NEWS RELEASE

CONTINENTAL RESOURCES REPORTS FOURTH QUARTER AND FULL-YEAR 2016 RESULTS

Oklahoma City, February 22, 2017 – Continental Resources, Inc. (NYSE: CLR) (the Company) today announced fourth quarter and full-year 2016 operating and financial results. Continental reported net income of $27.7 million, or $0.07 per diluted share, for the quarter ended December 31, 2016. For full-year 2016, the Company reported a net loss of $399.7 million, or $1.08 per diluted share.

The Company's net income or net loss includes certain items typically excluded by the investment community in published estimates, the result of which is referred to as "adjusted net loss." In fourth quarter 2016, these typically excluded items in aggregate represented $55.1 million, or $0.14 per diluted share, of Continental's reported net income. Adjusted net loss for the fourth quarter was $27.4 million, or $0.07 per diluted share. For full-year 2016, these typically excluded items in aggregate represented $73.0 million, or $0.20 per diluted share. Adjusted net loss for full-year 2016 was $326.6 million, or $0.88 per diluted share.

Key Achievements/Value-Drivers

- Seven STACK Meramec completions in the over-pressured oil window with initial production of 1,604 to 2,463 barrels of oil equivalent (Boe) per day with 55% to 73% crude oil.
- STACK leasehold now stands at more than 200,000 net acres, up approximately 45,000 net acres from year-end 2015.
- SCOOP Woodford condensate type curve estimated ultimate recovery (EUR) raised an additional 15% to 2.3 MMBoe per well.
- Early production from recent Bakken wells exceeding 980 MBoe EUR type curve by 35%.
- Premier asset portfolio provides inventory for multi-year production growth of 20% on a cash neutral basis.
- Year-end 2016 proved reserves increased 4% to 1.27 billion Boe despite lower commodity prices.

Net cash provided by operating activities for fourth quarter 2016 was $262.0 million and $1.13 billion for full-year 2016. EBITDAX for fourth quarter 2016 was $652.4 million, contributing to full-year 2016 EBITDAX of $1.9 billion. Definitions and reconciliations of adjusted net loss, adjusted net loss per share and EBITDAX to the most directly comparable U.S. generally accepted accounting principles (GAAP) financial measures can be found in the supporting tables at the conclusion of this press release.

“I am very proud of our accomplishments in 2016. In another year of volatile commodity markets, Continental’s performance really stood out,” said Harold Hamm, Chairman and Chief Executive Officer. “Among our key achievements, we expanded the extent of the over-pressured oil window in STACK and are now beginning density development in this premier Oklahoma play. Also, using the latest enhanced completion designs, we set new Company early production records for wells in STACK, SCOOP and the Bakken.

“In the North Dakota Bakken, we began harvesting our high-value backlog of uncompleted wells that will benefit production and cash generation in 2017 and 2018,” he said. “I’m also proud that Continental did not dilute shareholders by issuing equity in an adverse market in the past two years. We reduced debt by more than $600 million from its peak in May of 2016 and expect to continue to reduce debt this year.

“Looking to 2017, our strategy is to remain disciplined in our spending to deliver full value to shareholders. We are focused on oil-concentrated production growth and strong investment returns as oil prices stabilize at higher levels,” Mr. Hamm said. “As we announced in late January, we expect multi-year production growth of 20% on a cash neutral basis.”

Production

Fourth quarter 2016 net production totaled 19.3 million Boe, or approximately 210,000 Boe per day, up slightly from third quarter 2016. Severe weather primarily in the Bakken reduced total production for the fourth quarter by approximately 6,500 Boe per day. February production is estimated to be approximately 215,000 Boe per day, an increase from January, which was also impacted by weather.

Total net production for fourth quarter 2016 included 116,500 barrels of oil (Bo) per day (55% of production) and 560.3 million cubic feet (MMcf) of natural gas per day (45% of production). Full-year 2016 production averaged 216,900 Boe per day. As announced in January, Continental expects to exit 2017 with production in a range of 250,000 to 260,000 Boe per day, a 19%-to-24% increase compared with fourth quarter 2016 production.

The following table provides the Company’s average daily production by region for the periods presented.

Boe per day	4Q 2016	3Q 2016	4Q 2015	FY 2016	FY 2015
North Region:					
North Dakota Bakken	96,035	99,251	125,583	109,686	124,503
Montana Bakken	8,489	8,678	10,772	9,514	12,617
Red River Units	10,140	10,475	11,654	10,745	12,342
Other	4,109	1,189	902	1,665	1,103
South Region:					
SCOOP	63,490	67,462	64,534	65,062	61,586
STACK	24,426	17,680	7,709	16,983	5,560
Arkoma	1,929	1,833	2,124	1,915	2,104
Other	1,243	1,272	1,658	1,342	1,900
Total	209,861	207,840	224,936	216,912	221,715

STACK Continues to Expand

STACK production increased 38% to approximately 24,400 Boe per day in fourth quarter 2016, compared with third quarter 2016. Production of approximately 17,000 Boe per day for full-year 2016 was three times STACK production for 2015, reflecting the ramp up in activity throughout 2016.

Continental has increased its STACK Meramec leasehold to more than 200,000 net acres, compared with 155,000 net acres at year-end 2015. The Company currently has 12 operated rigs in STACK, with seven targeting the Meramec formation in the over-pressured oil window and five targeting the Woodford formation in the Northwest Cana joint development agreement (JDA) area in Blaine and Custer counties.

The Company reported seven new completions in the STACK Meramec over-pressured oil window for the fourth quarter. Initial 24-hour production test rates for these wells were as follows:

- 2,463 Boe per day (73% oil) from a 9,800-foot lateral (Roth 1-26-35XH);
- 2,263 Boe per day (68% oil) from a 4,760-foot lateral (Glenwood Pearl 1-19H);
- 2,239 Boe per day (71% oil) from a 9,365-foot lateral (Zella 1-4-9XH);
- 2,152 Boe per day (62% oil) from a 4,700-foot lateral (Homsey 1-22H);
- 1,929 Boe per day (72% oil) from a 4,575-foot lateral (Laura FIU 1-4H);
- 1,822 Boe per day (55% oil) from a 9,700-foot lateral (Sherry Lanelle Federal 1-31-30XH);
- 1,604 Boe per day (70% oil) from a 10,500-foot lateral (Wintersole 1-4-33-28XH).

Flowing casing pressures ranged from 2,850 to 3,925 pounds per square inch (psi).

Approximately 47,000 net acres, or 60% of the Company's leasehold in the over-pressured oil window of STACK, has been de-risked and is in development. This includes an estimated 55 operated units that the Company expects will be developed in two Meramec zones, as well as in the Woodford, with a pattern of up to six wells per zone.

Continental is currently drilling or completing five of these units, including the Bernhardt, Blurton, Gillilan, Verona, and Compton units, and it plans to commence a sixth test in the Angus Trust unit in the over-pressured condensate window. These density tests will include up to six wells per zone in combinations of the Upper, Middle and Lower Meramec and the Woodford.

The results of the Company's first density test at the Ludwig unit were announced in November 2016. To date, the eight Meramec wells in the Ludwig unit have produced a combined 1.75 MMBoe.

Deep STACK Success

Another key success in second half 2016 was Continental's completion of three Meramec wells in the over-pressured gas window of STACK. These three wells are located in the southwestern part of the Company's leasehold, in an area called Deep STACK, where the Meramec is encountered at depths of at least 13,000 feet.

Initial 24-hour production test rates included:

- 22.2 MMcf and 49 Bo per day from a 9,700-foot lateral (Andersons Half 1-30-19XH);
- 20.1 MMcf and 84 Bo per day from a 9,700-foot lateral (Eichelberger 1-28-21XH); and
- 20.1 MMcf and 78 Bo per day from a 9,700-foot lateral (Edith Mae 1-24-25XH).

Flowing casing pressures ranged from 5,900 to 7,500 psi.

Combined, the three wells have produced 5.8 Bcf and 12.3 MBo and are currently producing 50 MMcf per day and 100 Bo per day at flowing casing pressures between 4,000 and 5,000 psi.

Wells in Deep STACK are projected to have an average EUR of 20 Bcf per well from a 9,800-foot lateral. This would generate an approximate 50% rate of return at a completed well cost of $11.0 million, based on $3.50 per Mcf of gas.

"STACK has clearly become a key catalyst for Continental's growth," said Jack Stark, Continental's President and Chief Operating Officer. "We have never had a play this prolific evolve so quickly. The results have exceeded our early expectations, and the impact on Continental's production growth both near term and long term will be significant."

SCOOP

In fourth quarter 2016, SCOOP net production averaged 63,490 Boe per day (27% oil), or 30% of the Company's total production in fourth quarter. Continental completed 12 gross (5 net) operated and non-operated wells with first production in SCOOP in fourth quarter 2016.

For full-year 2016, the Company completed 71 gross (28 net) operated and non-operated wells with first production in SCOOP. In 2017, the Company plans to average five operated rigs in the play.

SCOOP Woodford Condensate Type Curve EUR Increased Again

Continental announced an additional 15% increase in the type curve EUR for SCOOP Woodford condensate wells to 2.3 MMBoe for a 7,500-foot lateral. This is the second increase in EUR since the Company implemented enhanced completion designs in the play.

At the new EUR, SCOOP condensate wells are expected to generate an impressive 80% rate of return at $55 oil WTI and $3.50 Mcf of gas. This assumes an average completed well cost of $10.3 million for a 7,500-foot lateral.

“As our teams optimize enhanced completions, we are continuing to see wells outperform their offsets,” said Gary Gould, Senior Vice President, Production and Resource Development. “Enhanced completions are a successful value driver for us not only in SCOOP, but in all of our plays.”

Two recent SCOOP Woodford initial 24-hour production test rates included:

- 3,547 Boe per day (26% oil) from an 8,600-foot lateral (Peppered Ranch 1-36-25XH);
- 3,463 Boe per day (29% oil) from a 10,000-foot lateral (Boatright 1-31-30XH).

SCOOP Woodford Oil Update

In early 2017 Continental completed the Emery 1R-9-16XH in the SCOOP Woodford oil window. The Emery flowed at an initial 24-hour production rate of 1,334 Boe per day (77% oil) from a 9,700-foot lateral and utilized shorter completion stage spacing.

As announced in November 2016, Continental completed the May unit density test in the SCOOP Woodford oil window. The test included five new wells and two parent wells in the Upper Woodford. To date, the seven wells have produced 934 MBoe (74% oil), and they continue to outperform the type curve.

SCOOP Springer: Resuming Activity

Continental has resumed drilling activity in the SCOOP Springer, which is located approximately 1,000 feet above the Woodford. The Company has approximately 200,000 net acres in the Springer and plans in 2017 to drill and complete five wells in the fairway to test the latest stimulation designs and longer laterals.

Bakken: Larger Enhanced Completions

Continental’s Bakken net production averaged 104,500 Boe per day in fourth quarter 2016. The Company completed 64 gross (16 net) operated and non-operated Bakken wells with first production during fourth quarter 2016, compared with a total 204 gross (47 net) operated and non-operated Bakken wells with first production for full-year 2016. The Company ended 2016 with a drilled-well inventory of 187 gross operated wells, including 12 gross operated wells with stimulation complete or in progress, but which did not have first sales in 2016.

Completion activity is accelerating in the first half of 2017, reflecting the addition of completion crews in the play in late 2016. The Company currently has five stimulation crews in the play and plans to increase to eight by mid-May. Continental has four operated drilling rigs working in the Bakken and plans to maintain that level through year end. The Company is targeting completing 148 Bakken gross operated wells with first production in 2017, and ending the year with 72 additional wells stimulated with first production in 2018.

The Company has continued to test various enhanced stimulation designs, along with more aggressive flowback and high-rate production lift. Completion testing has included proppant volumes of up to 2,000 pounds per foot, as well as the use of diverters. The completion designs in combination with more aggressive flowback procedures have increased initial 90-day production rates by approximately 35% for initial wells drilled in units, compared with the 980 MBoe EUR type curve the Company is targeting for its uncompleted well backlog.

Select initial 24-hour production test rates include:

- 2,718 Boe per day (85% oil) from a 10,200-foot lateral (Holstein Federal 13-25H); and
- 2,761 Boe per day (84% oil) from a 9,800-foot lateral (Charolais North Federal 1-31H1).

The Holstein Federal 13-25H, combined with the Rath Federal 5-22H and the Brangus North 1-2H2 reported last quarter, have produced the Company's three all-time highest 30-day Bakken rates.

2016 Proved Reserves Increase Despite Lower Commodity Prices

The Company announced proved reserves of 1.27 billion Boe at December 31, 2016, a 4% increase compared with year-end 2015 proved reserves. The 2016 increase was achieved despite lower SEC average commodity prices for the year. The 2016 average SEC oil price was $42.75 per barrel, 15% below the 2015 average price of $50.28 per barrel. The 2016 average SEC natural gas price was $2.49 per MMBtu, compared with $2.58 per MMBtu for 2015.

At December 31, 2016, Continental had a Standardized Measure of discounted future net cash flows of $5.51 billion. Continental's 2016 proved reserves had a net present value discounted at 10% (PV-10) of $6.65 billion. PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues of approximately $1.14 billion. Continental and others in the crude oil and natural gas industry use PV-10 as a measure to compare the relative size and value of proved reserves without regard to specific income tax characteristics.

Year-end 2016 proved reserves were 50% crude oil, 88% operated by the Company, and approximately 41% proved developed producing (PDP).

The Bakken accounted for 592 million Boe, or 46% of Continental's year-end 2016 proved reserves. The SCOOP Woodford and SCOOP Springer plays accounted for 472 MMBoe, or 37% of Continental's year-end 2016 proved reserves.

The STACK Meramec and STACK Woodford plays grew significantly in the past year, and at year end accounted for 161 MMBoe, or 13% of Continental's year-end 2016 proved reserves.

The Company had a total of 1,715 gross (963 net) proved undeveloped (PUD) locations at year-end 2016, with the Bakken accounting for 1,081 gross (600 net) PUD locations. SCOOP accounted for an additional 370 gross (250 net) PUD locations, while STACK accounted for 264 gross (113 net) PUD locations at year-end 2016.

"The impact of STACK on our proved reserves is only beginning to be realized," said Mr. Stark. "The play continues to expand, and at this time we believe it could add as much as 35% to our net unrisked resource potential."

Financial Update: Low Costs per Boe throughout 2016

"We were very pleased to finish 2016 in line with all aspects of our budget," said John Hart, Chief Financial Officer. "Production expense per Boe was down 15% from 2015, even with lower production for the year. This speaks directly to the performance of our operating teams and the premier quality of our assets.

"At year end, long-term debt was slightly under $6.6 billion, reflecting more than a $600 million reduction from peak debt levels in 2016, and leverage metrics continue to improve," he said. "We remain focused on spending within cash flow and plan to sell additional non-strategic assets to further reduce debt."

In fourth quarter 2016, Continental's average realized sales price excluding the effects of derivative positions was $42.23 per barrel of oil and $2.70 per Mcf of gas, or $30.64 per Boe. Based on realizations without the effect of derivatives, the Company's fourth quarter 2016 oil differential was $6.95 per barrel below the NYMEX daily average for the period. The realized wellhead natural gas price for the quarter was on average $0.28 per Mcf below the average NYMEX Henry Hub benchmark price.

Production expense per Boe was $3.60 for fourth quarter 2016, compared with $3.86 per Boe for fourth quarter 2015. Other select operating costs and expenses for fourth quarter 2016 included production taxes of 6.4% of oil and natural gas sales; DD&A of $20.11 per Boe; and G&A of $2.93 per Boe. On a full-year basis, these expense categories were within guidance.

As of December 31, 2016, Continental's balance sheet included $16.6 million in cash and cash equivalents and $905 million of borrowings against the Company's revolving credit facility. Continental had approximately $1.84 billion in available borrowing capacity under its revolving credit facility as of December 31, 2016, a decrease from the October 31, 2016 level of $2.45 billion, due to borrowings incurred to fund the November redemption of $600 million of Senior Notes.

Continental's 2017 guidance remains as announced on January 25, 2017 and can be found at the conclusion of this press release.

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

	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
Average daily production:				
Crude oil (Bbl per day)	116,486	145,576	128,005	146,622
Natural gas (Mcf per day)	560,251	476,160	533,442	450,558
Crude oil equivalents (Boe per day)	209,861	224,936	216,912	221,715
Average sales prices, excluding effect from derivatives:				
Crude oil ($/Bbl)	$42.23	$34.23	$35.51	$40.50
Natural gas ($/Mcf)	$2.70	$2.07	$1.87	$2.31
Crude oil equivalents ($/Boe)	$30.64	$26.57	$25.55	$31.48
Production expenses ($/Boe)	$3.60	$3.86	$3.65	$4.30
Production taxes (% of oil and gas revenues)	6.4%	7.8%	7.0%	7.8%
DD&A ($/Boe)	$20.11	$22.20	$21.54	$21.57
Total general and administrative expenses ($/Boe) (1)	$2.93	$2.24	$2.14	$2.34
Net income (loss) (in thousands)	$27,670	($139,677)	($399,679)	($353,668)
Diluted net income (loss) per share	$0.07	($0.38)	($1.08)	($0.96)
Adjusted net loss (non-GAAP) (in thousands) (2)	($27,416)	($86,644)	($326,648)	($115,525)
Adjusted diluted net loss per share (non-GAAP) (2)	($0.07)	($0.23)	($0.88)	($0.31)
Net cash provided by operating activities	$262,031	$441,609	$1,125,919	$1,857,101
EBITDAX (non-GAAP) (in thousands) (2)	$652,382	$420,239	$1,881,889	$1,978,896

(1) 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 $2.21, $1.68, $1.53, and $1.70 for 4Q 2016, 4Q 2015, FY 2016, and FY 2015, respectively. Non-cash equity compensation expense per Boe was $0.72, $0.56, $0.61, and $0.64 for 4Q 2016, 4Q 2015, FY 2016, and FY 2015, respectively.

(2) Adjusted net loss, adjusted diluted net loss per share, and EBITDAX represent non-GAAP financial measures. These measures should not be considered as an alternative to, or more meaningful than, net income (loss), diluted net income (loss) per share, or net cash provided by operating activities as determined in accordance with U.S. GAAP. Further information about these non-GAAP financial measures as well as reconciliations of adjusted net loss, adjusted diluted net loss per share, and EBITDAX to the most directly comparable U.S. GAAP financial measures are provided subsequently under the header *Non-GAAP Financial Measures* .

Fourth Quarter and Full-Year Earnings Conference Call

Continental plans to host a conference call to discuss fourth quarter and full-year results on Thursday, February 23, 2017, 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 www.CLR.com or by phone:

Time and date: 12 p.m. ET, Thursday, February 23, 2017
Dial in: 844-309-6572
Intl. dial in: 484-747-6921

Pass code:	26962968

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:	26962968

Continental plans to publish a fourth quarter and full-year 2016 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on February 23, 2017.

Upcoming Conferences

Members of Continental's management team plan to participate in the following investment conferences:

March 2-3, 2017	17th Annual Simmons/Piper Jaffray Energy Conference, Las Vegas
March 6-7, 2017	Raymond James 38th Annual Institutional Investor Conference, Orlando
March 7, 2017	Evercore ISI Energy/Power Summit 2017, Houston
March 27-28, 2017	Scotia Howard Weil 45th Annual Energy Conference, New Orleans

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 one of the largest producers 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 2017, the Company will celebrate 50 years of operations. For more information, please visit 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, 2015, and once filed, for the year ended December 31, 2016, 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
Consolidated Statements of Income (Loss)

	Three months ended December 31,		Year ended December 31,	
	2016	2015	2016	2015
Revenues:	In thousands, except per share data			
Crude oil and natural gas sales	$ 591,764	$ 551,380	$ 2,026,958	$ 2,552,531
Gain (loss) on crude oil and natural gas derivatives, net	(47,382)	16,540	(71,859)	91,085
Crude oil and natural gas service operations	5,307	7,560	25,174	36,551
Total revenues	549,689	575,480	1,980,273	2,680,167
Operating costs and expenses:				
Production expenses	69,544	80,185	289,289	348,897
Production taxes and other expenses	38,172	43,048	142,388	200,637
Exploration expenses	8,246	4,732	16,972	19,413
Crude oil and natural gas service operations	2,162	2,292	11,386	17,337
Depreciation, depletion, amortization and accretion	388,321	460,778	1,708,744	1,749,056
Property impairments	34,564	81,001	237,292	402,131
General and administrative expenses	56,537	46,478	169,580	189,846
Net gain on sale of assets and other	(203,154)	(218)	(307,844)	(23,149)
Total operating costs and expenses	394,392	718,296	2,267,807	2,904,168
Income (loss) from operations	155,297	(142,816)	(287,534)	(224,001)
Other income (expense):				
Interest expense	(75,613)	(80,175)	(320,562)	(313,079)
Loss on extinguishment of debt	(26,055)	-	(26,055)	-
Other	519	520	1,697	1,995
	(101,149)	(79,655)	(344,920)	(311,084)
Income (loss) before income taxes	54,148	(222,471)	(632,454)	(535,085)
Provision (benefit) for income taxes	26,478	(82,794)	(232,775)	(181,417)
Net income (loss)	$ 27,670	$ (139,677)	$ (399,679)	$ (353,668)
Basic net income (loss) per share	$ 0.07	$ (0.38)	$ (1.08)	$ (0.96)
Diluted net income (loss) per share	$ 0.07	$ (0.38)	$ (1.08)	$ (0.96)

Continental Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31,2016	December 31, 2015
	In thousands	
Assets		
Current assets	$ 913,233	$ 822,339
Net property and equipment [1]	12,881,227	14,063,328
Other noncurrent assets	17,316	34,141
Total assets	$ 13,811,776	$ 14,919,808
Liabilities and shareholders' equity		
Current liabilities	$ 932,393	$ 923,028
Long-term debt, net of current portion	6,577,697	7,115,644
Other noncurrent liabilities	1,999,690	2,212,236
Total shareholders' equity	4,301,996	4,668,900
Total liabilities and shareholders' equity	$ 13,811,776	$ 14,919,808

(1) Balance is net of accumulated depreciation, depletion and amortization of $7.65 billion and $6.45 billion as of December 31, 2016 and December 31, 2015, respectively.

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

	Three months ended December 31,		Year ended December 31,	
In thousands	2016	2015	2016	2015
Net income (loss)	$ 27,670	$ (139,677)	$ (399,679)	$ (353,668)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash expenses	369,093	477,006	1,687,814	1,982,147
Changes in assets and liabilities	(134,732)	104,280	(162,216)	228,622
Net cash provided by operating activities	262,031	441,609	1,125,919	1,857,101
Net cash (used in) provided by investing activities	17,256	(448,548)	(532,965)	(3,046,247)
Net cash (used in) provided by financing activities	(282,132)	3,492	(587,773)	1,187,189
Effect of exchange rate changes on cash	(8)	(2,045)	(1)	(10,961)
Net change in cash and cash equivalents	(2,853)	(5,492)	5,180	(12,918)
Cash and cash equivalents at beginning of period	19,496	16,955	11,463	24,381
Cash and cash equivalents at end of period	$ 16,643	$ 11,463	$ 16,643	$ 11,463

Non-GAAP Financial Measures

PV-10

The Company's PV-10 value, a non-GAAP financial measure, is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 generally differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. At December 31, 2016, the Company's PV-10 totaled approximately $6.65 billion. The Standardized Measure of discounted future net cash flows was approximately $5.51 billion at December 31, 2016, representing a $1.14 billion difference from PV-10 due to the effect of deducting estimated future income taxes in arriving at the Standardized Measure. The Company believes the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of crude oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of the Company's proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Company's crude oil and natural gas properties.

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. EBITDAX is not a measure of net income or operating cash flows 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 operating cash flows 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 operating cash flows 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.

In thousands	Three months ended December 31, 2016	Three months ended December 31, 2015	Year ended December 31, 2016	Year ended December 31, 2015
Net income (loss)	$ 27,670	$ (139,677)	$ (399,679)	$ (353,668)
Interest expense	75,613	80,175	320,562	313,079
Provision (benefit) for income taxes	26,478	(82,794)	(232,775)	(181,417)
Depreciation, depletion, amortization and accretion	388,321	460,778	1,708,744	1,749,056
Property impairments	34,564	81,001	237,292	402,131
Exploration expenses	8,246	4,732	16,972	19,413
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	45,331	(16,540)	67,099	(91,085)
Total cash received on derivatives, net	6,281	21,019	89,522	69,553
Non-cash (gain) loss on derivatives, net	51,612	4,479	156,621	(21,532)
Non-cash equity compensation	13,823	11,545	48,097	51,834
Loss on extinguishment of debt	26,055	-	26,055	-
EBITDAX (non-GAAP)	$ 652,382	$ 420,239	$ 1,881,889	$ 1,978,896

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

In thousands	Three months ended December 31, 2016	Three months ended December 31, 2015	Year ended December 31, 2016	Year ended December 31, 2015
Net cash provided by operating activities	$ 262,031	$ 441,609	$ 1,125,919	$ 1,857,101
Current income tax provision (benefit)	(22,941)	2	(22,939)	24
Interest expense	75,613	80,175	320,562	313,079
Exploration expenses, excluding dry hole costs	3,613	4,535	12,106	11,032
Gain on sale of assets, net	201,315	218	304,489	23,149
Tax benefit (deficiency) from stock-based compensation	(368)	-	(9,828)	13,177
Other, net	(1,613)	(2,020)	(10,636)	(10,044)
Changes in assets and liabilities	134,732	(104,280)	162,216	(228,622)
EBITDAX (non-GAAP)	$ 652,382	$ 420,239	$ 1,881,889	$ 1,978,896

Adjusted earnings and adjusted earnings 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. 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 a substitute for 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 tables reconcile 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 December 31,			
	2016		2015	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net income (loss) (GAAP)	$ 27,670	$ 0.07	$ (139,677)	$ (0.38)
Adjustments:				
Non-cash loss on derivatives	51,612		4,479	
Property impairments	34,564		81,001	
Gain on sale of assets	(201,315)		(218)	
Loss on extinguishment of debt	26,055		-	
Total tax effect of adjustments	33,998		(32,229)	
Total adjustments, net of tax	(55,086)	(0.14)	53,033	0.15
Adjusted net loss (non-GAAP)	$ (27,416)	$ (0.07)	$ (86,644)	$ (0.23)
Weighted average diluted shares outstanding	370,539		369,662	
Adjusted diluted net loss per share (non-GAAP)	$ (0.07)		$ (0.23)	

	Year ended December 31,			
	2016		2015	
In thousands, except per share data	$	Diluted EPS	$	Diluted EPS
Net loss (GAAP)	$ (399,679)	$ (1.08)	$ (353,668)	$ (0.96)
Adjustments:				
Non-cash (gain) loss on derivatives	156,621		(21,532)	
Property impairments	237,292		402,131	
Gain on sale of assets	(304,489)		(23,149)	
Loss on extinguishment of debt	26,055		-	
Total tax effect of adjustments	(42,448)		(119,307)	
Total adjustments, net of tax	73,031	0.20	238,143	0.65
Adjusted net loss (non-GAAP)	$ (326,648)	$ (0.88)	$ (115,525)	$ (0.31)
Weighted average diluted shares outstanding	370,380		369,540	
Adjusted diluted net loss per share (non-GAAP)	$ (0.88)		$ (0.31)	

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.
2017 Guidance
As of February 22, 2017

	2017
Full year average production	220,000 to 230,000 Boe per day
Exit rate average production	250,000 to 260,000 Boe per day
Capital expenditures (non-acquisition)	$1.95 billion
Operating Expenses:	
Production expense per Boe	$3.50 to $4.00
Production tax (% of oil & gas revenue)	6.75% to 7.25%
Cash G&A expense per Boe[(1)]	$1.50 to $2.00
Non-cash equity compensation per Boe	$0.60 to $0.70
DD&A per Boe	$19.00 to $22.00
Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	($6.50) to ($7.50)
Henry Hub natural gas (per Mcf)	$0.10 to ($0.40)
Income tax rate	38%
Deferred taxes	90% to 95%

(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 $2.10 to $2.70 per Boe.