Continental Resources Reports Third Quarter 2015 Results

New Wells in STACK: Ladd 1-8-5XH Flows 2,181 Barrels of Oil Equivalent (Boe) per Day (79% Oil), and Marks 1-9-4XH Flows 994 Boe per Day (73% Oil)
Positive Revisions to 2015 Guidance: Lower Cash Costs and Increased Production
Debt and Credit Facility Changes Reduce Borrowing Costs While Increasing Liquidity
Production for Third Quarter 2015 Averaged 228,278 Boe per Day

OKLAHOMA CITY, Nov. 4, 2015 /PRNewswire/ -- Continental Resources, Inc. (NYSE: CLR) (Continental or the Company) today announced third quarter 2015 operating and financial results.

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Continental reported a net loss of $82.4 million, or $0.22 per diluted share, for third quarter 2015. Adjusted net loss for third quarter 2015 was $43.5 million, or $0.12 per diluted share.

EBITDAX for third quarter 2015 was $472.2 million, compared with EBITDAX of $947.6 million for third quarter 2014. Definitions and reconciliations of adjusted net income and net loss, adjusted earnings 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.

"This was another solid quarter's performance," said Harold Hamm, Chairman and Chief Executive Officer. "As expected, we continue to deliver on cost controls and operating efficiencies, while maintaining our exploration focus. We continued in the third quarter to improve across the board in the key metrics we control – faster drill times, lower completed well costs, and strong well results from enhanced completions. On the financial side, we remain focused on balancing capital expenditures with cash flow."

"We are very pleased with the performance of our two recent completions in STACK," said Jack Stark, President and Chief Operating Officer. "Based on early results and our geologic model, we expect STACK will add significant value to the Company and to our shareholders."

2015 Guidance Update; Increased Production at Lower Cost

Based on continued strong well performance through the third quarter, the Company is increasing its production growth guidance to a range of 24% to 26% for 2015, compared with the earlier range of 19% to 23% growth over the previous year. Continental expects non-acquisition capital expenditures for fourth quarter 2015 will be in the range of $350 million to $400 million.

Continental is lowering 2015 guidance for production expense, general and administrative (G&A) expense and non-cash equity compensation expense per barrel of oil equivalent (Boe) of production, reflecting increased operating efficiencies companywide. Overall, the guidance on select costs for 2015 has been reduced by a total of $0.85 to $1.05 per Boe of production. Production expense is now expected to be in a range of $4.00 to $4.50 per Boe for the year, production tax is expected to be in a range of 7.5% to 8.0% of oil and gas revenue, and G&A expense is expected to be in a range of $1.70 to $2.00 per Boe. Non-cash equity compensation is expected to be $0.65 to $0.75 per Boe for the year. In addition, Continental is tightening its 2015 guidance range for oil differentials to $7.00 to $9.00 per barrel below the NYMEX daily average compared with the previous range of $7.00 to $10.00 per barrel.

	December 2014 Guidance	August 2015 Guidance	Updated 2015 Guidance

Production growth	16% to 20%	19% to 23%	24% to 26%
Production expense per Boe	$5.50 to $6.00	$4.75 to $5.25	$4.00 to $4.50
Production tax (% of oil & gas revenue)	7.5% to 8.5%	7.5% to 8.5%	7.5% to 8.0%
G&A expense per Boe	$2.00 to $2.50	$1.75 to $2.25	$1.70 to $2.00
Non-cash equity compensation per Boe	$0.75 to $0.95	$0.70 to $0.80	$0.65 to $0.75
Avg. price differential to NYMEX WTI crude oil (per barrel of oil)	($7.00) to ($10.00)	($7.00) to ($10.00)	($7.00) to ($9.00)

A table with the Company's full 2015 guidance can be found at the conclusion of this release.

Continental plans to publish 2016 guidance in late December 2015 or early January 2016.

Cost Reductions and Efficiency Improvements

Continental's drilling and completion costs for most operated wells have declined on average approximately 25% since year-end 2014, due to lower service costs and operational efficiency gains. For the Bakken play, the current estimated drilling and completion cost has decreased to $7.0 million per operated well, compared with $9.6 million per operated well at year-end 2014. At these lower costs and targeted estimated ultimate recovery (EUR) of 800 MBoe per well, the Company has cut its finding cost in half since year-end 2014, doubling its capital efficiency. For the Woodford condensate play, the current estimated drilling and completion cost has decreased to $9.6 million per operated well, compared with $12.2 million per operated well at year-end 2014, based on a 7,500-foot lateral in the Company's development areas of the South Central Oklahoma Oil Province (SCOOP).

In the Northern Region during third quarter 2015, the Bakken drilling team set multiple new Continental performance records. For example, the Company reduced average drilling time for spud-to-total-depth (TD) by 15%, compared to the average for the first quarter. The average spud-to-TD time in third quarter 2015 was 15.0 days for a two-mile lateral, compared to 17.6 days in the first quarter and 16.6 days in the second quarter of this year. The most significant efficiency achievement came in average days to drill horizontal laterals. The Bakken drilling team in third quarter 2015 set several new lateral drilling records, the most recent drilled being a 9,495-foot lateral in 2.4 days. The Bakken team continues to drive down lease operating expenses, with per-well lease operating expense down 30% in third quarter 2015, compared with fourth quarter 2014. Annualized, this represents approximately $40 million of savings to Continental.

In the Southern Region during third quarter 2015, the drilling team also continued to set new Continental records, demonstrating the future potential for efficiency gains throughout the SCOOP and STACK plays. Leveraging the knowledge gained on the Poteet and Honeycutt density pilots, the SCOOP team was able to drill the Vanarkel density pilot in half the time per well of the first multi-well project.

On the Newy 8-25-24-13XH well, the SCOOP team set a Continental drilling record for spud-to-TD in 47 days, a 30% reduction in drilling time compared to nearby wells. This well also set a new Oklahoma depth record with a total measured depth of 26,196 feet. On the Kalsu 1-35-2-11XH, the Northwest Cana drilling team set a new Continental record for its Joint Development Agreement (JDA) area, drilling spud-to-TD in 40 days, a 50% reduction from nearby wells.

Production

Third quarter 2015 net production totaled 21.0 million Boe, or 228,278 Boe per day, a sequential increase of 1% from second quarter 2015 and 25% higher than third quarter 2014. Total net production for the third quarter included 147,472 barrels of oil (Bo) per day (65% of production) and 484.8 million cubic feet (MMcf) of natural gas per day (35% of production). In third quarter 2015, sales volumes also totaled 21.0 million Boe, consistent with production for the quarter.

Fourth quarter 2015 daily production is expected to decline compared with third quarter. Continental expects to exit December 2015 with production of approximately 210,000 Boe per day. Continental is currently operating 23 rigs, including 8 rigs in the Bakken and 15 rigs in Oklahoma. The Company has recently added two completion crews in Oklahoma, bringing the total crew count to three. In the Bakken, Continental currently has no completion crews active.

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

Boe per day	3Q 2015	2Q 2015	3Q 2014	YTD 2015	YTD 2014
North Region:					
North Dakota Bakken	123,560	127,872	106,224	124,139	94,966
Montana Bakken	12,049	13,116	15,380	13,239	14,334
Red River Units	12,110	12,669	13,749	12,574	14,003
Other	992	1,835	725	1,171	837
South Region:					
SCOOP	69,136	62,546	36,346	60,592	33,350
NW Cana	6,629	4,410	4,957	4,836	5,286
Arkoma	2,056	2,112	2,494	2,097	2,552
Other	1,746	1,987	2,460	1,982	2,368
Total	228,278	226,547	182,335	220,630	167,696

STACK

The Company continues to de-risk its leasehold position in the STACK play in Oklahoma.

Continental recently completed its second and third STACK wells, the Ladd 1-8-5XH and the Marks 1-9-4XH. Both wells targeted the Meramec reservoir in Blaine County, northwest of the Ludwig 1-22-15XH, the Company's initial STACK well. The Ladd tested at an initial production rate of 2,181 Boe per day (79% oil) from a 9,742-foot lateral. The Marks tested at an initial production rate of 994 Boe per day (73% oil) from a 10,092-foot lateral.

Production from the previously announced Ludwig 1-22-15XH well continued to strengthen after it was initially reported last quarter, resulting in a 24-hour peak production rate of 2,782 Boe per day (76% oil).

"Continental and others continue to successfully expand the productive footprint of STACK west into Blaine, Dewey and Custer counties, where the STACK reservoirs are thicker, over-pressured, and are delivering superior production rates," said Mr. Stark. "More than 95% of our acreage lies in these counties, and approximately 60% is held by production."

The Company is drilling three additional STACK wells, with one well waiting on completion and expects to spud another two to three wells before year end. Continental has 146,300 net acres in the play. Continental currently has three operated drilling rigs in STACK.

SCOOP Woodford and Springer

In third quarter 2015, total SCOOP net production averaged 69,136 Boe per day, an increase of 11% sequentially compared with second quarter 2015 and 90% compared with third quarter 2014. SCOOP production represented 30% of the Company's total production in third quarter 2015, compared with 20% of Company production for third quarter 2014.

During third quarter 2015, the Company completed 11 net (34 gross) operated and non-operated wells, while operating an average of eight rigs in SCOOP. Continental's activities in SCOOP are primarily focused on the

Woodford formation and Springer formation, which is located approximately 1,000 to 1,500 feet above the Woodford. Current drilling is focused on the Woodford formation.

Continental currently has 28 gross operated wells drilled and waiting on first production in SCOOP Woodford and Springer, compared to 22 at the end of second quarter 2015, reflecting the deferral of completion activities starting in third quarter 2015. The Company expects this total to increase to approximately 35 gross operated wells drilled and waiting on first production by year-end 2015.

SCOOP Woodford

In third quarter 2015, SCOOP Woodford net production averaged 57,933 Boe per day, a 9% increase sequentially over second quarter 2015. In third quarter 2015, the Company completed five net (27 gross) operated and non-operated Woodford wells in the play.

Select initial test rates from recent SCOOP Woodford operated wells in Grady County include:

- The Early 1-32-29XH well tested at 1,448 Boe per day (66% oil), from 7,655 feet of completed lateral;
- The Triple H 1-30H tested at 1,037 Boe per day (68% oil), from 4,496 feet of completed lateral;
- The Gentry 1-11-2XH tested at 17,018 Mcfe per day (85% gas), from 10,128 feet of completed lateral; and
- The Silver Stratton 1-6-31XH tested at 13,168 Mcfe per day (58% gas), from 10,036 feet of completed lateral.

SCOOP Springer

In third quarter 2015, SCOOP Springer net production averaged 11,203 Boe per day, an increase of 22% sequentially over second quarter 2015. The Company completed six net (seven gross) operated and non-operated Springer wells in third quarter 2015.

Select initial test rates from recent SCOOP Springer operated wells in Grady County include:

- The Walters West 1-34H well tested at 1,476 Boe per day (78% oil) from 4,669 feet of completed lateral;
- The Sawyer 1-23H well tested at 1,343 Boe per day (83% oil) from 4,718 feet of completed lateral; and
- The Jantz Family 1-33H well tested at 1,210 Boe per day (77% oil) from 4,377 feet of completed lateral.

Northwest Cana Joint Development Agreement

In third quarter 2015, Northwest Cana net production averaged 6,629 Boe per day. The Company completed two net (four gross) operated and non-operated wells in the JDA area in Blaine and Dewey counties in the third quarter.

Select initial test rates from recent operated wells include:

- The Ireta 1-4-9XH well had a record initial production test rate of 16,659 Mcfe per day (100% gas) from 10,188 feet of completed lateral; and
- The Hook 1-21H well tested at 9,088 Mcfe per day (100% gas) from 4,856 feet of completed lateral.

Continental currently has five operated drilling rigs in the JDA area.

Bakken

Continental's Bakken production averaged 135,609 Boe per day in the third quarter of 2015, an increase of 12% compared with third quarter 2014 and a decrease of 4% compared with second quarter 2015. The Company completed 35 net (160 gross) operated and non-operated Middle Bakken and Three Forks wells during third quarter 2015.

Continental currently has 123 gross operated wells drilled and waiting on first production in the Bakken, compared to 95 at the end of second quarter 2015. This reflects the deferral of completion activities starting in third quarter 2015 and completed wells that have not commenced production. The Company expects to decrease this total to approximately 115 gross operated wells drilled and waiting on first production at year-end 2015.

Financial Update

In third quarter 2015, Continental's average realized sales price excluding the effects of derivative positions was $38.95 per Bo and $2.23 per Mcf, or $29.90 per Boe. Settlements of matured commodity derivative positions generated a $0.27 gain per Mcf of natural gas, resulting in a net gain on matured derivatives of $11.9 million, or $0.57 per Boe, for third quarter 2015. Based on realizations without the effect of derivatives, the Company's third quarter 2015 oil differential was $7.54 per barrel below the NYMEX daily average for the period. The realized natural gas price differential for third quarter 2015 was a negative $0.54 per Mcf.

For third quarter 2015, production expense was $4.00 per Boe sold, compared with $4.39 per Boe for second quarter 2015. Other select operating costs and expenses for third quarter 2015 included production taxes of 7.6% on oil and natural gas sales; depreciation, depletion, amortization and accretion (DD&A) expense of $21.36 per Boe; cash G&A expense of $1.95 per Boe; and equity compensation expense of $0.61 per Boe.

Non-acquisition capital expenditures for third quarter 2015 totaled approximately $540.0 million. Total capital expenditures for the quarter included $477.8 million in exploration and development drilling, $28.4 million in leasehold and seismic, and $33.8 million in workovers, recompletions and other. As noted earlier, Continental expects non-acquisition capital expenditures for fourth quarter 2015 will be in the range of $350 million to $400 million.

As of September 30, 2015, Continental's balance sheet included approximately $17.0 million in cash and cash equivalents, and $7.1 billion in long-term debt.

"Today we increased the commitments on our revolving credit facility to $2.75 billion and termed out $500 million of revolving debt with a three-year unsecured term note at a current interest rate 1/8% lower than the revolver," said John Hart, Senior Vice President, Chief Financial Officer and Treasurer. "These transactions reduce overall borrowing costs and demonstrate our ability to provide additional liquidity. After these transactions, we have $880 million of borrowings against the Company's unsecured credit facility, leaving availability of approximately $1.9 billion."

He continued, "I want to emphasize these transactions do not indicate plans to grow debt. Our focus remains on balancing capital expenditures with cash flows, and therefore not incurring additional debt. If low commodity prices persist in 2016, we have additional Bakken rigs coming off contract, so we can further reduce capital expenditures. We are concentrated on balance sheet strength and optionality, in preparation for a more favorable, long-term commodity price environment."

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 September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Average daily production:				
Crude oil (Bbl per day)	147,472	127,788	146,975	116,954
Natural gas (Mcf per day)	484,834	327,287	441,930	304,453
Crude oil equivalents (Boe per day)	228,278	182,335	220,630	167,696
Average sales prices, excluding effect from derivatives:				
Crude oil ($/Bbl)	$38.95	$85.49	$42.60	$89.02
Natural gas ($/Mcf)	$2.23	$5.10	$2.39	$5.80
Crude oil equivalents ($/Boe)	$29.90	$69.08	$33.18	$72.52
Production expenses ($/Boe)	$4.00	$5.80	$4.45	$5.69
Production taxes (% of oil and gas revenues)	7.6%	8.3%	7.8%	8.1%
DD&A ($/Boe)	$21.36	$21.65	$21.36	$21.17
General and administrative expenses ($/Boe)	$1.95	$1.82	$1.71	$2.08
Non-cash equity compensation ($/Boe)	$0.61	$0.80	$0.67	$0.87
Net income (loss) (in thousands)	($82,423)	$533,521	($213,992)	$863,293
Diluted net income (loss) per share	($0.22)	$1.44	($0.58)	$2.33
Adjusted net income (loss) (in thousands) [(1)]	($43,512)	$300,961	($28,881)	$850,402
Adjusted diluted net income (loss) per share [(1)]	($0.12)	$0.81	($0.08)	$2.29
EBITDAX (in thousands) [(1)]	$472,221	$947,635	$1,558,656	$2,590,980

(1) Adjusted net income (loss), adjusted diluted net income (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 operating cash flows as determined in accordance with U.S. GAAP. Further information about these non-GAAP financial measures as well as reconciliations of adjusted net income (loss), adjusted diluted net income (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*.

Third Quarter Conference Call

Continental plans to host a conference call to discuss third quarter results on Thursday, November 5, 2015, 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, November 5, 2015
Dial-in:	855-291-6799
Intl. dial-in:	315-625-3058
Conference ID:	10361462

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
Conference ID:	10361462

Continental plans to publish a third quarter 2015 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on November 5, 2015.

Upcoming Conferences

Members of Continental's management team will be participating in the following upcoming investment conferences:

November 9, 2015	Robert W. Baird & Co.'s 2015 Industrial Conference; Chicago
November 10, 2015	Bank of America Merrill Lynch 2015 Global Energy Conference; Miami
December 2, 2015	Cowen and Company's 5th Annual Ultimate Energy Conference; NYC
December 9, 2015	Capital One 10th Annual Energy Conference; New Orleans

December 8, 2015	Capital One 10th Annual Energy Conference, New Orleans

Instructions regarding how to access the live and replay webcast for the Bank of America Merrill Lynch presentation and presentation materials for all conferences mentioned above will be available on the Company's website at www.CLR.com on or prior to the day of the presentations.

About Continental Resources

Continental Resources (NYSE: CLR) is a top independent oil producer in the lower 48 United States 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 and Northwest Cana plays. With a focus on the exploration and production of oil, Continental has unlocked the technology and resources vital to American energy independence and is a strong free market advocate in favor of lifting the domestic crude oil export ban. In 2015, the Company will celebrate 48 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, 2014, 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 September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Revenues:	*In thousands, except per share data*			
Crude oil and natural gas sales	$ 628,457	$ 1,160,281	$ 2,001,151	$ 3,300,699
Gain on derivative instruments, net	46,527	473,999	74,545	171,801
Crude oil and natural gas service operations	7,685	11,048	28,991	31,418
Total revenues	682,669	1,645,328	2,104,687	3,503,918
Operating costs and expenses:				
Production expenses	84,036	97,374	268,712	258,781
Production taxes and other expenses	47,682	97,399	157,589	272,726
Exploration expenses	232	13,514	14,680	29,532
Crude oil and natural gas service operations	4,059	4,337	15,045	18,390
Depreciation, depletion, amortization and accretion	448,809	363,677	1,288,278	963,409
Property impairments	96,697	85,561	321,130	223,085
General and administrative expenses	53,798	43,980	143,368	134,435
(Gain) loss on sale of assets, net	(288)	(5,411)	(22,930)	952
Total operating costs and expenses	735,025	700,431	2,185,872	1,901,310

Income (loss) from operations	(52,356)	944,897	(81,185)	1,602,608
Other income (expense):				
Interest expense	(79,399)	(73,912)	(232,904)	(209,728)
Loss on extinguishment of debt	-	(24,517)	-	(24,517)
Other	588	393	1,474	1,945
	(78,811)	(98,036)	(231,430)	(232,300)
Income (loss) before income taxes	(131,167)	846,861	(312,615)	1,370,308
Provision (benefit) for income taxes	(48,744)	313,340	(98,623)	507,015
Net income (loss)	$ (82,423)	$ 533,521	$ (213,992)	$ 863,293
Basic net income (loss) per share	$ (0.22)	$ 1.45	$ (0.58)	$ 2.34
Diluted net income (loss) per share	$ (0.22)	$ 1.44	$ (0.58)	$ 2.33

Continental Resources, Inc. and Subsidiaries				
Unaudited Condensed Consolidated Balance Sheets				
	September 30, 2015		December 31, 2014	
Assets	*In thousands*			
Current assets	$	986,908	$	1,389,601
Net property and equipment [1]		14,173,563		13,635,852
Other noncurrent assets[2]		45,406		50,580
Total assets	$	15,205,877	$	15,076,033
Liabilities and shareholders' equity				
Current liabilities	$	1,149,917	$	1,952,013
Long-term debt, net of current portion [2]		7,108,702		5,926,800
Other noncurrent liabilities		2,148,681		2,229,376
Total shareholders' equity		4,798,577		4,967,844
Total liabilities and shareholders' equity	$	15,205,877	$	15,076,033

(1)	Balance is net of accumulated depreciation, depletion and amortization of $6.04 billion and $4.68 billion as of September 30, 2015 and December 31, 2014, respectively.
(2)	Balances at December 31, 2014 have been retroactively adjusted to reflect the Company's June 2015 adoption of Accounting Standards Update 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs, which resulted in the reclassification of $69.0 million of unamortized debt issuance costs at December 31, 2014 from "Other noncurrent assets" to a reduction of "Long-term debt, net of current portion".

Continental Resources, Inc. and Subsidiaries								
Unaudited Condensed Consolidated Statements of Cash Flows								
	Three months ended September 30,				Nine months ended September 30,			
In thousands	2015		2014		2015		2014	
Net income (loss)	$	(82,423)	$	533,521	$	(213,992)	$	863,293
Adjustments to reconcile net income (loss) to net cash provided by operating activities:								
Non-cash expenses		465,606		328,395		1,505,141		1,509,093
Changes in assets and liabilities		115,497		(16,518)		124,343		(94,535)
Net cash provided by operating activities		498,680		845,398		1,415,492		2,277,851
Net cash used in investing activities		(634,396)		(1,148,973)		(2,597,699)		(3,226,260)
Net cash provided by financing activities		132,031		(321,098)		1,183,697		1,072,217
Effect of exchange rate changes on cash		(4,818)		-		(8,916)		-

Net change in cash and cash equivalents	(8,503)	(624,673)	(7,426)	123,808
Cash and cash equivalents at beginning of period	25,458	776,963	24,381	28,482
Cash and cash equivalents at end of period	$ 16,955	$ 152,290	$ 16,955	$ 152,290

Non-GAAP Financial Measures

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.

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2015	2014	2015	2014
Net income (loss)	$ (82,423)	$ 533,521	$ (213,992)	$ 863,293
Interest expense	79,399	73,912	232,904	209,728
Provision (benefit) for income taxes	(48,744)	313,340	(98,623)	507,015
Depreciation, depletion, amortization and accretion	448,809	363,677	1,288,278	963,409
Property impairments	96,697	85,561	321,130	223,085
Exploration expenses	232	13,514	14,680	29,532
Impact from derivative instruments:				
Total gain on derivatives, net	(46,527)	(473,999)	(74,545)	(171,801)
Total cash (paid) received on derivatives, net	11,917	190	48,534	(97,217)
Non-cash gain on derivatives, net	(34,610)	(473,809)	(26,011)	(269,018)
Non-cash equity compensation	12,861	13,402	40,290	39,419
Loss on extinguishment of debt	-	24,517	-	24,517
EBITDAX	$ 472,221	$ 947,635	$ 1,558,656	$ 2,590,980

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

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2015	2014	2015	2014
Net cash provided by operating activities	$ 498,680	$ 845,398	$ 1,415,492	$ 2,277,851

Current income tax provision (benefit)	12	(826)	22	2,278
Interest expense	79,399	73,912	232,904	209,728
Exploration expenses, excluding dry hole costs	51	8,755	6,497	20,390
Gain (loss) on sale of assets, net	288	5,411	22,930	(952)
Excess tax benefit from stock-based compensation	13,177	-	13,177	-
Other, net	(3,889)	(1,533)	(8,023)	(12,850)
Changes in assets and liabilities	(115,497)	16,518	(124,343)	94,535
EBITDAX	$ 472,221	$ 947,635	$ 1,558,656	$ 2,590,980

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 on a recurring, comparable basis from period to period. 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 September 30,			
	2015		2014	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (loss) (GAAP)	$ (82,423)	$ (0.22)	$ 533,521	$ 1.44
Adjustments, net of tax:				
Non-cash gain on derivatives, net	(21,458)	(0.06)	(298,500)	(0.81)
Property impairments	60,543	0.16	53,903	0.15
Gain on sale of assets, net	(174)	-	(3,409)	(0.01)
Loss on extinguishment of debt	-	-	15,446	0.04
Adjusted net income (loss) (Non-GAAP)	$ (43,512)	$ (0.12)	$ 300,961	$ 0.81
Weighted average diluted shares outstanding	369,599		370,528	
Adjusted diluted net income (loss) per share (Non-GAAP)	$ (0.12)		$ 0.81	

	Nine months ended September 30,			
	2015		2014	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (loss) (GAAP)	$(213,992)	$ (0.58)	$ 863,293	$ 2.33
Adjustments, net of tax:				
Non-cash gain on derivatives, net	(16,126)	(0.04)	(169,481)	(0.46)
Property impairments	215,451	0.58	140,544	0.38
(Gain) loss on sale of assets, net	(14,214)	(0.04)	600	-
Loss on extinguishment of debt	-	-	15,446	0.04
Adjusted net income (loss) (Non-GAAP)	$ (28,881)	$ (0.08)	$ 850,402	$ 2.29
Weighted average diluted shares outstanding	369,499		370,632	
Adjusted diluted net income (loss) per share (Non-GAAP)	$ (0.08)		$ 2.29	

Continental Resources, Inc.
2015 Guidance
As of November 4, 2015[1]

2015

Production growth (YOY)	**24% to 26%**
Capital expenditures (non-acquisition, in $ billions)	$2.7
<u>**Operating Expenses:**</u>	
Production expense per Boe	**$4.00 to $4.50**
Production tax (% of oil & gas revenue)	**7.5% to 8.0%**
G&A expense per Boe	**$1.70 to $2.00**
Non-cash equity compensation per Boe	**$0.65 to $0.75**
DD&A per Boe	$20.00 to $22.50
<u>**Average Price Differentials:**</u>	
NYMEX WTI crude oil (per barrel of oil)	**($7.00) to ($9.00)**
Henry Hub natural gas (per Mcf)	$0.00 to ($0.50)
Income tax rate	38%
Deferred taxes	90% to 95%

(1) Bold items above in guidance denote a change from the previous disclosure provided on August 5, 2015

SOURCE Continental Resources

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http://investors.clr.com/2015-11-04-Continental-Resources-Reports-Third-Quarter-2015-Results