PRESS RELEASE

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CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
2018 FOURTH QUARTER AND YEAR END RESULTS
CALGARY, ALBERTA – MARCH 7, 2019 – FOR IMMEDIATE RELEASE

Commenting on the Company's 2018 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "In 2018 we demonstrated the strength of our diverse and balanced asset base, and our ability to create value for Canadian Natural's shareholders throughout the commodity price cycle. Canadian Natural's continued focus on effective and efficient operations, ability to exercise capital flexibility and our mix of long life low decline assets resulted in cash flows from operating activities of over $10.0 billion and adjusted funds flow of over $9.0 billion in 2018, a significant achievement given industry challenges faced throughout the year."

Canadian Natural's President, Tim McKay, added, "We had a strong operational year in 2018 despite the volatility in commodity prices, as the Company was able to react quickly and strategically to changing market conditions. The Company achieved record annual production of approximately 1,079,000 BOE/d, delivering 12% production growth and 14% production per share growth over 2017 levels. Our industry leading Oil Sands Mining and Upgrading operations delivered record annual production of 426,190 bbl/d of Synthetic Crude Oil ("SCO") as a result of strong production at Horizon and a full year of production from the Athabasca Oil Sands Project. Additionally, record low annual adjusted operating costs of $21.05/bbl (US$16.24/bbl) of SCO and unadjusted operating costs of $21.75/bbl (US$16.78/bbl) of SCO were achieved as a result of safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies.

In 2018, crude oil price differentials widened due to market access restrictions and as a result, the Company made the proactive and strategic decisions throughout the year to voluntarily curtail crude oil production and reduce activity. Canadian Natural strongly supports the Government of Alberta's mandatory production curtailment program announced in late 2018 and as expected after this announcement, crude oil price differentials have since significantly narrowed. The Western Canadian Select ("WCS") differential index has narrowed to US$12.38/bbl for Q1/19 from the US$39.36/bbl experienced in Q4/18 and the differential between SCO and West Texas Intermediate ("WTI") benchmark pricing has narrowed to US $2.70/bbl for Q1/19 from the US$21.35/bbl experienced in Q4/18. As previously announced, the Company will continue to evaluate progress on export pipelines before enacting increases, if any, to its base 2019 capital budget.

Canadian Natural's mix of long life low decline assets and effective and efficient operations resulted in total Company Gross proved reserves increasing at the end of 2018 by 12% to 9.893 billion BOE, replacing 359% of 2018 production, with a reserves life index of 27.7 years. The Company's continued focus on continuous improvement, innovation and leveraging technology has lowered our overall cost structure, and as a result, proved finding, development and acquisition costs, including changes in future development capital, were excellent in 2018 and decreased from 2017 levels by 24% to $9.39/BOE."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "Throughout 2018, Canadian Natural demonstrated its financial strength and resilience to market challenges through reduced long-term debt and upgraded credit ratings. Net earnings of approximately $2.6 billion and adjusted net earnings of approximately $3.3 billion were achieved in 2018, contributing to the reduction in absolute long-term debt by approximately $1.8 billion. Free cash flow was significant in the year at approximately $2.8 billion after net capital expenditures and dividend commitments. Canadian Natural's free cash flow allocation policy that came into effect November 1, 2018 was demonstrated in 2018 as approximately 46% of annual 2018 free cash flow was allocated to share purchases and approximately 54% was allocated to the Balance Sheet, including the impact of foreign exchange, working capital and other adjustments. Returns to shareholders were significant in 2018, totaling over $2.8 billion with over $1.2 billion returned through share purchases and approximately $1.6 billion returned through dividends.

Subsequent to year end, our Board of Directors approved a quarterly dividend increase of 12% to $0.375 per share, payable on April 1, 2019. The increase marks the 19th consecutive year of dividend increases, confirming our commitment to sustainable and increasing returns to shareholders."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2018	Sep 30 2018	Dec 31 2017	Year Ended Dec 31 2018	Dec 31 2017
Net earnings (loss)	**$ (776)**	$ 1,802	$ 396	**$ 2,591**	$ 2,397
Per common share – basic	**$ (0.64)**	$ 1.48	$ 0.32	**$ 2.13**	$ 2.04
– diluted	**$ (0.64)**	$ 1.47	$ 0.32	**$ 2.12**	$ 2.03
Adjusted net earnings (loss) from operations (1)	**$ (255)**	$ 1,354	$ 565	**$ 3,263**	$ 1,403
Per common share – basic	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.68**	$ 1.19
– diluted	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.67**	$ 1.19
Cash flows from operating activities	**$ 1,397**	$ 3,642	$ 1,438	**$ 10,121**	$ 7,262
Adjusted funds flow (2)	**$ 1,229**	$ 2,830	$ 2,307	**$ 9,088**	$ 7,347
Per common share – basic	**$ 1.02**	$ 2.32	$ 1.89	**$ 7.46**	$ 6.25
– diluted	**$ 1.02**	$ 2.31	$ 1.88	**$ 7.43**	$ 6.21
Cash flows used in investing activities	**$ 1,042**	$ 1,265	$ 1,074	**$ 4,814**	$ 13,102
Net capital expenditures (3)	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129
Daily production, before royalties					
Natural gas (MMcf/d)	**1,488**	1,553	1,656	**1,548**	1,662
Crude oil and NGLs (bbl/d)	**833,358**	801,742	744,100	**820,778**	685,236
Equivalent production (BOE/d) (4)	**1,081,368**	1,060,629	1,020,094	**1,078,813**	962,264

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

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The derivation of this measure is discussed in the MD&A.

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

(4) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

ANNUAL HIGHLIGHTS

- Net earnings of $2,591 million were realized in 2018, an increase of $194 million over 2017 levels. Adjusted net earnings of $3,263 million were achieved in 2018, a $1,860 million increase over 2017 levels.
- Cash flows from operating activities were $10,121 million in 2018, an increase of $2,859 million compared to 2017 levels.
- Canadian Natural generated significant annual adjusted funds flow of $9,088 million in 2018, an increase of 24% or $1,741 million over 2017 levels. The increase year over year was primarily due to increased Synthetic Crude Oil ("SCO") production volumes, higher netbacks in the Oil Sands Mining and Upgrading segment and higher netbacks in the International segment, partially offset by lower crude oil, NGLs and natural gas netbacks in the North America Exploration and Production ("E&P") segment, and significantly lower crude oil pricing in Q4/18.
  - On December 2, 2018, the Government of Alberta announced the mandatory production curtailment program that resulted in crude oil differentials narrowing to more normalized levels. Subsequent to year end, the Western Canadian Select ("WCS") differential index narrowed to US$12.38/bbl for Q1/19 from US$39.36/bbl for Q4/18 and the differential between SCO and West Texas Intermediate ("WTI") benchmark pricing narrowed to US$2.70/bbl for Q1/19 from US$21.35/bbl for Q4/18.

- Cash flows used in investing activities were $4,814 million in 2018, a decrease of $8,288 million compared to 2017 levels as a result of acquisitions completed in 2017.
- Consistent with the Company's four pillar strategy, the Company maintained balance in the allocation of its annual adjusted funds flow throughout 2018:
  - The Company remained disciplined in its economic resource development investments with annual net capital expenditures of $4,731 million, or approximately $4,490 million, excluding net acquisitions.
  - The Company reduced long-term debt by approximately $1,835 million, including the impact of foreign exchange, working capital and other adjustments. As a result, debt to adjusted EBITDA strengthened to 2.0x and debt to book capitalization improved to 39.1%.
  - Returns to shareholders are a key focus for Canadian Natural as the Company returned a total of $2,844 million in the year, $1,562 million by way of dividends and $1,282 million by way of share purchases.
    - Share purchases for cancellation totaled 30,857,727 common shares at a weighted average share price of $41.56.
    - Subsequent to year end and up to and including March 6, 2019, the Company executed on additional share purchases of 4,340,000 common shares for cancellation at a weighted average share price of $35.86.
    - Dividends increased 22% from 2017 levels to $1.34 per share. Subsequent to year end, the Company declared a quarterly dividend increase of 12% to $0.375 per share, payable on April 1, 2019. The increase marks the 19th consecutive year that the Company has increased its dividend, reflecting the Board of Directors' confidence in Canadian Natural's sustainability and robustness of the asset base driving the ability to generate significant adjusted funds flow.
  - The Company executed on opportunistic net acquisitions of $241 million, including net exploration and evaluation proceeds of $74 million. These core area acquisitions add significant future value to the Company's long life low decline asset portfolio.
- Canadian Natural delivered annual adjusted funds flow in excess of net capital expenditures of approximately $4,360 million, including the deferred discounted purchase consideration related to the Joslyn acquisition. After dividend requirements, annual free cash flow totaled approximately $2,795 million.
  - Demonstrating Canadian Natural's commitment to balanced capital allocation, the Company allocated approximately 46% of annual 2018 free cash flow, after dividends, to share purchases and approximately 54% to the Company's Balance Sheet, including the impact of foreign exchange, working capital and other adjustments.
- The Company achieved record annual production volumes of 1,078,813 BOE/d in 2018, an increase of 12% over 2017 levels. The increase from 2017 was mainly due to a full year of Horizon Phase 3 production and a full year of production from acquisitions completed in 2017, partially offset by declines in natural gas production along with voluntary natural gas and crude oil curtailments, shut ins and reduced drilling activity.
  - Annual BOE production per share growth was strong, increasing 14% when compared to 2017 levels.
- Canadian Natural's annual corporate crude oil and NGLs production reached a record 820,778 bbl/d, an increase of 20% over 2017 levels. The increase from 2017 was mainly due to Horizon Phase 3 operating at high utilization rates and a full year of production from acquisitions completed in 2017, partially offset by voluntary crude oil production curtailments, shut ins and reduced drilling activity.
- North America crude oil and NGLs, excluding thermal in situ oil sands, averaged 243,122 bbl/d in 2018, representing a 2% increase from 2017 levels mainly due to the successful integration of acquired assets at Pelican Lake, partially offset by the impact of proactive measures taken to reduce annual drilling in the second half of the year by approximately 100 net wells, delay completion and ramp up of new wells, and voluntarily curtail crude oil production.
  - In 2018, Pelican Lake crude oil production averaged 63,082 bbl/d, a 22% increase when compared to 2017 levels primarily due to assets acquired in late 2017. In 2018, polymer flood restoration on the acquired lands was completed ahead of schedule, where approximately 62% of acquired lands are now under polymer flood.
- At the Company's world class Oil Sands Mining and Upgrading assets, industry leading operations provided record annual production of 426,190 bbl/d of SCO, an increase of 51% from 2017 levels. The increase in production was primarily due to a full year of Horizon Phase 3 operations and the acquisition of the Athabasca Oil Sands Project ("AOSP") in 2017.
  - The Company realized record low annual unadjusted operating costs of $21.75/bbl (US$16.78/bbl) of SCO in 2018, a decrease of 13% from 2017 levels. Operating costs were top tier, below the midpoint of guidance and

were achieved through safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies. After normalizing for planned turnaround downtime, operating costs decreased 10% to $21.05/bbl (US$16.24/bbl) of SCO compared to $23.40/bbl of SCO in 2017.

- In the Company's thermal in situ operations, pad additions at Primrose continue to be on budget and ahead of schedule with initial production targeted to add approximately 10,000 bbl/d in Q4/19. The program targets to add approximately 26,000 bbl/d in the first 12 months of production. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.
- At Kirby North, top tier execution and strong productivity have resulted in the project progressing two quarters ahead of the sanctioned schedule. The project now targets first steam in late Q2/19 with the flexibility to ramp up production in late Q3/19. Cost performance remains on budget with the overall project 87% complete. Kirby North's overall capacity of 40,000 bbl/d of Steam Assisted Gravity Drainage ("SAGD") production is targeted for late 2020.
- International E&P annual production volumes were strong in 2018, averaging 43,627 bbl/d, comparable to 2017 levels. International production volumes receive Brent pricing, which is not subject to the price differentials experienced in Alberta. 2018 Brent pricing averaged US$71.12/bbl, a 31% increase from 2017 pricing of US$54.38/bbl, generating significant adjusted funds flow in the Company's International segment.
  - The 2018 drilling program in the North Sea was successfully completed on time and on budget with 3.9 net producer wells drilled in the year. Current light crude oil production continues to be strong at approximately 1,250 bbl/d net per well.
  - In 2018, the Company successfully drilled 1.7 net producer wells at Baobab. Current light crude oil production is exceeding sanctioned expectations at approximately 2,500 bbl/d net per well. As a result of the successful 2018 drilling program at Baobab, Canadian Natural targets to drill one additional producer well at Baobab in 2019.
  - Subsequent to year end, the operator of the South Africa exploration well announced a discovery of significant gas condensate and targets to evaluate further exploration wells on Block 11B/12B located offshore South Africa. Canadian Natural expects the cost of the current exploration well to be fully carried. In 2019, the operator targets to acquire 3D seismic on the Block.
- Balance sheet strength and strong financial performance were demonstrated in 2018 through reduced long-term debt and upgraded credit ratings.
  - In 2018, Moody's Investors Service, Inc. upgraded the Company's senior unsecured rating to Baa2 from Baa3 and its short term rating to P-2 from P-3 with a stable outlook. Additionally, Standard & Poor's revised the Company's rating outlook to BBB+/stable from BBB+/negative.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At December 31, 2018 the Company had approximately $4,824 million of available liquidity, including cash and cash equivalents, an increase of approximately $574 million from 2017 levels.

RESERVES UPDATE

- Canadian Natural's crude oil, SCO, bitumen, natural gas and NGL reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 2018 (all reserves values are Company Gross unless stated otherwise).
  - Total proved reserves increased 12% to 9.893 billion BOE. The increase is largely driven by the addition of the Horizon South Pit, and pad additions and improved recovery at Primrose.
  - Proved developed producing reserves additions and revisions are 1.109 billion BOE, replacing 2018 production by 281%. The total proved developed producing BOE reserves life index is 21.3 years.
  - Proved reserves additions and revisions are 1.416 billion BOE, replacing 2018 production by 359%. The total proved BOE reserves life index is 27.7 years.
  - Proved plus probable reserves increased 13% to 13.382 billion BOE. Proved plus probable reserves additions and revisions are 1.910 billion BOE, replacing 2018 production by 485%. The total proved plus probable BOE reserves life index is 37.4 years.
  - Proved finding, development and acquisition ("FD&A") costs, excluding changes in future development capital ("FDC"), are $3.11/BOE and proved plus probable FD&A costs, excluding changes in FDC, are $2.31/BOE. Proved FD&A costs, including changes in FDC, are $9.39/BOE and proved plus probable FD&A costs, including changes in FDC, are $10.79/BOE.

- Proved net present value of future net revenues, before income tax, discounted at 10%, is $106.6 billion, a 19% increase from the year end 2017 evaluation. Proved plus probable net present value is $131.0 billion, a 14% increase from year end 2017.

FOURTH QUARTER HIGHLIGHTS

- Due to a significant decline in crude oil pricing, largely driven by an oversupplied domestic market environment, lack of takeaway capacity and increased global supply, the Company incurred a net loss of $776 million in Q4/18 and an adjusted net loss from operations of $255 million.
- Cash flows from operating activities were $1,397 million and adjusted funds flow were $1,229 million in Q4/18. Adjusted funds flow decreased by $1,601 million from Q3/18 levels and by $1,078 million from Q4/17 levels due to significantly wider crude oil price differentials, largely driven by market access restrictions.
- On December 2, 2018, the Government of Alberta announced the mandatory production curtailment program that resulted in crude oil differentials narrowing to more normalized levels. Subsequent to year end, the WCS differential index narrowed to US$12.38/bbl for Q1/19 from US$39.36/bbl for Q4/18 and the differential between SCO and WTI benchmark pricing narrowed to US$2.70/bbl for Q1/19 from US$21.35/bbl for Q4/18.
- The Company's production volumes in Q4/18 averaged 1,081,368 BOE/d, a 2% increase over Q3/18 levels and a 6% increase over Q4/17 levels. The increase from the comparable quarters was mainly due to strong production from the Oil Sands Mining and Upgrading segment partially offset by reduced drilling activity and the impact of strategic actions taken to voluntarily curtail primary heavy and thermal in situ crude oil production totalling approximately 24,500 bbl/d.
- At the Company's world class Oil Sands Mining and Upgrading assets, top tier operations provided quarterly production of 447,048 bbl/d of SCO, an increase of 39% over Q4/17 levels mainly due to production from the Horizon Phase 3 expansion and a 13% increase over Q3/18 levels as operations resumed following a major planned turnaround at Horizon.
  - The Company realized industry leading operating costs of $19.97/bbl (US$15.12/bbl) of SCO in Q4/18, through safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies. These results were comparable to Q3/18 levels and a 20% decrease from Q4/17 levels.
- Offshore Africa quarterly production volumes averaged 22,185 bbl/d in Q4/18, an 18% increase over Q3/18 and a 14% increase over Q4/17 levels. The increase in production from the comparable periods was primarily due to production from new wells drilled at Baobab in 2018, partially offset by natural field declines. International production receives Brent pricing that averaged US$67.45/bbl in Q4/18, a 10% increase from Q4/17 pricing of US$61.46/bbl, generating significant adjusted funds flow in the Company's international segment.
- Share purchases for cancellation in the quarter totaled 10,845,600 common shares at a weighted average share price of $37.67.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK section of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light crude oil, medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen 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 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

	Year Ended Dec 31			
	2018		2017	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**513**	**483**	529	495
Natural gas	**25**	**18**	27	21
Dry	**9**	**9**	7	7
Subtotal	**547**	**510**	563	523
Stratigraphic test / service wells	**717**	**615**	289	289
Total	**1,264**	**1,125**	852	812
Success rate (excluding stratigraphic test / service wells)		**98%**		99%

- The Company's total crude oil and natural gas drilling program of 510 net wells for the year ended December 31, 2018, excluding strat/service wells, was a decrease of 13 net wells from the same period in 2017. The Company's drilling levels reflect 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			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs production (bbl/d)	**240,942**	247,314	259,416	**243,122**	239,309
Net wells targeting crude oil	**62**	140	123	**361**	472
Net successful wells drilled	**61**	135	120	**353**	466
Success rate	**98%**	96%	98%	**98%**	99%

- North America crude oil and NGLs averaged 243,122 bbl/d in 2018, representing a 2% increase from 2017 levels mainly due to the successful integration of acquired assets at Pelican Lake, partially offset by the impact of proactive measures taken to reduce annual drilling in the second half of the year by approximately 100 net wells, delay completion and ramp up of new wells, and voluntarily curtail crude oil production.
- Canadian Natural's primary heavy crude oil production averaged 86,312 bbl/d in 2018, a 10% decrease from 2017 levels primarily due to strategic actions taken to reduce drilling, delay completion and ramp of new wells and voluntarily curtail primary heavy crude oil production due to widening price differentials driven by market access restrictions.
  - In the second half of 2018, to maximize value as a result of widening price differentials, Canadian Natural implemented proactive and strategic decisions to reallocate capital from primary heavy crude oil assets to light crude oil assets. As a result, the Company drilled 137 fewer net primary heavy crude oil wells and delayed completion on 29 net wells in the year, compared to the original budget.
  - At the Company's Smith primary heavy crude oil play, production from 6 net multilateral wells drilled in 2018 continues to exceed sanctioned expectations with current rates of approximately 300 bbl/d per well and lower than expected decline rates. There is significant development potential at Smith for approximately 118 net horizontal multilateral wells on the Company's 19 net sections and the Company targets to evaluate the future development opportunities at Smith as market access improves.
  - Operating costs of $16.60/bbl were achieved in the Company's primary heavy crude oil operations in 2018, a 6% increase from 2017 levels, strong results given lower production volumes due to the Company's decision to curtail production.
- North America light crude oil and NGL production averaged 93,728 bbl/d in 2018, an increase of 2% from 2017 levels. The increase from 2017 is primarily as a result of reallocation of capital from primary heavy crude oil to light crude oil drilling projects.
  - The Company successfully drilled 99 net light crude oil wells in 2018, 32 net wells above budget as the Company reallocated capital from primary heavy crude oil to light crude oil in the second half of 2018. Production from the additional light crude oil wells came on in late Q4/18 and in early Q1/19. Highlights from the drilling program are as follows:
    - Within the greater Wembley area, results continue to exceed expectations. The Company drilled 27 net wells in 2018, 14 of which came on production with initial 30 day liquids production rates averaging approximately 600 bbl/d per well. The remaining wells are targeted to come on production in Q1/19. Within the greater Wembley area, the Company has identified 155 net Montney sections and 365 incremental potential premium light crude oil and liquids rich well locations.
      - The Company's core Wembley light crude oil play, included within the greater Wembley area identified above, has 88 net sections of land and 213 potential premium well locations. In the core Wembley light crude oil area, production results have been strong as the Company completed 12 net wells in 2018, 7 of which came on production late in the year with initial 30 day liquids production rates averaging approximately 785 bbl/d per well. The remaining 5 wells are targeted to come on production in Q1/19.
    - In Southeast Saskatchewan and Manitoba, the Company drilled 33 net light crude oil wells in 2018, an additional 18 wells than budgeted as a result of the strategic decision to shift capital to light crude oil assets. Currently, production from these wells is averaging 2,750 bbl/d, in-line with expectations. Production from these Saskatchewan and Manitoba wells are less impacted by the price differentials experienced in Alberta.
  - In 2018, operating costs of $15.29/bbl were realized in the Company's North America light crude oil and NGL areas.
- Pelican Lake annual production averaged 63,082 bbl/d, an increase of 22% from 2017 levels, primarily as a result of the Company's successful integration of acquired assets in late 2017. Canadian Natural's long life low decline Pelican Lake assets along with the Company's industry leading polymer flood technology are driving significant value.
  - Polymer flood restoration in 2018 on the acquired lands was completed ahead of schedule, where approximately 62% of acquired lands are now under polymer flood.
  - In Q4/18, the Company drilled 4 net strategic wells with initial production results of approximately 100 bbl/d per well, exceeding sanctioned expectations. The Company has identified potential opportunities for an additional 31 producer wells.
  - Facility consolidation is targeted to be complete in early Q2/19, resulting in targeted operating cost savings of approximately $6 million per year.

- Strong operating costs of $6.72/bbl were achieved in 2018 at Pelican Lake.

- The Company's 2019 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range between 221,000 bbl/d - 241,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Bitumen production (bbl/d)	**102,112**	112,542	124,121	**107,839**	120,140
Net wells targeting bitumen	**41**	41	5	**125**	27
Net successful wells drilled	**40**	41	5	**124**	27
Success rate	**98%**	100%	100%	**99%**	100%

- Thermal in situ annual production volumes averaged 107,839 bbl/d in 2018, a 10% decrease from 2017 levels, primarily due to proactive and strategic decisions to voluntarily curtail production volumes of approximately 4,200 bbl/d.
  - At Primrose, 2018 production volumes averaged approximately 70,000 bbl/d, a decrease of 14% from 2017 levels, primarily as a result of proactive and strategic decisions to voluntarily curtail production volumes and the cyclical nature of thermal production. Including energy costs, operating costs were $14.03/bbl in 2018, an increase of 14% from 2017 levels, reflecting lower volumes due to voluntary curtailment and increased carbon tax and energy costs in 2018.
    - Pad additions at Primrose continue to be on budget and ahead of schedule with initial production targeted to add approximately 10,000 bbl/d in Q4/19. The program targets to add approximately 26,000 bbl/d in the first 12 months of production. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.
  - At Kirby South, SAGD production volumes of 35,061 bbl/d were achieved in 2018, a 3% decrease from 2017 levels. Including energy costs, Kirby South achieved strong 2018 annual operating costs of $9.54/bbl, comparable to $9.50/bbl in 2017.
  - At Kirby North, top tier execution and strong productivity have resulted in the project progressing two quarters ahead of the sanctioned schedule. The project now targets first steam in late Q2/19 with the flexibility to ramp up production in late Q3/19. Cost performance remains on budget with the overall project 87% complete. Kirby North's overall capacity of 40,000 bbl/d of SAGD production is targeted for late 2020.
- The Company's 2019 thermal in situ annual production guidance remains unchanged and is targeted to range between 104,000 bbl/d - 124,000 bbl/d.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Natural gas production (MMcf/d)	**1,441**	1,489	1,596	**1,490**	1,601
Net wells targeting natural gas	**3**	6	2	**18**	22
Net successful wells drilled	**3**	6	2	**18**	21
Success rate	**100%**	100%	100%	**100%**	95%

- North America natural gas production was 1,490 MMcf/d in 2018, a decrease of 7% from 2017 levels, primarily due to strategic decisions to reduce drilling and development activities, curtail and shut in production as a result of low natural gas prices, reduced production rates at the Pine River plant, operated by a third party, and natural field declines.

- Deferred capital and development activity, including recompletions and workovers of certain natural gas assets, along with production shut ins resulted in a production impact of approximately 79 MMcf/d in 2018.
- Additionally, the Company's natural gas production capability was reduced by approximately 48 MMcf/d in 2018 due to restrictions at the Pine River plant, operated by a third party.

▪ The Pine River plant, operated by a third party, is currently operating at restricted rates of approximately 90 MMcf/d. As previously announced, Canadian Natural agreed to acquire the facility from the third party and is awaiting regulatory approval. The Company completed an engineering cost assessment of the plant and has determined the optimal plant capacity to be 120 MMcf/d compared to the previous estimate of 145 MMcf/d and targets to complete the work in Q3/19.

▪ Operating costs of $1.25/Mcf were realized in 2018, an increase of 5% from 2017 levels, strong results given lower natural gas production volumes.

▪ The Company's natural gas reinjection pilot at Septimus has received regulatory approval and is targeted to commence with first injection of 5 MMcf/d in late Q2/19. If successful, natural gas reinjection has the potential to add significant value by unlocking liquids rich development without producing incremental natural gas in a constrained takeaway environment.

▪ In 2018, Canadian Natural used the equivalent of approximately 35% of its total corporate natural gas production in its operations, providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 32% of the Company's total 2018 natural gas production was exported to other North American markets and sold internationally at an average price of $4.32/Mcf. The remaining 33% of the Company's 2018 natural gas production was exposed to AECO/Station 2 pricing.

▪ The Company's 2019 corporate natural gas annual 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			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil production (bbl/d)					
North Sea	**21,071**	28,702	19,548	**23,965**	23,426
Offshore Africa	**22,185**	18,802	19,519	**19,662**	20,335
Natural gas production (MMcf/d)					
North Sea	**22**	38	37	**32**	39
Offshore Africa	**25**	26	23	**26**	22
Net wells targeting crude oil	**1.1**	1.6	—	**5.6**	1.8
Net successful wells drilled	**1.1**	1.6	—	**5.6**	1.8
Success rate	**100%**	100%	—	**100%**	100%

▪ International E&P annual production volumes were strong in 2018, averaging 43,627 bbl/d, comparable to 2017 levels. International production volumes receive Brent pricing, which is not subject to the price differentials experienced in Alberta. 2018 Brent pricing averaged US$71.12/bbl, a 31% increase from 2017 pricing of US$54.38/bbl, generating significant adjusted funds flow in the Company's international segment.

- In the North Sea, production volumes of 23,965 bbl/d were achieved in 2018, an increase of 2% over 2017 levels, primarily due to the successful 2018 drilling program, partially offset by natural field declines.
  - The 2018 drilling program in the North Sea was successfully completed on time and on budget with 3.9 net producer wells drilled in the year. Current light crude oil production is as expected at approximately 1,250 bbl/d net per well.
  - The 2019 drilling program of 3.9 net producer wells in the North Sea commenced in Q1/19 at the Ninian South Platform.

- Annual operating costs in the North Sea averaged $39.89/bbl (£23.06/bbl), within annual corporate guidance, as the Company continues to focus on production enhancements, increased reliability and water flood optimization.

- Offshore Africa production volumes in 2018 averaged 19,662 bbl/d, a decrease of 3% from 2017 levels, primarily as a result of natural field declines, partially offset by increased production in Q4/18 from a successful drilling program at Baobab.
  - Côte d'Ivoire crude oil operating costs in 2018 were $13.30/bbl (US$10.26/bbl), a 7% increase from 2017 mainly due to timing of liftings from Espoir and Baobab that have different cost structures, fluctuating production volumes on a relatively fixed cost base, planned maintenance activities and fluctuations in foreign exchange rates.
  - In 2018, the Company successfully drilled 1.7 net producer wells at Baobab. Current light crude oil production is exceeding sanctioned expectations at approximately 2,500 bbl/d net per well. As a result of the successful 2018 drilling program at Baobab, Canadian Natural targets to drill one additional producer well at Baobab in 2019.
  - In 2019, the Company targets to drill an appraisal well at Kossipo, and if successful will lead to development drilling and a pipeline tied-back to the Baobab Floating Production Storage and Offloading ("FPSO") vessel, adding significant future value with potential gross production capability of 20,000 bbl/d targeted in 2022.
  - At Espoir, the Company targets to commence the Phase 4 development in Q4/19 with initial production targeted for early 2020.
  - In Q4/18, the Gabonese Republic approved cessation of production from the Company’s Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic.
    - In late Q4/18, the Olowi field was shut in. Subsequent to year end, well suspensions were completed and the Olowi FPSO was off location in early Q1/19.
  - In Q4/18, the Company farmed out a further 5% working interest in the Exploration Right relating to Block 11B/12B located offshore South Africa. Canadian Natural's working interest in the Block is now 20%.
    - As a result of the farm out agreements, Canadian Natural received up front cash consideration and a financial carry on the exploration well costs and subsequent operations. Subject to there being a commercial discovery, the Company will receive further bonus payments.
    - Subsequent to year end, the operator of the South Africa exploration well announced a discovery of significant gas condensate and targets to evaluate further exploration wells on the Block. Canadian Natural expects the cost of the current exploration well to be fully carried. In 2019, the operator targets to acquire 3D seismic on the Block.

- The Company's 2019 International annual production guidance remains unchanged and is targeted to range from 42,000 bbl/d - 46,000 bbl/d.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Synthetic crude oil production (bbl/d) (1) (2)	**447,048**	394,382	321,496	**426,190**	282,026

(1) Q4/18 SCO production before royalties excludes 3,363 bbl/d of SCO consumed internally as diesel (Q3/18 – 2,758 bbl/d; Q4/17 – 1,730 bbl/d; 2018 – 3,093 bbl/d; 2017 – 651 bbl/d).

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

- At the Company's world class Oil Sands Mining and Upgrading assets, top tier operations provided record annual production of 426,190 bbl/d of SCO, an increase of 51% from 2017 levels. The increase in production was primarily due to a full year of Horizon Phase 3 operations and the acquisition of the AOSP in 2017.
  - The Company realized record low annual unadjusted operating costs of $21.75/bbl (US$16.78/bbl) of SCO in 2018, a decrease of 13% from 2017 levels. Operating costs were top tier, below the midpoint of guidance and were achieved through safe, steady and reliable operations, high utilization, and leveraging expertise to capture

synergies. After normalizing for planned turnaround downtime, operating costs decreased 10% to $21.05/bbl (US$16.24/bbl) of SCO compared to $23.40/bbl of SCO in 2017.

- The Company continues to progress engineering work on the previously announced potential expansion and reliability opportunities at Horizon to increase reliability and lower costs, targeting to add production of 75,000 bbl/d to 95,000 bbl/d. The engineering and design specification work is targeted to be complete in Q1/19. The remainder of the year will target to focus on key procurement and detailed engineering.
  - The potential Paraffinic Froth Treatment expansion at Horizon is targeting 40,000 bbl/d to 50,000 bbl/d of high quality diluted bitumen at significantly lower operating costs as the Company leverages its existing infrastructure. The preliminary estimate of the capital required is approximately $1.4 billion.
  - Stage 1 and 2 reliability opportunities at Horizon are targeted to add near-term growth of 35,000 bbl/d to 45,000 bbl/d of SCO.
  - The Company targets to sanction the potential expansion and reliability opportunities with greater clarity on improved market access.
- As a result of Canadian Natural's continued focus on execution excellence and the Government of Alberta's mandated production curtailments, the Company has optimized planned maintenance timing within the Oil Sands Mining and Upgrading operations, as follows:
  - Canadian Natural has accelerated the timing of planned pit stop maintenance activities at Horizon to March 2019 from April 2019, optimizing production levels throughout the Company's assets. The planned maintenance is targeted for 12 days on the Vacuum Distillate and Diluent Recovery Unit furnaces at which time the Upgrader will run at restricted rates of approximately 140,000 bbl/d of SCO. Additional planned turnaround activities at Horizon are targeted for the fall of 2019.
  - The planned 38 day turnaround at the Scotford Upgrader is targeted for April and May 2019, at which time the Upgrader will run at restricted net rates of approximately 162,000 bbl/d of SCO. At AOSP, additional planned pit stop activities are targeted for the fall of 2019.
- The Company's 2019 Oil Sands Mining and Upgrading annual production guidance remains unchanged and is targeted to range between 415,000 bbl/d - 450,000 bbl/d of SCO.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 58.83**	$ 69.50	$ 55.39	**$ 64.78**	$ 50.93
WCS heavy differential as a percentage of WTI (%) [2]	**67%**	32%	22%	**41%**	23%
SCO price (US$/bbl)	**$ 37.48**	$ 68.44	$ 58.64	**$ 58.62**	$ 52.20
Condensate benchmark pricing (US$/bbl)	**$ 45.27**	$ 66.82	$ 57.96	**$ 60.98**	$ 51.65
Average realized pricing before risk management (C$/bbl) [3]	**$ 25.95**	$ 57.89	$ 53.42	**$ 46.92**	$ 48.57
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.80**	$ 1.28	$ 1.85	**$ 1.45**	$ 2.30
Average realized pricing before risk management (C$/Mcf)	**$ 3.46**	$ 2.32	$ 2.55	**$ 2.61**	$ 2.76

(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 Q4/18 there was a significant decline in crude oil pricing as a result of increased global supply, an oversupplied domestic market and a lack of takeaway capacity, resulting in increased storage levels in Q4/18, impacting pricing as follows:
  - WTI prices decreased 15% in Q4/18 from Q3/18 levels, reflecting increased global supply.

- The WCS heavy differential widened by 78% to US$39.36/bbl for Q4/18 from US$22.17/bbl for Q3/18. Following the Government of Alberta's announcement of a mandatory curtailment of crude oil production on December 2, 2018, the WCS differential index narrowed to US$12.38/bbl for Q1/19 from US$39.36/bbl for Q4/18.
- SCO prices in Q4/18 decreased 45% when compared to Q3/18 levels. Following the Government of Alberta's announcement of a mandatory curtailment of crude oil production on December 2, 2018, the differential between SCO and WTI benchmark pricing narrowed to US$2.70/bbl for Q1/19 from US$21.35/bbl for Q4/18.
- Condensate pricing in Q4/18 decreased when compared to Q4/17 and Q3/18 due to increased condensate supply, incremental blending of light crude oil into condensate and decreased demand due to curtailment of crude oil production in the basin.

▪ AECO natural gas prices increased in Q4/18 from Q3/18 and from Q2/18 levels reflecting the easing of third party pipeline constraints as well as seasonal demand factors. AECO natural gas prices decreased from 2017 levels, reflecting third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the basin.

▪ 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 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

▪ Canadian Natural has invested over $3.1 billion in research and development since 2009 and continues to invest in technology to unlock reserves, become more effective and efficient, increase production and reduce the Company's environmental footprint. Canadian Natural's culture of continuous improvement leverages the use of technology and innovation to drive sustainable operations and long-term value for shareholders.

▪ Canadian Natural has invested significant capital to capture and sequester CO_2. The Company has carbon capture and sequestration facilities at Horizon, a 70% working interest in the Quest Carbon Capture and Storage project at Scotford and carbon capture facilities at its 50% interest through the NWR refinery. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of CO_2 annually, equivalent to taking 576,000 vehicles off the road per year, making the Company the 3rd largest CO_2 capturer and sequester for the oil and gas sector globally once the NWR refinery is fully running.

▪ At Canadian Natural's Oil Sands Mining and Upgrading and thermal in situ operations, which represent approximately 65% 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, including carbon capture initiatives, Canadian Natural has developed a pathway to reduce the Company's greenhouse gas emissions intensity to 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 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. As a result of the positive results thus far, the Company continues to make enhancements and will operate and test the pilot through 2019.

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 1,078,813 BOE/d in 2018, 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 52% light crude oil and SCO blends, 24% heavy crude oil blends and 24% natural gas, based upon annual 2018 production.
  - Canadian Natural's production is resilient, as long life low decline assets make up approximately 73% of 2018 annual liquids production, including the Oil Sands Mining and Upgrading, Pelican Lake and thermal in situ oil sands assets.
- In 2018, Canadian Natural delivered adjusted funds flow in excess of net capital expenditures of approximately $4,360 million, including deferred discounted purchase consideration. After dividend requirements, free cash flow totaled approximately $2,795 million in the year.
- Balance sheet strength and strong financial performance were demonstrated in 2018 through reduced long-term debt and upgraded credit ratings.
  - Canadian Natural settled the deferred AOSP acquisition liability totaling $481 million and reduced long-term debt by approximately $1,835 million, including the impact of foreign exchange, compared to 2017 levels.
  - In 2018, Moody's Investors Service, Inc. upgraded the Company's senior unsecured rating to Baa2 from Baa3 and its short term rating to P-2 from P-3 with a stable outlook. Additionally, Standard & Poor's revised the Company's rating outlook to BBB+/stable from BBB+/negative.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At December 31, 2018 the Company had approximately $4,824 million of available liquidity, including cash and cash equivalents, an increase of approximately $574 million from 2017 levels.
  - As at December 31, 2018, debt to book capitalization improved to 39.1% from 41.4% in 2017 and debt to adjusted EBITDA strengthened to 2.0x from 2.7x in 2017.
- Returns to shareholders are a key focus for Canadian Natural as the Company returned a total of $2,844 million in the year, $1,562 million by way of dividends and $1,282 million by way of share purchases.
  - In the quarter, share purchases for cancellation totaled 10,845,000 common shares at a weighted average share price of $37.67.
  - In 2018, share purchases for cancellation totaled 30,857,727 common shares at a weighted average share price of $41.56.
  - Subsequent to year end and up to and including March 6, 2019, the Company executed on additional share purchases of 4,340,000 common shares for cancellation at a weighted average share price of $35.86.
- 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 new policy, the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures and dividends, 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. At present, this policy is expected to be in place until at least the Company's NCIB renewal in May 2019, subject to quarterly review by the Board of Directors. This policy was effective November 1, 2018.
- In addition to its 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 December 31, 2018, these financial levers include the Company's third party equity investments of approximately $524 million, and cross currency swaps and foreign currency forward contracts with a total value of $361 million.

- Subsequent to year end, Canadian Natural increased its quarterly dividend by 12% to $0.375 per share payable on April 1, 2019. The increase marks the 19th consecutive year that the Company has increased its dividend, reflecting the Board of Director's confidence in Canadian Natural's sustainability and robustness of the asset base driving the ability to generate significant adjusted funds flow.

CORPORATE UPDATE

- The Board of Directors approved the previously announced leadership changes. The changes summarized below will be effective March 29, 2019.
  - Corey B. Bieber, Senior Vice-President Finance and Chief Financial Officer will become Executive Advisor.
  - Mark Stainthorpe, Vice President – Capital Markets, will assume the role of Chief Financial Officer and Senior Vice President, Finance and will join the Management Committee.
  - Ron Kim, Vice President, Finance – Corporate will assume the role of Principal Accounting Officer and Vice President, Finance, reporting to Mark Stainthorpe.

OUTLOOK

The Company targets annual 2019 production levels to average between 782,000 and 861,000 bbl/d of crude oil and NGLs and between 1,485 and 1,545 MMcf/d of natural gas, before royalties. Q1/19 production guidance before royalties is targeted to average between 759,000 and 817,000 bbl/d of crude oil and NGLs and between 1,490 and 1,520 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

Canadian Natural's annual 2019 capital expenditures are targeted to be approximately $3.7 billion.

2018 YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2018, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Limited, to evaluate and review all of the Company's proved and proved plus probable reserves. The IQREs conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves. All reserves values are Company Gross unless stated otherwise.

Corporate Total

- Canadian Natural's 2018 performance has resulted in another year of excellent finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding changes in Future Development Capital ("FDC"), are $3.11/BOE for proved reserves and $2.31/BOE for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $9.39/BOE for proved reserves and $10.79/BOE for proved plus probable reserves.
- Proved reserves additions and revisions replaced 2018 production by 359%. Proved plus probable reserves additions and revisions replaced 2018 production by 485%.
- Proved reserves increased 12% to 9.893 billion BOE with reserves additions and revisions of 1.416 billion BOE. Proved plus probable reserves increased 13% to 13.382 billion BOE with reserves additions and revisions of 1.910 billion BOE.
- The proved BOE reserves life index is 27.7 years and the proved plus probable BOE reserves life index is 37.4 years.
- Proved developed producing reserves additions and revisions are 1.109 billion BOE, replacing 2018 production by 281%. The total proved developed producing BOE reserves life index is 21.3 years.
- Recycle ratios are 8.7 times and 11.8 times for proved and proved plus probable reserves respectively, excluding changes in FDC, recycle ratios are 2.9 times and 2.5 times for proved and proved plus probable reserves respectively, including changes in FDC.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 19% to $106.6 billion for proved reserves and increased 14% to $131.0 billion for proved plus probable reserves. The net present value for proved developed producing reserves increased 24% to $84.2 billion reflecting the impact of the Horizon South Pit addition and decreased operating costs at AOSP.

North America Exploration and Production

- Canadian Natural's North America conventional and thermal assets delivered strong reserves results in 2018:
  - FD&A costs, excluding changes in FDC, are $6.51/BOE for proved reserves and $3.50/BOE for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $7.23/BOE for proved reserves and $10.54/BOE for proved plus probable reserves.
- Proved reserves additions and revisions replaced 187% of 2018 production. Proved plus probable reserves additions and revisions replaced 349% of 2018 production.
- Proved reserves increased 6% to 3.588 billion BOE. This is comprised of 2.488 billion bbl of crude oil, bitumen, and NGL reserves and 6.597 Tcf of natural gas reserves.
- Proved plus probable reserves increased 10% to 6.027 billion BOE. This is comprised of 4.421 billion bbl of crude oil, bitumen, and NGL reserves and 9.633 Tcf of natural gas reserves.
- Proved reserves additions and revisions are 341 million bbl of crude oil, bitumen and NGL and 411 Bcf of natural gas. Proved plus probable reserves additions and revisions are 654 million bbl of crude oil, bitumen and NGL and 657 Bcf of natural gas.
- The proved BOE reserves life index is 18.9 years and the proved plus probable BOE reserves life index is 31.7 years.

North America Oil Sands Mining and Upgrading

- Canadian Natural's Oil Sands Mining and Upgrading segment delivered strong reserves results in 2018:
  - FD&A costs, excluding changes in FDC, are $1.47/bbl for proved reserves and $1.29/bbl for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $10.49/bbl for proved reserves and $11.33/bbl for proved plus probable reserves.
- Proved SCO reserves increased 16% to 6.091 billion bbl. Proved plus probable SCO reserves increased 16% to 7.032 billion bbl.
- SCO reserves account for 62% of the Company's proved BOE reserves and 53% of the proved plus probable BOE reserves.

International Exploration and Production

- North Sea proved reserves are unchanged at 124 million BOE and proved plus probable reserves increased 4% to 193 million BOE.
- Offshore Africa proved reserves increased 5% to 90 million BOE and proved plus probable reserves decreased 4% to 131 million BOE.

2018 FD&A Costs excluding changes in FDC (10)	Proved ($/BOE)	Proved plus Probable ($/BOE)
North America E&P	$6.51	$3.50
Oil Sands Mining and Upgrading	$1.47	$1.29
Total Canadian Natural	$3.11	$2.31

2018 FD&A Costs including changes in FDC (11)	Proved ($/BOE)	Proved plus Probable ($/BOE)
North America E&P	$7.23	$10.54
Oil Sands Mining and Upgrading	$10.49	$11.33
Total Canadian Natural	$9.39	$10.79

Corporate Total

2018 Reserves Replacement (8)	% of 2018 Production Replaced
Proved Developed Producing	281%
Proved	359%
Proved plus Probable	485%

Company Gross Reserves	2017 (MMBOE)	2018 (MMBOE)	Increase
Proved Developed Producing	6,908	7,623	10%
Proved	8,871	9,893	12%
Proved plus Probable	11,866	13,382	13%

2018 Recycle Ratios (12)	Excluding changes in FDC	Including changes in FDC
Proved	8.7x	2.9x
Proved plus Probable	11.8x	2.5x

Net Present Value of Future Net Revenues, before income tax, discounted at 10% (13)	2017 ($ billion)	2018 ($ billion)	Increase
Proved Developed Producing	68.1	84.2	24%
Proved	89.8	106.6	19%
Proved plus Probable	114.5	131.0	14%

Summary of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	114	97	248	311	6,091	3,477	101	7,541
Developed Non-Producing	14	16	—	123	—	326	10	218
Undeveloped	66	69	57	1,106	—	2,794	156	1,920
Total Proved	194	182	305	1,540	6,091	6,597	267	9,679
Probable	74	70	140	1,519	941	3,036	130	3,379
Total Proved plus Probable	268	252	445	3,059	7,032	9,633	397	13,058
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	41					17		44
Developed Non-Producing	—					—		—
Undeveloped	45					11		46
Total Proved	86					28		90
Probable	35					35		41
Total Proved plus Probable	121					63		131
Total Company								
Proved								
Developed Producing	189	97	248	311	6,091	3,517	101	7,623
Developed Non-Producing	18	16	—	123	—	326	10	222
Undeveloped	192	69	57	1,106	—	2,809	156	2,048
Total Proved	399	182	305	1,540	6,091	6,652	267	9,893
Probable	176	70	140	1,519	941	3,082	130	3,489
Total Proved plus Probable	575	252	445	3,059	7,032	9,734	397	13,382

Summary of Company Net Reserves

As of December 31, 2018
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	101	81	189	252	5,125	3,183	80	6,358
Developed Non-Producing	12	14	—	104	—	303	8	189
Undeveloped	56	59	48	911	(8)	2,519	131	1,616
Total Proved	169	154	237	1,267	5,117	6,005	219	8,163
Probable	61	57	100	1,210	761	2,676	104	2,740
Total Proved plus Probable	230	211	337	2,477	5,878	8,681	323	10,903
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	36					12		38
Developed Non-Producing	—					—		—
Undeveloped	36					9		38
Total Proved	72					21		76
Probable	26					23		30
Total Proved plus Probable	98					44		106
Total Company								
Proved								
Developed Producing	171	81	189	252	5,125	3,218	80	6,434
Developed Non-Producing	16	14	—	104	—	303	8	193
Undeveloped	173	59	48	911	(8)	2,532	131	1,736
Total Proved	360	154	237	1,267	5,117	6,053	219	8,363
Probable	154	57	100	1,210	761	2,710	104	2,839
Total Proved plus Probable	514	211	337	2,477	5,878	8,763	323	11,202

Reconciliation of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	171	198	327	1,350	5,264	6,730	229	8,661
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	17	6	—	4	—	470	38	143
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	3	2	—	—	—	82	4	22
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	—	1	1	—	—	(305)	(4)	(53)
Technical Revisions	10	(2)	(1)	52	175	42	6	247
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	**194**	**182**	**305**	**1,540**	**6,091**	**6,597**	**267**	**9,679**

North Sea	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	120					21		124
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	8					—		8
Dispositions	—					—		—
Economic Factors	5					—		5
Technical Revisions	(6)					18		(3)
Production	(9)					(12)		(11)
December 31, 2018	**119**					**27**		**124**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	83					20		86
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	10					17		13
Production	(7)					(9)		(9)
December 31, 2018	**86**					**28**		**90**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	18	6	—	4	—	470	38	144
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	11	2	—	—	—	82	4	30
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	5	1	1	—	—	(305)	(4)	(48)
Technical Revisions	14	(2)	(1)	52	175	77	6	257
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**399**	**182**	**305**	**1,540**	**6,091**	**6,652**	**267**	**9,893**

Reconciliation of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	68	74	142	1,230	799	2,790	106	2,884
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	1	1	—	403	—	22	1	410
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(1)	—	—	—	—	(104)	(1)	(19)
Technical Revisions	(5)	(13)	(4)	(176)	71	(155)	(3)	(157)
Production	—	—	—	—	—	—	—	—
December 31, 2018	**74**	**70**	**140**	**1,519**	**941**	**3,036**	**130**	**3,379**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	60	11	61
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	5	—	5
Dispositions	—	—	—
Economic Factors	(5)	—	(5)
Technical Revisions	7	—	8
Production	—	—	—
December 31, 2018	**67**	**11**	**69**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	42	47	50
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	(7)	(12)	(9)
Production	—	—	—
December 31, 2018	**35**	**35**	**41**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	170	74	142	1,230	799	2,848	106	2,995
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	6	1	—	403	—	22	1	415
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(6)	—	—	—	—	(104)	(1)	(24)
Technical Revisions	(5)	(13)	(4)	(176)	71	(167)	(3)	(158)
Production	—	—	—	—	—	—	—	—
December 31, 2018	**176**	**70**	**140**	**1,519**	**941**	**3,082**	**130**	**3,489**

Reconciliation of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	239	272	469	2,580	6,063	9,520	335	11,545
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	23	8	—	5	—	861	60	240
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	4	3	—	403	—	104	5	432
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	5	(15)	(5)	(124)	246	(113)	3	90
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	**268**	**252**	**445**	**3,059**	**7,032**	**9,633**	**397**	**13,058**

North Sea

December 31, 2017	180					32		185
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	13					—		13
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	1					18		5
Production	(9)					(12)		(11)
December 31, 2018	**186**					**38**		**193**

Offshore Africa

December 31, 2017	125					67		136
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	3					5		4
Production	(7)					(9)		(9)
December 31, 2018	**121**					**63**		**131**

Total Company

December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	24	8	—	5	—	861	60	241
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	17	3	—	403	—	104	5	445
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	9	(15)	(5)	(124)	246	(90)	3	99
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**575**	**252**	**445**	**3,059**	**7,032**	**9,734**	**397**	**13,382**

Reserves Notes:

(1) *Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.*

(2) *Company Net reserves are working interest share after deduction of royalties and including any royalty interests.*

(3) *BOE values may not calculate due to rounding.*

(4) *Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates were provided by Sproule Associates Limited:*

	2019	2020	2021	2022	2023	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 63.00	$ 67.00	$ 70.00	$ 71.40	$ 72.83	2.00%
Western Canada Select (C$/bbl)	$ 59.47	$ 62.31	$ 67.45	$ 69.53	$ 71.66	2.00%
Canadian Light Sweet (C$/bbl)	$ 75.27	$ 77.89	$ 82.25	$ 84.79	$ 87.39	2.00%
Cromer LSB (C$/bbl)	$ 75.27	$ 76.89	$ 81.25	$ 83.79	$ 86.39	2.00%
Edmonton Pentanes+ (C$/bbl)	$ 75.32	$ 80.00	$ 83.75	$ 85.50	$ 87.29	2.00%
North Sea Brent (US$/bbl)	$ 70.00	$ 72.00	$ 73.00	$ 74.46	$ 75.95	2.00%
Natural gas						
AECO (C$/MMBtu)	$ 1.95	$ 2.44	$ 3.00	$ 3.21	$ 3.30	2.00%
BC Westcoast Station 2 (C$/MMBtu)	$ 1.35	$ 1.94	$ 2.60	$ 2.81	$ 2.90	2.00%
Henry Hub (US$/MMBtu)	$ 3.00	$ 3.25	$ 3.50	$ 3.57	$ 3.64	2.00%

Note: A foreign exchange rate of 0.7700 US$/C$ for 2019 and 0.8000 US$/C$ after 2019 was used in the 2018 evaluation.

(5) *A barrel of oil equivalent (“BOE”) is derived by converting six thousand cubic feet of natural gas to one barrel 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.*

(6) *Metrics included herein are commonly used in the oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural’s performance over time. However, such measures are not reliable indicators of Canadian Natural’s future performance and future performance may vary.*

(7) *Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.*

(8) *Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.*

(9) *Reserves Life Index is based on the amount for the relevant reserves category divided by the 2019 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.*

(10) *Finding, Development and Acquisition ("FD&A") costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2018 by the sum of total additions and revisions for the relevant reserves category. All values used in the calculation are not rounded.*

(11) *FD&A costs including changes in Future Development Capital ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2018 and net changes in FDC from December 31, 2017 to December 31, 2018 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment and reclamation costs. All values used in the calculation are not rounded.*

(12) *Recycle Ratio is the operating netback ($27.13/BOE for 2018) divided by the FD&A (in $/BOE). Operating netback is production revenues, excluding realized gains and losses on commodity hedging, less royalties, transportation and production expenses, calculated on a per BOE basis.*

(13) *Abandonment and reclamation costs included in the calculation of the Future Net Revenue (FNR) for 2018 consist of both forecast estimates of abandonment and reclamation costs attributable to future development activity, as well as certain costs already included in the Company’s Asset Retirement Obligation (ARO) for development existing as at December 31, 2018. The portion of the Company’s estimated ARO included in the reserves FNR is escalated at 2.0% per year after 2019. Specifically, for North America (excluding SCO assets), FNR includes the ARO costs associated with abandonment and reclamation of wells (wells, well sites, well site equipment and pipelines) with assigned reserves. For SCO assets, FNR includes the ARO costs associated with the abandonment and reclamation of the mine site and all mining facilities and for Horizon assets, it also includes abandonment and reclamation of the upgrading facilities. For North Sea and Offshore Africa, FNR includes the ARO costs associated with the abandonment and reclamation of offshore wells and facilities with assigned reserves.*

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 the Company's 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 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, development and deployment of technology and technological innovations and the assumption of operations at processing facilities 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 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 reserves and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the adequacy of the Company’s provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in 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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Special Note Regarding non-GAAP and other Financial Measures

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

Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating the Company's 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 and certain movements in other long-term assets. 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.

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 9 - Long-term Debt in the Company’s consolidated financial statements.

Finding, Development and Acquisition (“FD&A”) costs is a non-GAAP measure that is derived by dividing the sum of total net capital expenditures excluding midstream, abandonments, and head office, by the sum of total additions and revisions for the relevant reserves category. The Company considers FD&A costs a key measure in evaluating the Company's performance, as it provides the reader with an understanding of the Company’s ability to effectively find and develop reserves and make opportunistic acquisitions that add to the Company’s reserves base.

Recycle Ratio is a non-GAAP measure that is derived by dividing the operating netback by the FD&A cost for the relevant category. Operating netback for a segment or product is derived as product sales net of blending costs, less royalties, transportation and production expenses, calculated on a per BOE basis. The Company considers recycle ratio a key measure in evaluating the Company’s ability to generate profitability on its capital investment.

Reserves life index is based on the total reserves amount for the relevant category divided by the 2019 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.

Production replacement ratio is derived as the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.

Adjusted operating costs are derived as production expense based on sales volumes excluding costs incurred in turnaround periods. See "Operating Highlights - Oil Sands Mining and Upgrading" section in the Company’s MD&A.

Unadjusted operating costs also referred to as cash production costs in the Company’s MD&A. See "Operating Highlights - Oil Sands Mining and Upgrading" section in the Company’s MD&A.

Special Note Regarding Currency, Financial Information and Production

The Company's MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 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 months and year ended December 31, 2018 and the Company's MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout the Company's MD&A on a “before royalty” 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 royalty” or “net” basis is also presented for information purposes only.

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. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, March 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, March 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 4325867.

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.

CANADIAN NATURAL RESOURCES LIMITED

2100, 855 - 2nd Street S.W. Calgary, Alberta, T2P4J8
Phone: 403-514-7777 Email: ir@cnrl.com
www.cnrl.com

STEVE W. LAUT
Executive Vice-Chairman

TIM S. MCKAY
President

COREY B. BIEBER
Chief Financial Officer and Senior Vice-President, Finance

MARK A. STAINTHORPE
Vice-President, Finance – Capital Markets

Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange