Continental Resources Reports Second Quarter 2015 Results

2015 Production Growth Guidance Increased with Capital Expenditures Trending Toward $150 Million Below 2015 Budget
Company Reduces Cash Operating Cost Guidance by $1.00 per Barrel of Oil Equivalent Produced
Company's First STACK Well Flows 2,076 Barrels of Oil Equivalent per Day (76% Crude Oil)
Second Successful SCOOP Woodford Density Pilot Flows at Combined Peak Rates of 93.3 Million Cubic Feet of Natural Gas and 9,058 Barrels of Oil per Day from 9 New Wells
Production Averaged 226,547 Barrels of Oil Equivalent per Day

OKLAHOMA CITY, Aug. 5, 2015 /PRNewswire/ -- Continental Resources, Inc. (NYSE: CLR) (Continental or the Company) today announced second quarter 2015 operating and financial results.

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Continental reported net income of $0.4 million, or $0.00 per diluted share, for the second quarter of 2015. Adjusted net income for the second quarter of 2015 was $48.5 million, or $0.13 per diluted share.

EBITDAX for the second quarter of 2015 was $647 million, compared with EBITDAX of $868 million for the second quarter of 2014, reflecting the decline in average commodity prices since June 2014, partially offset by increased production. 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.

"Continental had a very productive quarter with strong production growth that reflects our best-in-class inventory," said Harold Hamm, Chairman and Chief Executive Officer. "Our teams are performing very efficiently, and consequently we are revising 2015 guidance to reflect increased production and lower operating costs. While we're not formally changing guidance on capital expenditures, we are currently trending approximately $150 million under budget for the year.

"We are reporting outstanding results for our first STACK well in Oklahoma, the Ludwig 1-22-15XH in Blaine County," Mr. Hamm said. "Early production has been strong, flowing 76% oil with a rich natural gas stream, validating our view of STACK as another large, long-term growth driver for Continental."

2015 Guidance Update

Based on strong operating results in first half 2015, the Company is increasing its production growth guidance to a range of 19% to 23% for 2015, compared with earlier guidance of 16% to 20% growth over the previous year.

Concurrently, Continental has issued lower 2015 expense guidance for production cost, general and administrative cost and non-cash equity compensation per barrel of oil equivalent (Boe) of production, reflecting increased operating efficiencies companywide. In total, the guidance on cash costs for 2015 has been reduced by $1.00 per Boe of production. Production expense is now expected to be in a range of $4.75 to $5.25 per Boe for the year, and G&A expense is expected to be in a range of $1.75 to $2.25 per Boe. Non-cash equity compensation is expected to be $0.70 to $0.80 per Boe for the year.

	Previous 2015 Guidance	Updated 2015 Guidance
Production growth	16% to 20%	19% to 23%

Production expense per Boe	$5.50 to $6.00	$4.75 to $5.25
G&A expense per Boe	$2.00 to $2.50	$1.75 to $2.25
Non-cash equity compensation per Boe	$0.75 to $0.95	$0.70 to $0.80

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

Continental is currently operating 25 rigs, including 10 rigs in the Bakken and 15 rigs in Oklahoma. While the Company believes current low oil prices are unsustainable long-term, it intends to reduce its Bakken operated rig count by 20% by year-end 2015, if low commodity prices persist.

Cost Reductions

Continental's drilling and completion costs for most operated wells have declined approximately 20% since year-end 2014, due primarily to lower service costs. Cost reductions are in line with expectations announced on the first quarter earnings call. The Company's estimated average drilling and completion cost for operated wells in the Bakken is currently $7.7 million per well, compared with $9.6 million per well at year-end 2014. The current estimated average drilling and completion cost for operated Woodford wells in the South Central Oklahoma Oil Province (SCOOP) has decreased to $9.8 million, compared with $12.2 million per well at year-end 2014, based on a 7,500-foot lateral.

The Company expects to realize 5% to 10% additional reductions by year-end 2015 from a combination of additional service cost cuts and efficiency gains. As an example of efficiency gains, Continental recently set a new Company record by drilling the 9,500-foot lateral portion of a Bakken well in 2.73 days, nearly four days faster than the Company's 2014 average. In the first half of 2015, Continental drilled 12 wells from spud to total depth in 14 days, which was three days faster than the Company's 2014 average, saving the Company approximately $0.2 million per well.

Production

Second quarter 2015 net production totaled 20.6 million Boe, or 226,547 Boe per day, a sequential increase of 10% from first quarter 2015 and 35% higher than second quarter 2014. Total net production for the second quarter included 149,897 barrels of oil (Bo) per day (66% of production) and 459.9 million cubic feet (MMcf) of natural gas per day (34% of production). In second quarter 2015, sales volumes totaled 20.9 million Boe, marginally higher than production for the quarter.

Second half 2015 daily production is expected to level off and then decline slightly, reflecting the approximate 50% reduction in operated rigs since late 2014. Continental expects to exit 2015 with production in the range of 210,000 to 215,000 Boe per day.

The following table provides the Company's year-to-date average daily production by region.

Boe per day	2Q 2015	1Q 2015	2Q 2014	YTD 2015	YTD 2014
North Region:					
North Dakota Bakken	127,872	120,957	94,702	124,434	89,244
Montana Bakken	13,116	14,581	13,871	13,844	13,802
Red River Units	12,669	12,953	14,125	12,810	14,132
Other	1,835	681	961	1,261	893
South Region:					
SCOOP	62,546	49,882	34,265	56,249	31,827
NW Cana (1)	4,410	3,433	5,223	3,924	5,452
Arkoma	2,112	2,124	2,599	2,118	2,582
Other	1,987	2,218	2,207	2,102	2,323
Total	226,547	206,829	167,953	216,742	160,255

(1) NW Cana volumes for 2015 have decreased from 2014 levels due in part to the Company's September 30, 2014 sale of 49.9% of its interest in certain wells under the Company's joint development agreement with SK E&S.

STACK

Continental recently completed its first well in the STACK play of Oklahoma targeting the Meramec reservoir, the Ludwig 1-22-15XH well in Blaine County. The Ludwig tested at an initial production rate of 1,580 Bo and 3.0 MMcf of natural gas per day, which equals an equivalent production rate of 2,076 Boe per day from a 9,711-foot lateral. While only in its first week of production, the well is flowing up casing with strong pressure, 2,100 psi on a 34/64" choke. Production thus far has been 44° API gravity oil and 1,460 Btu natural gas.

"The Ludwig's performance is exceptional," said Glen Brown, Senior Vice President for Exploration. "The Ludwig and other completions in the area demonstrate that high production rates are repeatable and identify STACK as a new resource play for Continental."

The Company recently finished drilling its second STACK well, the Marks 1-9-4XH, and has begun to drill a third, the Ladd 1-5-8XH. Continental plans to move a second operated rig from SCOOP into the STACK play later this quarter and expects to spud another five to six STACK wells by year end.

Continental has 136,400 net acres in the play, primarily in Blaine and Dewey counties, with approximately 60% of the leasehold held by production.

SCOOP Woodford and Springer

Continental's activities in the SCOOP are primarily focused on the Woodford formation and Springer formation, which is located approximately 1,000 to 1,500 feet above the Woodford.

In second quarter 2015, total SCOOP net production averaged 62,546 Boe per day, an increase of 25% sequentially over first quarter 2015 and 83% over second quarter 2014. SCOOP production represented 28% of the Company's total production in second quarter 2015.

During second quarter 2015, the Company completed 18 net (55 gross) operated and non-operated wells while operating an average of 12 operated rigs and three completion crews in SCOOP.

SCOOP Woodford: Honeycutt Density Test Delivers Outstanding Results

In second quarter 2015, SCOOP Woodford net production averaged 53,353 Boe per day, an increase of 29% sequentially over first quarter 2015. In second quarter 2015, the Company completed 15 net (50 gross) operated and non-operated Woodford wells in the play.

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

- The Dungan 1-31-30XH well in Grady County tested at 1,754 Boe per day (50% oil), from 6,031 feet of completed lateral; and
- The Kellner 1-19H well in Garvin County tested at 16.9 MMcf equivalent (MMcfe) per day, which included 751 Bo per day (2,816 Boe per day), from 4,971 feet of completed lateral.

Continental's second quarter results included another successful 10-well density pilot project, the Honeycutt unit in northeastern Stephens County. The nine new wells in the density test flowed at combined peak production rates of 93.3 MMcf and 9,058 Bo per day, or 24,603 Boe per day. The Honeycutt wells produced at an average rate comparable to the prior nearby Poteet density test, and the oil percentage of production in the Honeycutt unit was 37% of total production compared with 12% in the Poteet unit. The Company has an average working interest of 50% in the Honeycutt unit.

The Honeycutt project was the Company's second dual-level density pilot in the SCOOP Woodford condensate window, consisting of five wells each in the upper and lower halves of the Woodford, spaced approximately 1,025 feet apart with 125 feet of vertical separation. Average lateral length for the new wells was 7,369 feet.

"The Honeycutt results are further confirmation of the tremendous resource potential of the SCOOP Woodford," said Jack Stark, President and Chief Operating Officer.

SCOOP Springer Continues to Impress

In second quarter 2015, SCOOP Springer net production averaged 9,193 Boe per day, an increase of 10% sequentially over first quarter 2015. The Company completed 3 net (5 gross) operated and non-operated Springer wells in second quarter 2015.

Select test rates from recent SCOOP Springer operated wells include:

- The Chester 1-32H well in Grady County tested at 1,733 Boe per day (70% oil) from 4,999 feet of completed lateral; and
- The Celesta 1-5-32XH well in Stephens County tested at 1,199 Boe per day (79% oil) from 7,119 feet of completed lateral. This is the second extended lateral completed by Continental in the Springer.

Northwest Cana Joint Development Agreement

In second quarter 2015, Northwest Cana net production averaged 4,410 Boe per day. The Company completed 2.3 net (5 gross) operated and non-operated NW Cana wells in second quarter 2015.

Select test rates from recent NW Cana operated wells include:

- The Heckenberg 1-19-30XH well in Blaine County tested at 15.5 MMcfe per day (2,583 Boe per day) from 7,865 feet of completed lateral;
- The Jones Bay 1-7-6XH well in Blaine County tested at 12.5 MMcfe per day (2,092 Boe per day), from 8,373 feet of completed lateral; and
- The Akin 1-27-22XH well in Custer County tested at 9.9 MMcfe per day, which included 42 Bo per day (1,649 Boe per day), from 8,390 feet of completed lateral.

Bakken

Continental's Bakken production averaged 140,988 Boe per day in the second quarter of 2015, an increase of 4% compared with first quarter 2015 and an increase of 30% compared with second quarter 2014. The Company completed 56 net (159 gross) operated and non-operated Middle Bakken and Three Forks wells during second quarter 2015. In the most recent quarter, the Company operated an average of 10 rigs and three completion crews in the Bakken.

Continental's 2015 Bakken drilling program is focused on core leasehold in Williams, McKenzie, Mountrail and Dunn counties, targeting an average estimated ultimate recovery (EUR) of approximately 800,000 Boe per well. Overall, this concentration in the core of the play, combined with a 20% reduction in completed well cost, is expected to increase capital efficiency in terms of reserves per capital dollar invested by approximately 80% and to reduce finding and development costs per Boe by approximately 45% compared to full-year 2014.

Most wells are being completed using a 30-stage enhanced completion with either slickwater or hybrid completion designs, depending on the specific formation and reservoir domain. Wells in Williams and McKenzie counties completed with these designs continue to deliver an average 90-day production increase of approximately 40% for hybrid completions and 50% for slickwater completions, compared with offset legacy wells with previous cross-linked gel completion designs. EUR uplifts have been in a range of 25% to 45%.

The Company estimates it has at least 10 years of drilling inventory, with wells averaging 775,000 Boe per well in EUR, in the core of the Bakken. This assumes an average of 15 operated drilling rigs per year and no additional improvements in drilling or completion technologies.

The Company currently has 95 gross operated Bakken wells drilled and waiting on first production, compared to 115 at the end of first quarter 2015. The Company currently expects to increase this total to approximately 100 gross operated Bakken wells drilled and waiting on first production at year-end 2015.

Financial Update

In second quarter 2015, Continental's average realized sales price excluding the effects of derivative positions was $49.84 per Bo and $2.31 per Mcf, or $37.82 per Boe. Settlements of matured commodity derivative positions generated a $0.31 gain per Mcf of natural gas, resulting in a net gain on matured derivatives of $13.2 million, or $0.63 per Boe, for the second quarter of 2015. Based on realizations without the effect of derivatives, the Company's second quarter 2015 oil differential was $8.18 per barrel below the NYMEX daily average for the period. The realized natural gas price differential for second quarter 2015 was a negative $0.33 per Mcf.

For the second quarter of 2015, production expense was $4.39 per Boe of sales, compared with $5.05 per Boe for first quarter 2015. Other select operating costs and expenses for second quarter 2015 included production taxes of 7.8% on oil and natural gas sales; depreciation, depletion, amortization and accretion (DD&A) expense of $21.68 per Boe; cash general and administrative (G&A) expense of $1.34 per Boe; and equity compensation expense of $0.77 per Boe.

Non-acquisition capital expenditures for second quarter 2015 totaled approximately $585.5 million, which was $26.9 million, or 4%, below budget for the quarter. Total capital expenditures for the quarter included $518.3 million in exploration and development drilling, $22.1 million in leasehold and seismic, and $45.1 million in workovers, recompletions and other. In addition, acquisition capital expenditures totaled approximately $6.4 million for second quarter 2015.

As of June 30, 2015, Continental's balance sheet included approximately $25.5 million in cash and cash equivalents, and $6.99 billion in long-term debt, including $1.23 billion of borrowings against the Company's credit facility.

"We are very pleased with the updated 2015 guidance and our team's ability to align cash flow in this challenging market," said John Hart, Chief Financial Officer. "Second half 2015 capital expenditures are projected to decline sequentially quarter over quarter, reflecting the slowdown in spending relative to the first half of the year's capital spending rate."

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 June 30, 2015	2014	Six months ended June 30, 2015	2014
Average daily production:				
Crude oil (Bbl per day)	149,897	116,441	146,722	111,447
Natural gas (Mcf per day)	459,898	309,074	420,123	292,847
Crude oil equivalents (Boe per day)	226,547	167,953	216,742	160,255
Average sales prices, excluding effect from derivatives:				
Crude oil ($/Bbl)	$49.84	$92.31	$44.46	$91.12
Natural gas ($/Mcf)	$2.31	$5.43	$2.48	$6.20
Crude oil equivalents ($/Boe)	$37.82	$74.09	$34.93	$74.53
Production expenses ($/Boe)	$4.39	$5.50	$4.70	$5.62
Production taxes (% of oil and gas revenues)	7.8%	8.3%	8.0%	8.0%
DD&A ($/Boe)	$21.68	$21.28	$21.36	$20.88
General and administrative expenses ($/Boe)	$1.34	$2.08	$1.58	$2.24
Non-cash equity compensation ($/Boe)	$0.77	$0.98	$0.70	$0.91
Net income (loss) (in thousands)	$403	$103,538	($131,568)	$329,772
Diluted net income (loss) per share(1)	$0.00	$0.28	($0.36)	$0.89
Adjusted net income (in thousands) (2)	$48,450	$277,143	$14,631	$549,439
Adjusted diluted net income per share (1) (2)	$0.13	$0.75	$0.04	$1.48
EBITDAX (in thousands) (2)	$647,009	$867,938	$1,086,435	$1,643,345

(1) Net income per share amounts for the 2014 periods have been retroactively adjusted to reflect the Company's 2-for-1 stock split in September 2014.

(2) Adjusted net income, adjusted diluted net income 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, adjusted diluted net income per share, and EBITDAX to the most directly comparable U.S. GAAP financial measures are provided subsequently under the header *Non-GAAP Financial Measures*.

Second Quarter Conference Call

Continental plans to host a conference call to discuss second quarter results on Thursday, August 6, 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, August 6, 2015
Dial-in:	855-291-6799
Intl. dial-in:	315-625-3058
Conference ID:	64154845

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

Replay number:	855-859-2056
Intl. replay	404-537-3406
Conference ID:	64154845

Continental plans to publish a second quarter 2015 summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on August 6, 2015.

Upcoming Conferences

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

August 18, 2015	Enercom's The Oil & Gas Conference: Denver
August 26, 2015	Heikkinen Energy Conference: Houston
September 9, 2015	Barclays 2015 CEO Energy-Power Conference: NYC

Instructions regarding how to access the live and replay webcast for the Enercom and Barclays presentations 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, returns, budgets, costs, business strategy, objectives, and cash flow, 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.

Investor Contact:	**Media Contact:**
J. Warren Henry	Kristin Thomas
Vice President, Investor Relations & Research	Vice President, Public Relations
405-234-9127	405-234-9480
Warren.Henry@CLR.com	Kristin.Thomas@CLR.com
Alyson L. Gilbert	
Senior Analyst, Investor Relations	
405-774-5814	
Alyson.Gilbert@CLR.com	

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

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Revenues:	*In thousands, except per share data*			
Crude oil and natural gas sales	$ 790,102	$ 1,138,085	$ 1,372,694	$ 2,140,418
Gain (loss) on derivative instruments, net	(4,737)	(262,524)	28,018	(302,198)
Crude oil and natural gas service operations	11,009	10,534	21,306	20,370
Total revenues	796,374	886,095	1,422,018	1,858,590
Operating costs and expenses:				
Production expenses	91,735	84,521	184,675	161,407
Production taxes and other expenses	61,545	97,025	109,908	175,327
Exploration expenses	109	11,205	14,449	16,018
Crude oil and natural gas service operations	7,092	5,979	10,986	14,053

Crude oil and natural gas service operations	7,092	5,979	10,986	14,053
Depreciation, depletion, amortization and accretion	452,957	326,871	839,469	599,732
Property impairments	76,872	79,316	224,432	137,524
General and administrative expenses	44,190	46,919	89,571	90,455
(Gain) loss on sale of assets, net	(20,573)	(2,135)	(22,643)	6,363
Total operating costs and expenses	713,927	649,701	1,450,847	1,200,879
Income (loss) from operations	82,447	236,394	(28,829)	657,711
Other income (expense):				
Interest expense	(78,442)	(72,841)	(153,505)	(135,816)
Other	540	793	886	1,552
	(77,902)	(72,048)	(152,619)	(134,264)
Income (loss) before income taxes	4,545	164,346	(181,448)	523,447
Provision (benefit) for income taxes	4,142	60,808	(49,880)	193,675
Net income (loss)	$ 403	$ 103,538	$ (131,568)	$ 329,772
Basic net income (loss) per share[1]	$ -	$ 0.28	$ (0.36)	$ 0.89
Diluted net income (loss) per share[1]	$ -	$ 0.28	$ (0.36)	$ 0.89

(1)	Net income per share amounts for the 2014 periods have been retroactively adjusted to reflect the Company's 2-for-1 stock split in September 2014.

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

	June 30, 2015	December 31, 2014
Assets	*In thousands*	
Current assets	$1,200,313	$ 1,389,601
Net property and equipment [1]	14,169,202	13,635,852
Other noncurrent assets[2]	40,336	50,580
Total assets	$15,409,851	$ 15,076,033
Liabilities and shareholders' equity		
Current liabilities	$1,315,569	$ 1,952,013
Long-term debt, net of current portion [2]	6,988,046	5,926,800
Other noncurrent liabilities	2,250,209	2,229,376
Total shareholders' equity	4,856,027	4,967,844
Total liabilities and shareholders' equity	$15,409,851	$ 15,076,033

(1)	Balance is net of accumulated depreciation, depletion and amortization of $5.56 billion and $4.68 billion as of June 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 June 30,		Six months ended June 30,	
In thousands	2015	2014	2015	2014
Net income (loss)	$403	$103,538	$(131,568)	$329,772
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash expenses	544,438	682,359	1,039,534	1,180,698
Changes in assets and liabilities	(150,219)	(44,106)	8,846	(78,017)
Net cash provided by operating activities	394,622	741,791	916,812	1,432,453
Net cash used in investing activities	(684,899)	(1,057,807)	(1,963,303)	(2,077,287)
Net cash provided by financing activities	267,283	1,041,444	1,051,666	1,393,315
Effect of exchange rate changes on cash	807	-	(4,098)	-
Net change in cash and cash equivalents	(22,187)	725,428	1,077	748,481
Cash and cash equivalents at beginning of period	47,645	51,535	24,381	28,482
Cash and cash equivalents at end of period	$25,458	$776,963	$25,458	$776,963

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 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 June 30,		Six months ended June 30,	
In thousands	2015	2014	2015	2014
Net income (loss)	$ 403	$ 103,538	$ (131,568)	$ 329,772
Interest expense	78,442	72,841	153,505	135,816
Provision (benefit) for income taxes	4,142	60,808	(49,880)	193,675
Depreciation, depletion, amortization and accretion	452,957	326,871	839,469	599,732
Property impairments	76,872	79,316	224,432	137,524
Exploration expenses	109	11,205	14,449	16,018
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	4,737	262,524	(28,018)	302,198
Total cash (paid) received on derivatives, net	13,182	(64,143)	36,617	(97,407)
Non-cash (gain) loss on derivatives, net	17,919	198,381	8,599	204,791
Non-cash equity compensation	16,165	14,978	27,429	26,017
EBITDAX	$ 647,009	$ 867,938	$ 1,086,435	$ 1,643,345

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	2015	2014	2015	2014
Net cash provided by operating activities	$ 394,622	$ 741,791	$ 916,812	$ 1,432,453
Current income tax provision	5	1,552	10	3,104
Interest expense	78,442	72,841	153,505	135,816
Exploration expenses, excluding dry hole costs	109	6,822	6,446	11,635
Gain (loss) on sale of assets, net	20,573	2,135	22,643	(6,363)
Other, net	3,039	(1,309)	(4,135)	(11,317)
Changes in assets and liabilities	150,219	44,106	(8,846)	78,017
EBITDAX	$ 647,009	$ 867,938	$ 1,086,435	$ 1,643,345

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. Net income per share amounts for the 2014 periods have been retroactively adjusted to reflect the Company's 2-for-1 stock split in September 2014.

	Three months ended June 30,			
	2015		2014	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (GAAP)	$ 403	$ 0.00	$ 103,538	$ 0.28
Adjustments, net of tax:				
Non-cash loss on derivatives, net	11,110	0.03	124,981	0.34
Property impairments	49,693	0.13	49,969	0.13
Gain on sale of assets, net	(12,756)	(0.03)	(1,345)	-
Adjusted net income (Non-GAAP)	$ 48,450	$ 0.13	$ 277,143	$ 0.75
Weighted average diluted shares outstanding	370,873		370,334	
Adjusted diluted net income per share (Non-GAAP)	$ 0.13		$ 0.75	

	Six months ended June 30,			
	2015		2014	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (loss) (GAAP)	$ (131,568)	$ (0.36)	$ 329,772	$ 0.89
Adjustments, net of tax:				
Non-cash loss on derivatives, net	5,331	0.01	129,018	0.35
Property impairments	154,908	0.42	86,640	0.23
(Gain) loss on sale of assets, net	(14,040)	(0.03)	4,009	0.01
Adjusted net income (Non-GAAP)	$ 14,631	$ 0.04	$ 549,439	$ 1.48
Weighted average diluted shares outstanding	370,920		370,388	
Adjusted diluted net income per share (Non-GAAP)	$ 0.04		$ 1.48	

Continental Resources, Inc.
2015 Guidance
As of August 5, 2015[(1)]

	2015
Production growth (YOY)	**19% to 23%**
Capital expenditures (non-acquisition, in $ billions)	$2.70
<u>**Operating Expenses:**</u>	
Production expense per Boe	**$4.75 to $5.25**
Production tax (% of oil & gas revenue)	7.5% to 8.5%
G&A expense per Boe	**$1.75 to $2.25**
Non-cash equity compensation per Boe	**$0.70 to $0.80**
DD&A per Boe	$20.00 to $22.50

Average Price Differentials:	
NYMEX WTI crude oil (per barrel of oil)	($7.00) to ($10.00)
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 May 6, 2015

SOURCE Continental Resources

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http://investors.clr.com/2015-08-05-Continental-Resources-Reports-Second-Quarter-2015-Results,1