curtailment allowable.
  - Maximizing value through production optimization of higher netback assets and reducing operating costs.
- The Company achieved quarterly production volumes of 1,176,361 BOE/d in Q3/19, increases of 15% and 11% over Q2/19 and Q3/18 levels respectively, reflecting production additions from the Devon Canada asset acquisition that closed on June 27, 2019, together with strong operational performance at both Horizon and AOSP.
  - As a result of accretive acquisitions, effective and efficient operations and execution on the Company's free cash flow allocation policy, annual production per share growth was significant at 14% when compared to Q3/18 levels.
  - The Company achieved record quarterly liquids production volumes of 931,546 bbl/d in Q3/19, increases of 21% and 16% over Q2/19 and Q3/18 levels respectively and at the top end of previously issued guidance.
- At the Company's world class Oil Sands Mining and Upgrading assets, production volumes were strong, at the top end of production guidance, averaging 432,203 bbl/d of Synthetic Crude Oil ("SCO") in Q3/19, increases of 15% and 10% over Q2/19 and Q3/18 levels respectively. The increases were primarily as a result of strong operational performance as well as modified timing of the Horizon turnaround schedule as a part of the Company's curtailment optimization strategy.
  - Effective and efficient operations and high reliability resulted in strong quarterly operating costs of $20.05/bbl (US$15.18/bbl) of SCO in Q3/19, comparable to record low operating costs of $19.97/bbl (US$15.12/bbl) of SCO achieved in Q4/18, impressive results given the planned turnaround activities in the quarter. Q3/19 operating costs represent decreases of 17% and 12% from Q2/19 and Q3/18 levels respectively.
  - At the Albian mines, top tier operations combined with enhancing and optimization of equipment resulted in record gross bitumen production averaging approximately 318,000 bbl/d in September and October, forming a part of

the Company’s curtailment optimization strategy during the Horizon turnaround. These results are significant as the two month average throughput was approximately 38,000 bbl/d or 14% above capability announced at the time of the acquisition. The Company continues to maximize value from acquired assets through lower operating costs and enhancing and optimizing production.

    - At Horizon, subsequent to quarter end the Company successfully completed a planned turnaround on schedule and under budget demonstrating strong execution by the Company's teams.
    - As part of the Company’s proactive inspection at Horizon, the team identified a need to repair piping on one of the hydrogen manufacturing units during post turnaround start-up. As a result, Horizon is currently running at restricted rates of approximately 155,000 bbl/d and is targeted to return to full rates by early December 2019. The Company’s targets to remain within its previous annual production guidance range.

- Thermal in situ oil sands production volumes exceeded the top end of quarterly production guidance as the Company demonstrated the flexibility and available capacity of its thermal in situ assets by utilizing allowable volumes during the Horizon turnaround of approximately 28,000 bbl/d in September from Jackfish, Kirby North and pad additions at Primrose. Production in Q3/19 averaged 206,395 bbl/d, an 88% increase over Q2/19 levels, primarily reflecting a full quarter of production from the Devon Canada asset acquisition and the successful execution on the Company's curtailment optimization strategy.
    - Thermal in situ operating costs were strong in Q3/19 at $9.77/bbl, reductions of 17% and 14% from Q2/19 and Q3/18 levels respectively, primarily as a result of synergies captured to date from the Devon Canada acquisition and lower energy costs.
    - At Kirby North, top tier execution and productivity have resulted in production averaging approximately 6,600 bbl/d in September 2019, exceeding production forecasts. Strong performance results are primarily due to improved well design, high plant reliability and other operational improvements. Production volumes will be managed as part of the Company's curtailment optimization strategy as the Company ramps up towards Kirby North's overall capacity of 40,000 bbl/d targeted in early 2021.
    - At Primrose, as a result of strong execution the Company's high return pad additions came on ahead of schedule and on budget. Production from the pad additions were strong, beginning on September 16, 2019, utilizing available oil processing and steam capacity with managed production averaging approximately 13,600 bbl/d in September, offsetting production impacts from the planned turnaround at Horizon as part of the Company's curtailment optimization strategy.
    - At Jackfish, pad additions that have been successfully drilled and not completed to date due to curtailments in Alberta have a production capability of 21,000 bbl/d. These pads require minimal capital of approximately $8 million to complete tie in activities that are targeted for Q4/19. Production from these pads is targeted to offset conventional production declines with long life low decline thermal in situ production, as the Company manages within its curtailment optimization strategy and targets to reach peak production in 2022.
- The Company continues to execute its plan to achieve its initially identified targeted annual cost savings of at least $135 million for both primary heavy and thermal in situ crude oil assets acquired from Devon Canada. As previously announced, approximately $25 million of these initially identified synergies are being realized more than one year ahead of the initial plan.
    - Additionally, in the short time since closing Canadian Natural has identified incremental targeted annual savings of approximately $10 million and approximately $50 million of one time capital cost savings on its thermal in situ and primary heavy crude oil assets driving incremental value for the Company's shareholders.
- Canadian Natural's continued focus on delivering effective and efficient operations and cost control was demonstrated as the Company's E&P Q3/19 operating costs were $11.11/BOE, 5% and 7% reductions from Q2/19 and Q3/18 levels respectively.
- Canadian Natural's North America E&P crude oil and NGLs production volumes, excluding thermal in situ, averaged 244,267 bbl/d in Q3/19, a 4% increase over Q2/19 and in line with Q3/18 levels. The increase over Q2/19 was primarily due to a full quarter of production from primary heavy crude oil assets acquired from Devon Canada.
    - At Pelican Lake the Company continues to demonstrate effective and efficient operations as operating costs have averaged approximately $6.50/bbl over the last 4 years. These sustainable and consistent results continued in Q3/19 where operating costs of $6.10/bbl were achieved, representing decreases of 9% and 5% from Q2/19 and Q3/18 levels respectively. The reductions were mainly as a result of the Company's focus on cost control and savings achieved from facility consolidation completed in Q2/19.

- International E&P production volumes were strong in Q3/19, exceeding quarterly production guidance, averaging 48,681 bbl/d, a decrease of 5% from Q2/19 and an increase of 2% over Q3/18 levels. The decrease from Q2/19 is primarily due to planned turnaround activities in the North Sea and natural field declines partially offset by strong performance from new wells. The increase from Q3/18 was primarily as a result of strong volumes from new wells drilled at Baobab and in the North Sea in late 2018 and 2019.
- Corporate natural gas production averaged 1,469 MMcf/d in Q3/19, exceeding the top end of quarterly guidance as a result of phasing of turnaround activities. As compared to Q2/19 and Q3/18 levels, natural gas production decreased by 4% and 5% respectively, primarily due to natural field declines and reduced capital investment.
  - Strong operating costs of $1.12/Mcf were achieved in Q3/19, decreases of 9% and 16% from Q2/19 and Q3/18 levels respectively. The operating cost decreases were primarily due to the Company's continued focus on cost control and the impact of increased processed volumes at strategically owned and operated facilities.
- Incremental egress of approximately 225,000 bbl/d to move incremental crude oil production out of the Western Canadian Sedimentary Basin ("WCSB") is targeted to be added over the near term, providing opportunities for the Company before new export pipelines are constructed:
  - Mainline enhancements are targeted to add approximately 85,000 bbl/d of capacity targeted to be available in December 2019.
  - Express pipeline optimization expansion is targeted to add approximately 50,000 bbl/d of capacity in Q1/20.
  - The North West Redwater Refinery ("NWR") is targeted to add approximately 40,000 bbl/d of incremental crude oil conversion capacity. Upon start-up, the refinery will process a total of approximately 80,000 bbl/d of diluted bitumen, increasing effective takeaway capacity out of the WCSB.
  - Base Keystone export pipeline optimization expansion of approximately 50,000 bbl/d was recently announced. In Q3/19, Canadian Natural committed to approximately 10,000 bbl/d of the expansion, which is targeted to be available early in 2020.
  - Crude by rail volumes continue to be strong at approximately 310,000 bbl/d for the month of August 2019.

## OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

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

Augmenting this, Canadian Natural maintains a substantial inventory of low capital exposure projects within the Company's conventional asset base. These projects can be executed quickly and with the right economic conditions, can provide excellent returns and maximize value for shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs which can be optimized over time. Additionally, by owning and operating most of the related infrastructure, Canadian Natural is able to control major components of the Company's operating costs and minimize production commitments. Low capital exposure projects can be quickly stopped or started depending upon success, market conditions, or corporate needs.

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

### Drilling Activity

| | Nine Months Ended Sep 30 | | | |
|---|---|---|---|---|
| | **2019** | | 2018 | |
| (number of wells) | **Gross** | **Net** | Gross | Net |
| Crude oil | **80** | **74** | 402 | 381 |
| Natural gas | **21** | **15** | 19 | 15 |
| Dry | **3** | **3** | 7 | 7 |
| Subtotal | **104** | **92** | 428 | 403 |
| Stratigraphic test / service wells | **411** | **358** | 617 | 524 |
| Total | **515** | **450** | 1,045 | 927 |
| Success rate (excluding stratigraphic test / service wells) | | **97%** | | 98% |

- The Company's total crude oil and natural gas drilling program of 92 net wells for the nine months ended September 30, 2019, excluding strat/service wells, represents a decrease of 311 net wells from the same period in 2018. The Company's drilling levels primarily reflect the impacts of reduced capital allocation as a result of Alberta curtailments and execution of the Company's curtailment optimization strategy.

### North America Exploration and Production

*Crude oil and NGLs – excluding Thermal In Situ Oil Sands*

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **Sep 30 2019** | Jun 30 2019 | Sep 30 2018 | **Sep 30 2019** | Sep 30 2018 |
| Crude oil and NGLs production (bbl/d) | **244,267** | 235,066 | 247,314 | **234,944** | 243,857 |
| Net wells targeting crude oil | **33** | 9 | 140 | **70** | 299 |
| Net successful wells drilled | **33** | 7 | 135 | **68** | 292 |
| Success rate | **100%** | 78% | 96% | **97%** | 98% |

- Canadian Natural's North America E&P crude oil and NGLs production volumes, excluding thermal in situ, averaged 244,267 bbl/d in Q3/19, a 4% increase over Q2/19 and in line with Q3/18 levels. The increase was primarily due to a full quarter of production from the acquired primary heavy crude oil assets from Devon Canada.

- Canadian Natural's primary heavy crude oil production averaged 88,008 bbl/d in Q3/19, a 13% increase over Q2/19 levels primarily due to additional volumes from the Devon Canada asset acquisition. Primary heavy crude oil production decreased by 4% from Q3/18 levels primarily due to curtailments and natural field declines, partially offset by additional volumes from the Devon Canada asset acquisition.
  - Operating costs of $17.08/bbl were achieved in the Company's primary heavy crude oil operations in the quarter, a 3% decrease from Q2/19 levels.
  - As a result of curtailments in Alberta the Company drilled 7 net primary heavy crude oil wells in Saskatchewan in Q3/19, targeting strategic opportunities for future development, as these wells are not impacted by curtailment. Canadian Natural is leveraging the Company's multilateral horizontal technology expertise on these wells where early results of approximately 140 bbl/d per well are in line with expectations.
- Pelican Lake quarterly production averaged 60,146 bbl/d in Q3/19, an increase of 9% from Q2/19 levels, reflecting normal production levels after the temporary shut-in of crude oil production in Q2/19 due to wildfires in northern Alberta.
  - At Pelican Lake the Company continues to demonstrate effective and efficient operations as operating costs have averaged approximately $6.50/bbl over the last 4 years. These sustainable and consistent results continued in Q3/19 where operating costs of $6.10/bbl were achieved, representing decreases of 9% and 5% from Q2/19 and Q3/18 levels respectively. The reductions were mainly as a result of the Company's focus on cost control and savings achieved from facility consolidation completed in Q2/19.
- North American light crude oil and NGL production averaged 96,113 bbl/d in Q3/19, a 6% decrease from Q2/19 levels primarily as a result of curtailments in Alberta and natural field declines. Production increased 3% from Q3/18 levels reflecting the Company's strategic decision to reallocate capital to light crude oil and liquids rich areas, along with strong results from the 2018 and 2019 drilling programs at Wembley, Karr, and Southeast Saskatchewan combined with the execution of the Company's curtailment optimization strategy.
  - In Q3/19 operating costs were $14.96/bbl in the Company's North America light crude oil and NGL areas, an increase of 2% over Q2/19 and a decrease of 4% from Q3/18 levels. The changes from Q2/19 and Q3/18 levels primarily reflect changes in production volumes noted above and the Company's focus on cost control.
  - Within the greater Wembley area, results from the 27 net wells drilled in 2018 and 3 net wells drilled in 2019 continue to be strong with production averaging approximately 10,400 bbl/d liquids and 68 MMcf/d, exceeding expectations by approximately 40%.
  - In Southeast Saskatchewan, the Company drilled 8 gross (6.6 net) light crude oil wells in Q3/19, with 3 gross (3.0 net) wells previously drilled in Q2/19 as a part of the program. These high return wells came on stream in Q3/19 with strong initial rates from the total program averaging approximately 100 bbl/d per well, exceeding expectations. The Company strategically reallocated conventional capital from Alberta to Saskatchewan as production from these wells is not impacted by the Government of Alberta mandated production curtailment.

▪ The Company’s annual 2019 North America E&P crude oil and NGL production guidance remains unchanged and is targeted to range between 231,000 bbl/d - 251,000 bbl/d.

*Thermal In Situ Oil Sands*

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **Sep 30 2019** | Jun 30 2019 | Sep 30 2018 | **Sep 30 2019** | Sep 30 2018 |
| Bitumen production (bbl/d) | **206,395** | 109,599 | 112,542 | **137,124** | 109,769 |
| Net wells targeting bitumen | **—** | — | 41 | **—** | 84 |
| Net successful wells drilled | **—** | — | 41 | **—** | 84 |
| Success rate | **—** | — | 100% | **—** | 100% |

▪ Thermal in situ oil sands production volumes exceeded the top end of quarterly production guidance as the Company demonstrated the flexibility and available capacity of its thermal in situ assets by utilizing allowable volumes during the Horizon turnaround of approximately 28,000 bbl/d in September from Jackfish, Kirby North and pad additions at Primrose. Production in Q3/19 averaged 206,395 bbl/d, an 88% increase over Q2/19 levels, primarily reflecting a full quarter of production from the Devon Canada asset acquisition and the successful execution on the Company's curtailment optimization strategy.

- Thermal in situ operating costs were strong in Q3/19 at $9.77/bbl, reductions of 17% and 14% from Q2/19 and Q3/18 levels respectively, primarily as a result of synergies captured to date from the Devon Canada acquisition and lower energy costs.
- At Primrose, Q3/19 production volumes averaged 73,652 bbl/d, an increase of 2% over Q2/19 levels, primarily due to execution on the Company's curtailment optimization strategy. Including energy costs, operating costs were strong at $9.91/bbl in Q3/19, decreases of 20% and 16% from Q2/19 and Q3/18 levels respectively, reflecting the Company's focus on cost control, higher volumes and lower energy costs.
  - At Primrose, as a result of strong execution the Company's high return pad additions came on ahead of schedule and on budget. Production from the pad additions were strong, beginning on September 16, 2019, utilizing available oil processing and steam capacity with managed production averaging approximately 13,600 bbl/d in September, offsetting production impacts from the planned turnaround at Horizon as part of the Company's curtailment optimization strategy.
- At Kirby, which now includes both Kirby South and Kirby North projects, Steam Assisted Gravity Drainage ("SAGD") production volumes averaged 31,260 bbl/d in Q3/19, a 9% increase over Q2/19 and a 13% decrease from Q3/18 levels. The increase from Q2/19 was primarily as a result of strong initial Kirby North production. Including energy costs, Kirby quarterly operating costs were strong at $8.69/bbl in Q3/19, reductions of 18% and 5% from Q2/19 and Q3/18 levels respectively, primarily as a result of the Company's focus on cost control, higher production volumes and lower energy costs.
  - Results from the first five months of the Company's solvent enhanced SAGD pilot at Kirby South continue to be positive, indicating that targeted reductions of 30% to 50% to Steam to Oil Ratios ("SORs") remain achievable. If success continues during the two year duration of the pilot, solvent enhanced SAGD has the potential to significantly reduce SORs, operating costs and greenhouse gas emissions by upwards of 50%, if fully commercialized.
  - At Kirby North, top tier execution and productivity have resulted in production averaging approximately 6,600 bbl/d in September 2019, exceeding production forecasts. Strong performance results are primarily due to improved well design, high plant reliability and other operational improvements. Production volumes will be managed as part of the Company's curtailment optimization strategy as the Company ramps up towards Kirby North's overall capacity of 40,000 bbl/d targeted in early 2021.
- At Jackfish, SAGD production volumes averaged 97,537 bbl/d in Q3/19. Including energy costs, Jackfish quarterly operating costs were strong at $9.44/bbl in Q3/19, approximately $3.00/bbl lower than operating cost indications for the asset at time of the acquisition primarily as a result of lower energy costs and synergies captured to date.
  - At Jackfish, pad additions that have been successfully drilled and not completed to date due to curtailments in Alberta have a production capability of 21,000 bbl/d. These pads require minimal capital of approximately $8 million to complete tie in activities that are targeted for Q4/19. Production from these pads is targeted to offset conventional production declines with long life low decline thermal in situ production, as the Company manages within its curtailment optimization strategy and targets to reach peak production in 2022.

▪ The Company’s annual 2019 thermal in situ production guidance remains unchanged and is targeted to range between 157,000 bbl/d - 172,000 bbl/d.

*North America Natural Gas*

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **Sep 30 2019** | Jun 30 2019 | Sep 30 2018 | **Sep 30 2019** | Sep 30 2018 |
| Natural gas production (MMcf/d) | **1,425** | 1,482 | 1,489 | **1,454** | 1,506 |
| Net wells targeting natural gas | **5** | 2 | 6 | **16** | 15 |
| Net successful wells drilled | **5** | 2 | 6 | **15** | 15 |
| Success rate | **100%** | 100% | 100% | **94%** | 100% |

▪ North America natural gas production was 1,425 MMcf/d in Q3/19, decreases of 4% from both Q2/19 and Q3/18 levels. The decreases were primarily due to natural field declines and reduced capital investment.

- Strong operating costs of $1.07/Mcf were achieved in Q3/19, decreases of 7% and 11% from Q2/19 and Q3/18 levels respectively. The operating cost decreases were primarily due to the Company's continued focus on cost control and the impact of increased processed volumes at strategically owned and operated facilities.
  - Septimus operating costs were strong at $0.26/Mcfe in Q3/19, decreases of 21% and 26% from Q2/19 and Q3/18 levels respectively. Focus on cost control supports the Company's high value liquids rich development at Septimus.
- The Company's natural gas reinjection pilot at Septimus commenced its first injection of 5 MMcf/d in Q2/19. Depending on results of the pilot, this technology has the potential to materially increase liquids recovery while storing natural gas in the reservoir, preserving the value of the natural gas for periods with higher market prices.
  - Initial results from the pilot are targeted for late 2019 with the potential to proceed with additional cycles at the same location. Given the opportunities for this process across Canadian Natural's vast liquids rich Montney land base, the Company is advancing readiness for a second pilot site within the Company's Greater Wembley area.
- In 2019 the Company strategically reallocated capital from crude oil projects to the Company's liquids rich Gold Creek assets, which are not subject to curtailment. In Q3/19, 2 net wells came on production averaging approximately 660 bbl/d and 4 MMcf/d per well, exceeding expectations by approximately 110 bbl/d or 20% per well.
- At Pine River, the Company's planned plant turnaround began in mid-September and was completed on November 6, 2019. The turnaround was designed to improve plant efficiency, run time, lower operating costs, and improve plant capability to 120 MMcf/d from current levels of 95 MMcf/d.
- In Q3/19, based upon corporate quarterly Natural Gas production, Canadian Natural used the equivalent of approximately 44% within its operations, providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 32% of the Company's Q3/19 natural gas production was exported to other North American markets and sold internationally, with the remaining 24% of the Company's Q3/19 natural gas production exposed to AECO/Station 2 pricing.
- The Company’s annual 2019 corporate natural gas production guidance remains unchanged and is targeted to range between 1,485 MMcf/d - 1,545 MMcf/d.

**International Exploration and Production**

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **Sep 30 2019** | Jun 30 2019 | Sep 30 2018 | **Sep 30 2019** | Sep 30 2018 |
| Crude oil production (bbl/d) | | | | | |
| North Sea | **27,454** | 27,594 | 28,702 | **26,927** | 24,940 |
| Offshore Africa | **21,227** | 23,650 | 18,802 | **22,341** | 18,812 |
| Natural gas production (MMcf/d) | | | | | |
| North Sea | **20** | 23 | 38 | **24** | 35 |
| Offshore Africa | **24** | 27 | 26 | **26** | 27 |
| Net wells targeting crude oil | **3.0** | 0.9 | 1.6 | **5.5** | 4.5 |
| Net successful wells drilled | **3.0** | 0.9 | 1.6 | **5.5** | 4.5 |
| Success rate | **100%** | 100% | 100% | **100%** | 100% |

- International E&P production volumes were strong in Q3/19, exceeding quarterly production guidance, averaging 48,681 bbl/d, a decrease of 5% from Q2/19 and an increase of 2% over Q3/18 levels. The decrease from Q2/19 is primarily due to planned turnaround activities in the North Sea and natural field declines partially offset by strong performance from new wells. The increase from Q3/18 was primarily as a result of strong volumes from new wells drilled at Baobab and in the North Sea in late 2018 and 2019.
- International production volumes benefit from premium Brent pricing, generating significant free cash flow for the Company.
  - In the North Sea, production volumes of 27,454 bbl/d were achieved in Q3/19, comparable to Q2/19 and a 4% decrease from Q3/18 levels. The decrease from Q3/18 was primarily as a result of planned maintenance activities and natural field declines partly offset by volumes from new wells.

- Q3/19 operating costs in the North Sea averaged $37.11/bbl (£23.04/bbl), in line with Q2/19 and Q3/18 levels.
- The Company completed its 2019 drilling program in Q3/19 drilling 3 gross (3.0 net) high netback producer wells. Initial production from the total drilling program consisting of 5 gross (4.9 net) wells is exceeding expectations by approximately 1,300 bbl/d net per well in the quarter.

- Offshore Africa production volumes in Q3/19 averaged 21,227 bbl/d, a decrease of 10% from Q2/19 and an increase of 13% over Q3/18 levels. The decrease from Q2/19 was primarily as a result of natural field declines and turnaround activities in the quarter. The increase from Q3/18 was primarily as a result of production from new wells drilled late in 2018 and early in 2019 at Baobab, partially offset by natural field declines.
  - Côte d'Ivoire crude oil operating costs averaged $11.06/bbl (US$8.42/bbl) in Q3/19, an increase of 32% from Q2/19 and a decrease of 21% from Q3/18 levels primarily due to timing of liftings from various fields that have different cost structures.
  - Following the previously announced discovery of significant gas condensate in South Africa, where Canadian Natural has a 20% working interest, the operator is preparing to commence a comprehensive 3D and 2D seismic acquisition program in Q4/19, with targeted completion in Q2/20.
    - The operator has contracted a rig with targeted spud of an exploration well in the first half of 2020. Depending on the results of this well, the operator may drill an additional well in 2020 to further define volumes and deliverability.
    - Canadian Natural is carried to a maximum gross cost of approximately US$300 million.

- The Company's annual 2019 International production guidance remains unchanged and is targeted to range from 46,000 bbl/d - 50,000 bbl/d.

**North America Oil Sands Mining and Upgrading**

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **Sep 30 2019** | Jun 30 2019 | Sep 30 2018 | **Sep 30 2019** | Sep 30 2018 |
| Synthetic crude oil production (bbl/d) (1) (2) | **432,203** | 374,500 | 394,382 | **407,695** | 419,161 |

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

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

- At the Company's world class Oil Sands Mining and Upgrading assets, production volumes were strong, at the upper end of production guidance, averaging 432,203 bbl/d of SCO in Q3/19, increases of 15% and 10% over Q2/19 and Q3/18 levels respectively. The increases were primarily as a result of strong operational performance as well as modified timing of the Horizon turnaround schedule as a part of the Company's curtailment optimization strategy.
  - Effective and efficient operations and high reliability resulted in strong quarterly operating costs of $20.05/bbl (US$15.18/bbl) of SCO in Q3/19, comparable to record low operating costs of $19.97/bbl (US$15.12/bbl) of SCO achieved in Q4/18, impressive results given the planned turnaround activities in the quarter. Q3/19 operating costs represent decreases of 17% and 12% from Q2/19 and Q3/18 levels respectively.
    - Total production costs were $784 million in Q3/19, $30 million lower than Q2/19. Production costs for the first nine months of 2019 were $2,420 million, a 6% or $150 million decrease from the comparable period in 2018, demonstrating the Company's focus on effective and efficient operations.
  - At the Albian mines, top tier operations combined with enhancing and optimization of equipment resulted in record gross bitumen production averaging approximately 318,000 bbl/d in September and October, forming a part of the Company’s curtailment optimization strategy during the Horizon turnaround. These results are significant as the two month average throughput was approximately 38,000 bbl/d or 14% above capability announced at the time of the acquisition. The Company continues to maximize value from acquired assets through lower operating costs and enhancing and optimizing production.
  - At Horizon, subsequent to quarter end the Company successfully completed a planned turnaround on schedule and under budget demonstrating strong execution by the Company's teams.
  - The Company continues to progress engineering work on a prudent basis for potential expansion opportunities at Horizon to increase reliability and lower costs, targeting to add production of 75,000 bbl/d to 95,000 bbl/d. The final investment decision on these opportunities will not be made until there is greater clarity on market access.

- The Company's annual 2019 Oil Sands Mining and Upgrading production guidance remains unchanged and is targeted to range between 405,000 bbl/d - 415,000 bbl/d of SCO.

## MARKETING

| | Three Months Ended | | | Nine Months Ended | |
|---|---|---|---|---|---|
| | **Sep 30 2019** | Jun 30 2019 | Sep 30 2018 | **Sep 30 2019** | Sep 30 2018 |
| Crude oil and NGLs pricing | | | | | |
| WTI benchmark price (US$/bbl) (1) | **$ 56.45** | $ 59.83 | $ 69.50 | **$ 57.06** | $ 66.79 |
| WCS heavy differential as a percentage of WTI (%) (2) | **22%** | 18% | 32% | **21%** | 33% |
| SCO price (US$/bbl) | **$ 56.87** | $ 59.96 | $ 68.44 | **$ 56.36** | $ 65.75 |
| Condensate benchmark pricing (US$/bbl) | **$ 52.00** | $ 55.86 | $ 66.82 | **$ 52.79** | $ 66.28 |
| Average realized pricing before risk management (C$/bbl) (3) | **$ 55.19** | $ 63.45 | $ 57.89 | **$ 57.49** | $ 54.26 |
| Natural gas pricing | | | | | |
| AECO benchmark price (C$/GJ) | **$ 0.99** | $ 1.11 | $ 1.28 | **$ 1.31** | $ 1.33 |
| Average realized pricing before risk management (C$/Mcf) | **$ 1.64** | $ 1.98 | $ 2.32 | **$ 2.24** | $ 2.34 |

*(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.*

- Incremental egress of approximately 225,000 bbl/d to move incremental crude oil production out of the WCSB is targeted to be added over the near term, providing opportunities for the Company before new export pipelines are constructed:
  - Mainline enhancements are targeted to add approximately 85,000 bbl/d of capacity targeted to be available in December 2019.
  - Express pipeline optimization expansion is targeted to add approximately 50,000 bbl/d of capacity in Q1/20.
  - The NWR Refinery is targeted to add approximately 40,000 bbl/d of incremental crude oil conversion capacity. Upon start-up, the refinery will process a total of approximately 80,000 bbl/d of diluted bitumen, increasing effective takeaway capacity out of the WCSB.
  - Base Keystone export pipeline optimization expansion of approximately 50,000 bbl/d was recently announced. In Q3/19, Canadian Natural committed to approximately 10,000 bbl/d of the expansion, which is targeted to be available early in 2020.
  - Crude by rail volumes continue to be strong at approximately 310,000 bbl/d for the month of August 2019.
- Q3/19 differentials between WCS and WTI benchmark pricing narrowed from Q3/18 levels following the Government of Alberta's announcement of mandatory curtailments of crude oil production that came into effect January 1, 2019.
- AECO natural gas prices decreased in Q3/19 from Q2/19 and Q3/18 levels, reflecting pipeline egress constraints out of the basin as well as increased natural gas production in North America.
  - During Q3/19, TC Energy announced the Temporary Service Protocol ("TSP") on the Nova Gas Transmission Line that targets to manage system constraints during planned outages and maintenance during the summer months (April through October). TSP targets to be in place until October 2020, potentially resulting in reduced volatility of AECO benchmark pricing over that period.
- The NWR refinery, upon completion, targets to strengthen the Company's position by providing a competitive return on investment and by creating incremental demand for approximately 80,000 bbl/d of heavy crude oil blends that will not require export pipelines, helping to reduce pricing volatility in all Western Canadian heavy crude oil.
  - The Company has a 50% interest in the NWR Partnership. For updates on the project, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.

## ENVIRONMENTAL HIGHLIGHTS

- In July 2019, Canadian Natural published its 2018 Stewardship Report to Stakeholders, which is available on the Company's website at https://www.cnrl.com/report-to-stakeholders. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. Highlights from the 2018 report are as follows:
- In the report, the Company confirmed that 100% of direct emissions from our Alberta oil sands in situ and mining operations were third party verified. The 2018 verification was completed by professional engineering firm GHD Limited.
  - Canadian Natural's corporate greenhouse gas ("GHG") emissions intensity has decreased by approximately 29% from 2012 to 2018, a material reduction in emissions intensity.
  - The Company's corporate GHG emissions intensity decreased in 2018 by approximately 29% from 2012 levels, including a reduction of approximately 37% at Horizon Oil Sands.
    - The Company's corporate GHG emissions intensity decreased in 2018 by approximately 5% from 2017 levels, including a reduction of approximately 18% in Oil Sands Mining and Upgrading.
  - Methane emissions have decreased 78% from 2012 to 2018 at the Company's Alberta primary heavy conventional crude oil operations.
  - In the Company's North America E&P segment, in 2018 natural gas flaring decreased by 4% and natural gas venting decreased by 6% from 2017 levels.
  - In 2018, in the Company's North America E&P segment, Canadian Natural abandoned 1,293 wells, an increase of 68% over 2017 levels, and submitted 1,012 reclamation certificates, an increase of approximately 67% over 2017 levels.
  - The Company reclaimed 1,383 hectares of land in 2018 in the Company's North America E&P segment, equivalent to approximately 1,700 Canadian football fields and a 9% increase over 2017 levels.
  - In the Oil Sands Mining and Upgrading segment, water use intensity decreased in 2018 by 30% from 2017 levels.
  - Approximately 75% of water used at Primrose was sourced from recycled produced water in 2018.
- Canadian Natural has invested over $3.4 billion in research and development from 2009 to 2018 year ended and continues to invest in technology to unlock reserves, become more effective and efficient, increase production and reduce the Company's environmental footprint. Canadian Natural's culture of continuous improvement leverages the use of technology and innovation to drive sustainable operations and long-term value for shareholders.
- Canadian Natural has invested significant capital to capture and sequester $CO_2$. The Company has carbon capture and sequestration facilities at Horizon, a 70% working interest in the Quest Carbon Capture and Storage project at Scotford, and by way of carbon capture facilities at its 50% interest in the NWR refinery when on stream. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of $CO_2$ annually, equivalent to taking 576,000 vehicles off the road per year, making the Company one of the largest $CO_2$ capturer and sequester for the oil and natural gas sector globally.
- Canadian Natural's commitment to leverage technology, adopting innovation and continuous improvement is evidenced by its In Pit Extraction Process ("IPEP") pilot at Horizon, which will determine the feasibility of producing stackable dry tailings. The project has the potential to reduce the Company's carbon emissions and environmental footprint by reducing the distance driven by its fleet of haul trucks, the size and need for tailings ponds and accelerating site reclamation. In addition, this process has the potential to significantly reduce capital and operating costs.
  - The initial testing phase for the Company's IPEP pilot has concluded and results have been positive, with excellent recovery rates and evidence of stackable tailings. Given that the pilot continues to produce positive results, the Company is targeting to proceed with pilot enhancements in 2020.

## FINANCIAL REVIEW

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

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production levels of 1,176,361 BOE/d in Q3/19, with approximately 98% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with Q3/19 production mix on a BOE/d basis of 49% light crude oil and SCO blends, 30% heavy crude oil blends and 21% natural gas.
- Canadian Natural delivered strong quarterly free cash flow of $1,471 million after net capital expenditures of $963 million, and dividend requirements of $447 million in Q3/19, reflecting the strength of our long life low decline asset base and our effective and efficient operations.
  - Balance sheet strength remains a focus and free cash flow was used to reduce debt levels in Q3/19 as the Company balances its free cash flow according to the defined free cash flow allocation policy. As a result gross long-term debt was reduced in Q3/19 by $1,018 million from Q2/19 levels.
  - Net long-term debt was reduced by $796 million to $22,313 million in Q3/19.
  - The Company utilized adjusted funds flow to repay and cancel $800 million of the $1,800 million non-revolving term loan facility; $1,000 million remained outstanding and fully drawn at quarter end.
    - Subsequent to quarter end the Company repaid and canceled an additional $500 million of the remaining $1,000 million non-revolving term loan; $500 million remains outstanding and fully drawn as at November 6, 2019.
  - Debt to book capitalization strengthened to 39.1% in Q3/19.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At September 30, 2019 the Company had approximately $4,680 million of available liquidity, including cash and cash equivalents, an increase of approximately $120 million over Q2/19 levels.
  - Canadian Natural is committed to returns to our shareholders, returning a total of $616 million in Q3/19, $447 million by way of dividends and $169 million by way of share purchases. In the first nine months of 2019, the Company has returned a total of $2,100 million to our shareholders, $1,299 million by way of dividends and $801 million by way of share purchases.
    - Share purchases for cancellation in the quarter totaled 5,050,000 common shares at a weighted average share price of $33.45.
    - Subsequent to quarter end, up to and including November 6, 2019, the Company executed on additional share purchases for cancellation of 1,350,000 common shares at a weighted average share price of $33.70.
    - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on January 1, 2020.
- In addition to the Company's strong adjusted funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at September 30, 2019, these financial levers include the Company's third party equity investments of $567 million, and cross currency swaps with a total value of $321 million.
- In 2018, the Board of Directors approved a more defined free cash flow allocation policy in accordance with the Company's four stated pillars. Under the policy, in 2019 the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures, dividends and large opportunistic acquisitions, to share purchases under its NCIB and the remaining 50% to reducing debt levels on the Company's balance sheet. This free cash flow policy will target a ratio of debt to adjusted 12 months trailing EBITDA of 1.5x, and an absolute debt level of $15.0 billion, at which time the policy will be reviewed by the Board. This policy was effective November 1, 2018.

## CORPORATE UPDATE

Canadian Natural is pleased to announce the appointment of Dr. M. Elizabeth Cannon to the Board of Directors of the Company, effective November 5, 2019. Dr. M. Elizabeth Cannon is currently President Emerita and Professor of Engineering at the University of Calgary having previously served at the University of Calgary as Dean of the Schulich School of Engineering from 2006-2010, President and Vice Chancellor from 2010 to 2018. Dr. Cannon is a fellow of the Royal Society of Canada and the Canadian Academy of Engineering, an associate of the National Academy of Engineering (US) and a corresponding member of the Mexican Academy of Engineering. She has served on the federal government's Science, Technology and Innovation Council, is past president of the U.S. Institute of Navigation, and is a past director of the Canada Foundation for Innovation. Dr. Cannon holds a Bachelor of Applied Sciences (Mathematics) from Acadia University as well as Bachelor of Science, Master of Science and a PhD in Geomatics Engineering, all from the University of Calgary. Dr. Cannon is a professional engineer and an APEGA member. She also holds Honorary Doctorates from 3 universities as well as an Honorary Bachelor of Business Administration from SAIT.

## OUTLOOK

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

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

## ADVISORY

### Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the “Company”) in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words “believe”, “anticipate”, “expect”, “plan”, “estimate”, “target”, “continue”, “could”, “intend”, “may”, “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “schedule”, “proposed” or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other guidance provided throughout this Management’s Discussion and Analysis (“MD&A”) of the financial condition and results of operations of the Company, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the timing and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil (“SCO”) that the Company may be reliant upon to transport its products to market, and the development and deployment of technology and technological innovations also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); 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 the Company's MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in the Company's MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

## Special Note Regarding non-GAAP Financial Measures

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

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

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

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

Free cash flow is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures and dividends on common shares. The Company considers free cash flow a key measure in demonstrating the Company's ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders, and to repay debt.

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

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

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

Debt to book capitalization is a non-GAAP measure that is derived as net current and long-term debt, divided by the book value of common shareholders' equity plus net current and long-term debt. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

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

### Special Note Regarding Currency, Financial Information and Production

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

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

Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2018, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com, provided that such guidance does not form part of and is not incorporated by reference in the Company's MD&A.

## CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, November 7, 2019.

The North American conference call number is 1-866-521-4909 and the outside North American conference call number is 001-647-427-2311. Please call in 10 minutes prior to the call starting time.

An archive of the broadcast will be available until 6:00 p.m. Mountain Time, Thursday, November 21, 2019. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference archive ID number is 1387024.

The conference call will also be webcast live and can be accessed on the home page of our website at www.cnrl.com.

Canadian Natural is a senior oil and natural gas production company, with continuing operations in its core areas located in Western Canada, the U.K. portion of the North Sea and Offshore Africa.


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**STEVE W. LAUT**
Executive Vice-Chairman

**TIM S. MCKAY**
President

**MARK A. STAINTHORPE**
Chief Financial Officer and Senior Vice-President, Finance


Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange