CLR Investors

# Continental Resources Reports Second Quarter 2018 Results And Updates Full-Year Guidance

**$242.5 Million in Net Income, or $0.65 per Diluted Share**
**- $272.9 Million Adjusted Net Income, or $0.73 per Diluted Share (Non-GAAP)**
**$800 - $900 Million Annual Free Cash Flow (Non-GAAP) Target Maintained**
**2018 Annual Production Guidance Raised to 290,000 to 300,000 Boe per day**
**- 20% to 24% Year-over-Year Growth**
**2018 Exit Rate Guidance Increased to 315,000 to 325,000 Boe per Day**
**- Up 10,000 Boe per Day from Prior Guidance**
**2018 Capital Expenditures Guidance Increased from $2.3 to $2.7 Billion**
**- $275 Million Associated with Acquiring Minerals, Partially Funded by $220 Million in Proceeds Expected to be Received in 4Q18**
**- $125 Million of New Capital + $75 Million in Reallocated Capital Increases 2018 Drilling & Completions Budget by $200 Million**

OKLAHOMA CITY, Aug. 7, 2018 / PRNewswire/ --/PRNewswire/ -- Continental Resources, Inc. (NYSE: CLR) (the Company) today announced second quarter operating and financial results. The Company reported net income of $242.5 million, or $0.65 per diluted share, for the quarter ended June 30, 2018. The Company's net income includes certain items typically excluded by the investment community in published estimates, the result of which is referred to as "adjusted net income." In second quarter 2018, these typically excluded items in aggregate represented $30.4 million, or $0.08 per diluted share, of Continental's reported net income. Adjusted net income for second quarter 2018 was $272.9 million, or $0.73 per diluted share.

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Net cash provided by operating activities for second quarter 2018 was $753.8 million. EBITDAX for second quarter 2018 was $896.7 million. Definitions and reconciliations of adjusted net income, adjusted net income per share, free cash flow, EBITDAX, net debt, net sales prices and cash general and administrative (G&A) expenses per barrel of oil equivalent (Boe) presented herein to the most directly comparable U.S. generally accepted accounting principles (GAAP) financial measures are provided in the supporting tables at the conclusion of this press release.

As of June 30, 2018, the Company's balance sheet included approximately $130.0 million in cash and cash equivalents and $6.17 billion in total debt. During June, the Company achieved its short-term goal to drop below $6 billion in net debt. On June 30, 2018, net debt was slightly higher at $6.04 billion due to working capital changes and incremental acquired minerals. On July 12, 2018, the Company announced a partial call of its 5% Senior Notes Due 2022. This represents 20% ($400 million) of the $2 billion in aggregate principal amount of these notes currently outstanding. The Company continues to pursue its $5 billion long-term net debt goal. The Company's second quarter annualized net-debt-to-EBITDAX ratio was 1.68x and continues to approach the historically low levels seen prior to the three-year commodity down cycle.

The Company's second quarter 2018 crude oil differential was $4.55 per barrel below the NYMEX daily average for the period, an improvement of $1.76 per barrel compared to second quarter 2017. The realized wellhead natural gas price for second quarter 2018 was $0.15 per Mcf below the average NYMEX Henry Hub benchmark price. The Company expects to realize improved crude oil differentials in third quarter 2018 based on widening Brent/WTI spread and lower Cushing inventories.

**Updated 2018 Guidance**

The Company is increasing its 2018 annual production guidance to 290,000 to 300,000 Boe per day and is increasing its projected exit rate by 10,000 Boe per day to 315,000 to 325,000 Boe per day. This increase is driven primarily by Bakken outperformance, realized operational efficiencies and the reallocation of rigs to higher, non-carried working interest wells in SCOOP and STACK.

The Company also updated its 2018 Capex guidance from $2.3 billion to $2.7 billion. Approximately $275 million of this increase is associated with an investment in minerals within our existing leasehold, which is expected to be partially funded by mineral divestiture proceeds of approximately $220 million in fourth quarter 2018. New capital of $125 million and reallocated capital of $75 million will be used for additional drilling and completions (D&C) activity, including the addition of three rigs by year end, focused on high rate of return, oil-weighted assets. One-third of the D&C Capex increase is associated with higher value, 60-stage Bakken completions and two-thirds is associated with activity in Oklahoma.

Included within the updated 2018 Capex guidance is approximately $600 million for wells that will not have first production until 2019, providing a catalyst for continued oil-weighted production growth. The Company expects to exit 2018 with a wells in progress (WIP) inventory in the Bakken of approximately 130 gross operated wells, including approximately 50 already stimulated, with first production expected in 2019. In Oklahoma, the Company expects to exit 2018 with a WIP inventory of approximately 55 gross operated wells, including approximately 5 already stimulated, with first production expected in 2019. These wells will further prompt oil-focused growth in 2019.

"Continental is in an advantaged position in the current market, with high rate of return oil plays benefitting from existing infrastructure," said Harold Hamm, Chairman and Chief Executive Officer. "As we look into the second half of 2018 and beyond, Continental and its shareholders have an exciting opportunity to accelerate capital-efficient, oil-focused production growth while remaining disciplined in achieving our targets for free cash flow and debt reduction."

In the Bakken, the Company is projected to average 5 completion crews and 6 rigs in the second half of the year, ramping up to 7 rigs by year end. The Company expects to complete approximately 125 additional Bakken wells with first production by year end, with more than half of these in fourth quarter 2018. In Oklahoma, the Company is projected to average 4 completion crews and 18 rigs in the second half of the year, ramping up to 19 rigs at year end. Over 95% of our drilling activity in 2018 will be focused on oil and liquids-rich prospects.

The Company also improved guidance for select 2018 operating expenses. Total G&A expense, which is comprised of cash and non-cash G&A expense, is expected to be $1.60 to $2.15 per Boe in 2018. Of this total, cash G&A expense is expected to be $1.20 to $1.65 per Boe, a reduction from the previous $1.25 to $1.75 per Boe. Non-cash equity compensation is expected to be $0.40 to $0.50 per Boe, a reduction from the previous $0.45 to $0.55 per Boe. Continental also reduced 2018 guidance for DD&A to $17.00 to $18.00 per Boe for the year, down from the previous range of $17.00 to $19.00 due to strong well productivity and capital efficiency.

| **2018 Updated Guidance Metrics** | **Previous Guidance** | **Updated Guidance** |
|---|---|---|
| Annual production (Boe per day) | 285,000 to 300,000 | 290,000 to 300,000 |
| Exit rate production (Boe per day) | 305,000 to 315,000 | 315,000 to 325,000 |
| Capex (non-acquisition) | $2.3 billion | $2.7 billion |
| Cash G&A expense per Boe | $1.25 to $1.75 | $1.20 to $1.65 |
| Non-cash equity compensation per Boe | $0.45 to $0.55 | $0.40 to $0.50 |
| DD&A per Boe | $17.00 to $19.00 | $17.00 to $18.00 |

The Company's full 2018 guidance is stated in a table at the conclusion of this release.

**$220 Million Minerals Divestiture & Strategic Mineral Relationship Formed**

The Company announced yesterday the formation of a strategic minerals relationship with Franco-Nevada. The Company expects to receive approximately $220 million in net proceeds at closing in fourth quarter 2018. In addition, the parties have also committed, subject to satisfaction of agreed upon development thresholds, to spend up to a combined $125 million per year over the next three years to acquire additional minerals through the newly-formed subsidiary. With a carry component on capital acquisition costs, the Company is to fund 20% of future mineral acquisitions. The Company will be entitled to between 25% and 50% of total revenues generated by the minerals subsidiary based upon performance relative to certain predetermined targets. This new relationship is expected to enhance the value of minerals by targeting areas of the Company's future development in Oklahoma.

**Production Update**

Second quarter 2018 production totaled 25.8 million barrels of oil equivalent (Boe), or 284,059 Boe per day, up 26% from second quarter 2017. Total production for second quarter included 157,116 barrels of oil (Bo) per day and 761.7 million cubic feet (MMcf) of natural gas per day. The following table provides the Company's average daily production by region for the periods presented.

| *Boe per day* | 2Q 2018 | 1Q 2018 | 2Q 2017 | YTD 2018 | YTD 2017 |
|---|---|---|---|---|---|
| North Region: | | | | | |
| North Dakota Bakken | 151,805 | 154,503 | 112,397 | 153,147 | 106,736 |
| Montana Bakken | 6,314 | 6,853 | 7,464 | 6,582 | 7,720 |
| Red River Units | 8,404 | 9,338 | 9,878 | 8,868 | 9,983 |

| | | | | | |
|---|---|---|---|---|---|
| Other | 258 | 418 | 483 | 337 | 409 |
| South Region: | | | | | |
| SCOOP | 64,786 | 62,012 | 61,107 | 63,406 | 61,640 |
| STACK | 51,722 | 53,361 | 31,934 | 52,515 | 30,582 |
| Arkoma(1) | 9 | 2 | 1,788 | 6 | 1,771 |
| Other | 761 | 923 | 1,162 | 864 | 1,177 |
| Total | 284,059 | 287,410 | 226,213 | 285,725 | 220,018 |

(1) Producing properties comprising approximately 1,700 Boe per day of the Company's Arkoma production were sold in September 2017.

**Bakken: Record Results and Type Curve Uplifted to 1.2 MMBoe per Well**

The Company uplifted its type curve EUR for the Bakken 9% to 1,200 MBoe per well in the second quarter. This increase reflects the Company's move from 40-stage to 60-stage completions, based on improved performance observed from 70 wells completed with the Company's 60-stage optimized completion techniques. A 60-stage completion increases the cost of a typical Bakken well by approximately $0.5 million for a total completed well cost of $8.4 million. At this cost, the 1,200 MBoe type curve delivers a 175% rate of return (ROR) at $70 WTI and approximately $0.4 million of incremental cash flow per well in the first year, as compared to the Company's previous 1,100 MBoe type curve.

"Our Bakken team continues to unlock value for our shareholders through innovative thinking and advanced technologies," said Gary Gould, Senior Vice President of Production & Resource Development. "Over the past year, our team increased our Bakken type curve twice, cumulatively raising the EUR 22%, doubling the rate of return, and adding $3.5 million of incremental first-year cash flow per well for an additional cost of only $1.4 million per well. This step change in performance is uplifting Bakken economics throughout the field. With 4,000 wells of operated inventory still ahead of us, the Bakken will be a growth vehicle for Continental for many years to come."

The Company's Bakken production averaged 158,119 Boe per day in second quarter 2018, up 32% versus second quarter 2017. During the quarter, the Company completed 35 gross (19 net) operated wells flowing at an average initial 24-hour rate of 2,282 Boe per day. Four of the wells ranked as top ten 30-day rate Bakken wells for the Company, including the first 30-day Bakken well to average over 3,000 Boe per day (Mountain Gap 7-10H in Dunn County, 3,104 Boe per day).

**SCOOP: Project SpringBoard Phase I and Phase II Underway**

The Company's SCOOP production averaged 64,786 Boe per day in second quarter 2018, up 6% versus second quarter 2017. The Company completed 16 gross (13 net) operated wells with first production in second quarter 2018.

The Company previously announced Project SpringBoard, which is a massive, multi-year, stacked pay, oil development project that covers approximately 70-square miles and includes 45,000 gross (31,000 net) contiguous acres. SpringBoard holds up to 400 MMBoe of gross unrisked resource potential, with wells expecting to average 70%-85% oil across both phases. The Company estimates up to 100 Springer and 250 Woodford and Sycamore potential locations and will operate SpringBoard with an average working interest of approximately 75%. In addition, SpringBoard is expected to benefit from the Company's row development operational efficiencies and production will benefit from access to premium markets through existing pipeline infrastructure.

Drilling is underway in both Phase I and Phase II of Project SpringBoard, with 7 rigs targeting the Springer reservoir (Phase I) and 4 rigs, ramping up to 6 rigs by year end, targeting the Woodford and Sycamore reservoirs (Phase II). The Company expects first production from the Springer wells in Project SpringBoard to begin late third quarter 2018, with up to 18 Springer wells producing by year end 2018. First production from the Woodford and Sycamore wells is expected to begin in first quarter 2019.

"Project SpringBoard is an outstanding, high impact oil project for Continental and its shareholders," said Jack Stark, President. "This project alone has the potential to increase Continental's oil production by as much as 10% over the next 12 months."

**STACK: Oil Window Drilling Accelerated with Strong Well Results**

The Company's STACK production increased 62% to 51,722 Boe per day in second quarter 2018, compared to second quarter 2017. Continental completed 26 gross (13 net) operated wells with first production in second quarter 2018. The top Company-operated STACK oil wells in second quarter include the Swaim 3-14H: 3,476 Boepd (2,596 Bopd), Madeline 2-4-9XH: 3,540 Boepd (2,548 Bopd), Lugene 1-33H: 3,600 Boepd (2,004 Bopd), Nelda 1-3-10XH: 4,032 Boepd (1,886 Bopd) and Brown Family 1-13-24XH: 3,065 Boepd (1,443 Bopd).

**Financial Update**

"Continental's positive revisions to production guidance reflect the oil-focused opportunity we see in accelerating our activity in a capital-efficient manner. The momentum built from these decisions will directly correlate to revenue generation and oil-weighted growth as we enter the back half of 2018 and 2019," said John Hart, Chief Financial Officer. "Continental will conduct the capital spend from both our D&C activity and our new minerals opportunity in a manner supportive of cash flow enhancement and debt reduction."

In second quarter 2018, the Company's average net sales price excluding the effects of derivative positions was $63.35 per barrel of oil and $2.65 per Mcf of gas, or $42.16 per Boe.

Production expense per Boe was $3.49 for second quarter 2018, which represented an $0.11 quarter over quarter improvement versus first quarter 2018 and a $0.50 year over year improvement versus second quarter 2017. Other select operating costs and expenses for second quarter 2018 included production taxes of 7.7% of net crude oil and natural gas sales; DD&A of $17.29 per Boe; and total G&A of $1.82 per Boe.

Non-acquisition capital expenditures for second quarter 2018 totaled approximately $714.2 million, including $627.9 million in exploration and development drilling, $44.9 million in leasehold, and $41.4 million in workovers, recompletions and other.

The following table provides the Company's production results, per-unit operating costs, results of operations and certain non-GAAP financial measures for the periods presented. Average net sales prices exclude any effect of derivative transactions. Per-unit expenses have been calculated using sales volumes.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Average daily production: | | | | |
| Crude oil (Bbl per day) | 157,116 | 125,381 | 160,458 | 122,308 |
| Natural gas (Mcf per day) | 761,653 | 604,991 | 751,603 | 586,263 |
| Crude oil equivalents (Boe per day) | 284,059 | 226,213 | 285,725 | 220,018 |
| Average net sales prices (non-GAAP), excluding effect from derivatives: (1) | | | | |
| Crude oil ($/Bbl) | $63.35 | $41.91 | $61.14 | $43.26 |
| Natural gas ($/Mcf) | $2.65 | $2.63 | $2.81 | $2.81 |
| Crude oil equivalents ($/Boe) | $42.16 | $30.31 | $41.71 | $31.56 |
| Production expenses ($/Boe) | $3.49 | $3.99 | $3.54 | $3.89 |
| Production taxes (% of net crude oil and gas sales) | 7.7% | 6.7% | 7.6% | 6.6% |
| DD&A ($/Boe) | $17.29 | $19.14 | $17.45 | $19.48 |
| Total general and administrative expenses ($/Boe) (2) | $1.82 | $1.89 | $1.75 | $2.16 |
| Net income (loss) (in thousands) | $242,464 | ($63,557) | $476,410 | ($63,088) |
| Diluted net income (loss) per share | $0.65 | ($0.17) | $1.27 | ($0.17) |
| Adjusted net income (loss) (non-GAAP) (in thousands) (1) | $272,877 | ($1,801) | $528,016 | $4,979 |
| Adjusted diluted net income (loss) per share (non-GAAP) (1) | $0.73 | $0.00 | $1.41 | $0.01 |
| Net cash provided by operating activities (in thousands) | 753,802 | $446,371 | 1,639,993 | $916,572 |
| EBITDAX (non-GAAP) (in thousands) (1) | 896,654 | $479,490 | 1,772,850 | $961,963 |

(1) Net sales prices, adjusted net income (loss), adjusted diluted net income (loss) per share, and EBITDAX represent non-GAAP financial measures. Further information about these non-GAAP financial measures as well as reconciliations to the most directly comparable U.S. GAAP financial measures are provided subsequently under the header *Non-GAAP Financial Measures*.

(2) Total general and administrative expense is comprised of cash general and administrative expense and non-cash equity compensation expense. Cash general and administrative expense per Boe was $1.41, $1.45, $1.33, and $1.65 for 2Q 2018, 2Q 2017, YTD 2018 and YTD 2017, respectively. Non-cash equity compensation expense per Boe was $0.41, $0.44, $0.42, and $0.51 for 2Q 2018, 2Q 2017, YTD 2018 and YTD 2017, respectively.

**Second Quarter Earnings Conference Call**

Continental plans to host a conference call to discuss second quarter results on Wednesday, August 8, 2018, at 12 p.m. ET (11 a.m. CT). Those wishing to listen to the conference call may do so via the Company's website at http://www.clr.com/ or by phone:

| | |
|---|---|
| Time and date: | 12 p.m. ET, Wednesday, August 8, 2018 |
| Dial in: | 844-309-6572 |
| Intl. dial in: | 484-747-6921 |
| Pass code: | 4798234 |

A replay of the call will be available for 14 days on the Company's website or by dialing:

| | |
|---|---|
| Replay number: | 855-859-2056 or 404-537-3406 |
| Intl. replay: | 800-585-8367 |
| Pass code: | 4798234 |

Continental plans to publish a second quarter 2018 summary presentation to its website at [http://www.clr.com/](http://www.clr.com/) prior to the start of its earnings conference call on August 8, 2018.

**Upcoming Conferences**

Members of Continental's management team plan to participate in the following investment conferences:
August 15-16, 2018 Heikkinen Energy Conference
September 4-6, 2018 Barclays Global CEO-Energy Power Conference

Presentation materials for all conferences mentioned above will be available on the Company's web site at www.CLR.com prior to the start of the Company's presentation at the applicable conference. For each presentation, the Company will utilize its web site to post updated materials or indicate which previously posted presentation materials will be used for the conference in question.

**About Continental Resources**

Continental Resources (NYSE: CLR) is a top 10 independent oil producer in the U.S. Lower 48 and a leader in America's energy renaissance. Based in Oklahoma City, Continental is the largest leaseholder and the largest producer in the nation's premier oil field, the Bakken play of North Dakota and Montana. The Company also has significant positions in Oklahoma, including its SCOOP Woodford and SCOOP Springer discoveries and the STACK plays. With a focus on the exploration and production of oil, Continental has unlocked the technology and resources vital to American energy independence and our nation's leadership in the new world oil market. In 2018, the Company will celebrate 51 years of operations. For more information, please visit [http://www.clr.com/](http://www.clr.com/).

**Cautionary Statement for the Purpose of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995**

This press release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements included in this press release other than statements of historical fact, including, but not limited to, forecasts or expectations regarding the Company's business and statements or information concerning the Company's future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows are forward-looking statements. When used in this press release, the words "could," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," "budget," "plan," "continue," "potential," "guidance," "strategy," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements are based on the Company's current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. Although the Company believes these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. The risks and uncertainties include, but are not limited to, commodity price volatility; the geographic concentration of our operations; financial market and economic volatility; the inability to access needed capital; the risks and potential liabilities inherent in crude oil and natural gas drilling and production and the availability of insurance to cover any losses resulting therefrom; difficulties in estimating proved reserves and other reserves-based measures; declines in the values of our crude oil and natural gas properties resulting in impairment charges; our ability to replace proved reserves and sustain production; the availability or cost of equipment and oilfield services; leasehold terms expiring on undeveloped acreage before production can be established; our ability to project future production, achieve targeted results in drilling and well operations and predict the amount and timing of development expenditures; the availability and cost of transportation, processing and refining facilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing; increased market and industry competition, including from alternative fuels and other energy sources; and the other risks described under Part I, Item 1A. Risk Factors and elsewhere in the Company's Annual Report on Form 10-K for the year ended December 31, 2017, registration statements and other reports filed from time to time with the SEC, and other announcements the Company makes from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date on which such statement is made. Should one or more of the risks or uncertainties described in this press release occur, or should underlying assumptions prove incorrect, the Company's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. Except as otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this report, or otherwise.

Readers are cautioned that initial production rates are subject to decline over time and should not be regarded as reflective of sustained production levels. In particular, production from horizontal drilling in shale oil and natural gas resource plays and tight natural gas plays that are stimulated with extensive pressure fracturing are typically characterized by significant early declines in production rates.

We use the term "EUR" or "estimated ultimate recovery" to describe potentially recoverable oil and natural gas hydrocarbon quantities. We include these estimates to demonstrate what we believe to be the potential for future drilling and production on our properties. These estimates are by their nature much more speculative than estimates of proved reserves and require substantial capital spending to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from our properties will differ substantially. EUR data included herein remain subject to change as more well data is analyzed.

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Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Income (Loss)

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Revenues: | *In thousands, except per share data* | | | |
| Crude oil and natural gas sales | $ 1,137,528 | $ 626,548 | $ 2,251,380 | $ 1,260,398 |
| Gain (loss) on natural gas derivatives, net | (12,685) | 28,022 | (2,511) | 74,880 |
| Crude oil and natural gas service operations | 12,270 | 6,916 | 29,272 | 11,636 |
| Total revenues | 1,137,113 | 661,486 | 2,278,141 | 1,346,914 |
| Operating costs and expenses: | | | | |
| Production expenses | 90,171 | 82,474 | 183,133 | 155,328 |
| Production taxes | 83,595 | 41,965 | 164,175 | 83,198 |
| Transportation expenses | 47,254 | - | 96,551 | - |
| Exploration expenses | 303 | 3,204 | 2,023 | 8,202 |
| Crude oil and natural gas service operations | 7,688 | 4,478 | 12,271 | 7,315 |
| Depreciation, depletion, amortization and accretion | 447,200 | 395,770 | 901,578 | 777,926 |
| Property impairments | 29,162 | 123,316 | 62,946 | 174,689 |
| General and administrative expenses | 47,174 | 39,186 | 90,217 | 86,407 |
| Net (gain) loss on sale of assets and other | (6,710) | 134 | (6,751) | 5,669 |
| Total operating costs and expenses | 745,837 | 690,527 | 1,506,143 | 1,298,734 |
| Income (loss) from operations | 391,276 | (29,041) | 771,998 | 48,180 |
| Other income (expense): | | | | |

| | | | | |
|---|---|---|---|---|
| Interest expense | (74,288) | (72,744) | (150,182) | (143,916) |
| Other | 708 | 373 | 1,362 | 815 |
| | (73,580) | (72,371) | (148,820) | (143,101) |
| Income (loss) before income taxes | 317,696 | (101,412) | 623,178 | (94,921) |
| (Provision) benefit for income taxes | (75,232) | 37,855 | (146,768) | 31,833 |
| Net income (loss) | $ 242,464 | $ (63,557) | $ 476,410 | $ (63,088) |
| Basic net income (loss) per share | $ 0.65 | $ (0.17) | $ 1.28 | $ (0.17) |
| Diluted net income (loss) per share | $ 0.65 | $ (0.17) | $ 1.27 | $ (0.17) |

Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Balance Sheets

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| **Assets** | *In thousands* | |
| Cash and cash equivalents | $ 129,989 | $ 43,902 |
| Other current assets | 1,311,300 | 1,207,823 |
| Net property and equipment (1) | 13,339,571 | 12,933,789 |
| Other noncurrent assets | 17,620 | 14,137 |
| Total assets | $ 14,798,480 | $ 14,199,651 |
| | | |
| **Liabilities and shareholders' equity** | | |
| Current liabilities | $ 1,484,439 | $ 1,330,242 |
| Long-term debt, net of current portion | 6,164,221 | 6,351,405 |
| Other noncurrent liabilities | 1,536,332 | 1,386,801 |
| Total shareholders' equity | 5,613,488 | 5,131,203 |
| Total liabilities and shareholders' equity | $ 14,798,480 | $ 14,199,651 |

(1) Balance is net of accumulated depreciation, depletion and amortization of $9.88 billion and $9.08 billion as of June 30, 2018 and December 31, 2017, respectively.

Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Cash Flows

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| *In thousands* | 2018 | 2017 | 2018 | 2017 |
| Net income (loss) | $ 242,464 | $ (63,557) | $ 476,410 | $ (63,088) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | | |
| Non-cash expenses | 576,109 | 465,966 | 1,145,283 | 877,921 |
| Changes in assets and liabilities | (64,771) | 43,962 | 18,300 | 101,739 |
| Net cash provided by operating activities | 753,802 | 446,371 | 1,639,993 | 916,572 |
| Net cash used in investing activities | (715,392) | (490,049) | (1,343,603) | (879,320) |
| Net cash (used in) provided by financing activities | (6,553) | 43,666 | (210,277) | (36,719) |
| Effect of exchange rate changes on cash | (13) | 14 | (26) | 14 |
| Net change in cash and cash equivalents | 31,844 | 2 | 86,087 | 547 |
| Cash and cash equivalents at beginning of period | 98,145 | 17,188 | 43,902 | 16,643 |
| Cash and cash equivalents at end of period | $ 129,989 | $ 17,190 | $ 129,989 | $ 17,190 |

## Non-GAAP Financial Measures

### *Adjusted earnings (net income/loss) and adjusted earnings (net income/loss) per share*

Our presentation of adjusted earnings and adjusted earnings per share that exclude the effect of certain items are non-GAAP financial measures. Adjusted earnings and adjusted earnings per share represent earnings and diluted earnings per share determined under U.S. GAAP without regard to non-cash gains and losses on derivative instruments, property impairments, gains and losses on asset sales, and losses on extinguishment of debt as applicable. Management believes these measures provide useful information to analysts and investors for analysis of our operating results. In addition, management believes these measures are used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis without regard to an entity's specific derivative portfolio, impairment methodologies, and property dispositions. Adjusted earnings and adjusted earnings per share should not be considered in isolation or as an alternative to, or more meaningful than, earnings or diluted earnings per share as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies. The following table reconciles earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

| | Three months ended June 30, | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| *In thousands, except per share data* | $ | Diluted EPS | $ | Diluted EPS |
| Net income (loss) (GAAP) | $ 242,464 | $ 0.65 | $ (63,557) | $ (0.17) |
| Adjustments: | | | | |
| Non-cash (gain) loss on derivatives | 17,443 | | (23,265) | |
| Property impairments | 29,162 | | 123,316 | |
| Gain on sale of assets | (6,711) | | (780) | |
| Total tax effect of adjustments (1) | (9,481) | | (37,515) | |
| Total adjustments, net of tax | 30,413 | 0.08 | 61,756 | 0.17 |
| Adjusted net income (loss) (non-GAAP) | $ 272,877 | $ 0.73 | $ (1,801) | $0.00 |
| Weighted average diluted shares outstanding | 374,505 | | 371,111 | |
| Adjusted diluted net income (loss) per share (non-GAAP) | $ 0.73 | | $0.00 | |

| | Six months ended June 30, | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| *In thousands, except per share data* | $ | Diluted EPS | $ | Diluted EPS |
| Net income (loss) (GAAP) | $ 476,410 | $ 1.27 | $ (63,088) | $ (0.17) |
| Adjustments: | | | | |
| Non-cash (gain) loss on derivatives | 11,465 | | (68,420) | |
| Property impairments | 62,946 | | 174,689 | |
| (Gain) loss on sale of assets | (6,751) | | 2,859 | |
| Total tax effect of adjustments (1) | (16,054) | | (41,061) | |
| Total adjustments, net of tax | 51,606 | 0.14 | 68,067 | 0.18 |
| Adjusted net income (non-GAAP) | $ 528,016 | $ 1.41 | $ 4,979 | $ 0.01 |
| Weighted average diluted shares outstanding | 374,583 | | 373,518 | |
| Adjusted diluted net income per share (non-GAAP) | $ 1.41 | | $ 0.01 | |

(1) Computed by applying a combined federal and state statutory tax rate of 24% in effect for 2018 and 38% in effect for 2017 to the pre-tax amount of adjustments associated with our operations in the United States.

### *Net debt*

Net debt is a non-GAAP measure. We define net debt as total debt less cash and cash equivalents as determined under U.S. GAAP. Net debt should not be considered an alternative to, or more meaningful than, the comparable GAAP measure. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. We believe this metric is useful to analysts and investors in determining the Company's leverage position since the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt. This metric is sometimes presented as a ratio with EBITDAX in order to provide investors with another means of evaluating the Company's ability to service its existing debt obligations as well as any future increase in the amount of such obligations. At June 30, 2018, the Company's net debt amounted to $6.04 billion, representing total debt of $6.17 billion less cash and cash equivalents of $130.0 million. From time to time the Company provides forward-looking net debt forecasts; however, the Company is unable to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. The reconciling items in future periods could be significant.

***EBITDAX***

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, non-cash equity compensation expense, and losses on extinguishment of debt as applicable. EBITDAX is not a measure of net income or net cash provided by operating activities as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. Further, we believe EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income/loss and net cash provided by operating activities in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

EBITDAX should not be considered as an alternative to, or more meaningful than, net income/loss or net cash provided by operating activities as determined in accordance with U.S. GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation of our net income/loss to EBITDAX for the periods presented.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| *In thousands* | 2018 | 2017 | 2018 | 2017 |
| Net income (loss) | $ 242,464 | $ (63,557) | $ 476,410 | $ (63,088) |
| Interest expense | 74,288 | 72,744 | 150,182 | 143,916 |
| Provision (benefit) for income taxes | 75,232 | (37,855) | 146,768 | (31,833) |
| Depreciation, depletion, amortization and accretion | 447,200 | 395,770 | 901,578 | 777,926 |
| Property impairments | 29,162 | 123,316 | 62,946 | 174,689 |
| Exploration expenses | 303 | 3,204 | 2,023 | 8,202 |
| Impact from derivative instruments: | | | | |
| Total (gain) loss on derivatives, net | 12,685 | (27,109) | 2,511 | (72,070) |
| Total cash received on derivatives, net | 4,758 | 3,844 | 8,954 | 3,650 |
| Non-cash (gain) loss on derivatives, net | 17,443 | (23,265) | 11,465 | (68,420) |
| Non-cash equity compensation | 10,562 | 9,133 | 21,478 | 20,571 |
| EBITDAX (non-GAAP) | $ 896,654 | $ 479,490 | $ 1,772,850 | $ 961,963 |

The following table provides a reconciliation of our net cash provided by operating activities to EBITDAX for the periods presented.

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| *In thousands* | 2018 | 2017 | 2018 | 2017 |
| Net cash provided by operating activities | $ 753,802 | $ 446,371 | $ 1,639,993 | $ 916,572 |
| Current income tax provision | - | - | - | 1 |
| Interest expense | 74,288 | 72,744 | 150,182 | 143,916 |
| Exploration expenses, excluding dry hole costs | 303 | 3,204 | 2,022 | 8,045 |

| | | | | |
|---|---|---|---|---|
| Gain (loss) on sale of assets, net | 6,711 | 780 | 6,751 | (2,859) |
| Other, net | (3,221) | 353 | (7,798) | (1,973) |
| Changes in assets and liabilities | 64,771 | (43,962) | (18,300) | (101,739) |
| EBITDAX (non-GAAP) | $ 896,654 | $ 479,490 | $ 1,772,850 | $ 961,963 |

***Free cash flow***

Our presentation of free cash flow is a non-GAAP measure. We define free cash flow as cash flows from operations before changes in working capital items less capital expenditures, excluding acquisitions, plus non-controlling interest capital contributions, less distributions to non-controlling interests. The inclusion of non-controlling interest capital contributions and distributions, expected to begin in the fourth quarter of 2018, is related to our newly formed relationship with Franco-Nevada to fund a portion of certain mineral acquisitions which are included in our capital expenditures and operating results. Free cash flow is not a measure of net income or cash flows as determined by U.S. GAAP and should not be considered an alternative to, or more meaningful than, the comparable GAAP measure. Management believes that these measures are useful to management and investors as a measure of a company's ability to internally fund its capital expenditures and to service or incur additional debt. These measures eliminate the impact of certain items that management does not consider to be indicative of the Company's performance from period to period. From time to time the Company provides forward-looking free cash flow estimates; however, the Company is unable to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. The reconciling items in future periods could be significant.

***Net sales prices***

On January 1, 2018, we adopted Accounting Standards Update 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net)*, which impacted the presentation of our crude oil and natural gas revenues. We adopted the new rules using a modified retrospective transition approach whereby changes have been applied only to the most current period presented and prior period results have not been adjusted to conform to current presentation.

Under the new rules, revenues and transportation expenses associated with production from our operated properties are now reported on a gross basis compared to net presentation in the prior year. For non-operated properties, we receive a net payment from the operator for our share of sales proceeds which is net of costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds received, consistent with our historical practice. As a result, beginning January 1, 2018 the gross presentation of revenues from our operated properties differs from the net presentation of revenues from non-operated properties. This impacts the comparability of certain operating metrics, such as per-unit sales prices, when such metrics are prepared in accordance with U.S. GAAP using gross presentation for some revenues and net presentation for others.

In order to provide metrics prepared in a manner consistent with how management assesses the Company's operating results, and to achieve comparability with prior period metrics for analysis purposes, we may present crude oil and natural gas sales net of transportation expenses, which we refer to as "net crude oil and natural gas sales," a non-GAAP measure. Average sales prices calculated using net crude oil and natural gas sales are referred to as "net sales prices," a non-GAAP measure, and are calculated by taking revenues less transportation expenses divided by sales volumes, whether for crude oil or natural gas, as applicable. Management believes presenting our revenues and sales prices net of transportation expenses is useful because it normalizes the presentation differences between operated and non-operated revenues and allows for a useful comparison of net realized prices to NYMEX benchmark prices on a Company-wide basis.

The following table presents a reconciliation of crude oil and natural gas sales (GAAP) to net crude oil and natural gas sales and related net sales prices (non-GAAP) for the three and six months ended June 30, 2018. Information is also presented for the three and six months ended June 30, 2017 for comparative purposes.

| | Three months ended June 30, 2018 | | | Three months ended June 30, 2017 | | |
|---|---|---|---|---|---|---|
| *In thousands* | Crude oil | Natural gas | Total | Crude oil | Natural gas | Total |
| Crude oil and natural gas sales (GAAP) | $946,884 | $190,644 | $1,137,528 | $481,898 | $144,650 | $626,548 |
| Less: Transportation expenses | (40,217) | (7,037) | (47,254) | — | — | — |
| Net crude oil and natural gas sales (non-GAAP for 2018) | $906,667 | $183,607 | $1,090,274 | $481,898 | $144,650 | $626,548 |
| Sales volumes (MBbl/MMcf/MBoe) | 14,311 | 69,310 | 25,863 | 11,499 | 55,054 | 20,674 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Net sales price (non-GAAP for 2018) | $63.35 | $2.65 | $42.16 | $41.91 | $2.63 | $30.31 |

| | Six months ended June 30, 2018 | | | Six months ended June 30, 2017 | | |
|---|---|---|---|---|---|---|
| *In thousands* | Crude oil | Natural gas | Total | Crude oil | Natural gas | Total |
| Crude oil and natural gas sales (GAAP) | $1,853,165 | $398,215 | $2,251,380 | $962,539 | $297,859 | $1,260,398 |
| Less: Transportation expenses | (80,603) | (15,948) | (96,551) | — | — | — |
| Net crude oil and natural gas sales (non-GAAP for 2018) | $1,772,562 | $382,267 | $2,154,829 | $962,539 | $297,859 | $1,260,398 |
| Sales volumes (MBbl/MMcf/MBoe) | 28,993 | 136,040 | 51,667 | 22,253 | 106,114 | 39,938 |
| Net sales price (non-GAAP for 2018) | $61.14 | $2.81 | $41.71 | $43.26 | $2.81 | $31.56 |

**Cash general and administrative expenses per Boe**

Our presentation of cash general and administrative ("G&A") expenses per Boe is a non-GAAP measure. We define cash G&A per Boe as total G&A determined in accordance with U.S. GAAP less non-cash equity compensation expenses, expressed on a per-Boe basis. We report and provide guidance on cash G&A per Boe because we believe this measure is commonly used by management, analysts and investors as an indicator of cost management and operating efficiency on a comparable basis from period to period. In addition, management believes cash G&A per Boe is used by analysts and others in valuation, comparison and investment recommendations of companies in the oil and gas industry to allow for analysis of G&A spend without regard to stock-based compensation programs which can vary substantially from company to company. Cash G&A per Boe should not be considered as an alternative to, or more meaningful than, total G&A per Boe as determined in accordance with U.S. GAAP and may not be comparable to other similarly titled measures of other companies.

Continental Resources, Inc.
2018 Guidance
As of August 7, 2018

| | Previous 2018 | Updated 2018 |
|---|---|---|
| Full-year average production | 285,000 to 300,000 Boe per day | 290,000 to 300,000 Boe per day |
| Exit-rate average production | 305,000 to 315,000 Boe per day | 315,000 to 325,000 Boe per day |
| Capital expenditures (non-acquisition) | $2.3 billion | $2.7 billion |
| Operating Expenses: | | |
| Production expense per Boe | $3.00 to $3.50 | $3.00 to $3.50 |
| Production tax (% of net oil & gas revenue) | 7.6% to 8.0% | 7.6% to 8.0% |
| Cash G&A expense per Boe(1) | $1.25 to $1.75 | $1.20 to $1.65 |
| Non-cash equity compensation per Boe | $0.45 to $0.55 | $0.40 to $0.50 |
| DD&A per Boe | $17.00 to $19.00 | $17.00 to $18.00 |
| Average Price Differentials: | | |
| NYMEX WTI crude oil (per barrel of oil) | ($3.50) to ($4.50) | ($3.50) to ($4.50) |
| Henry Hub natural gas (per Mcf) | $0.00 to +$0.50 | $0.00 to +$0.50 |

(1) Cash G&A is a non-GAAP measure and excludes the range of values shown for non-cash equity compensation per Boe in the item appearing immediately below. Guidance for total G&A (cash and non-cash) is an expected range of $1.60 to $2.15 per Boe.

http://investors.clr.com/2018-08-07-Continental-Resources-Reports-Second-Quarter-2018-Results-And-Updates-Full-Year-Guidance-1