CLR Investors

Continental Resources Reports First Quarter 2014 Results

First Quarter 2014 Adjusted Net Income Totals $272 Million, or $1.47 per Diluted Share; First Quarter 2014 EBITDAX of $775 Million
14-Well Hawkinson Density Test Production Performance Remains Strong After 150 Days on Production
Strong Early Performance at Rollefstad Density Pilot, Eight New Wells Have Combined Initial Production of 22,460 Boe per Day

OKLAHOMA CITY, May 7, 2014 /PRNewswire/ -- Continental Resources, Inc. (NYSE: CLR) ("Continental" or the "Company") today announced first quarter 2014 operating and financial results. Net income for the quarter ended March 31, 2014 was $226 million, or $1.22 per diluted share, compared with net income of $133 million, or $0.72 per diluted share, for fourth quarter 2013. Excluding items typically excluded from published analyst estimates, adjusted net income for first quarter 2014 was $272 million, or $1.47 per diluted share, a 19% increase over adjusted net income of $228 million, or $1.23 per diluted share, for fourth quarter 2013.

Logo - http://photos.prnewswire.com/prnh/20120327/DA76602LOGO

EBITDAX for first quarter 2014 was $775 million, a 9% increase over EBITDAX of $712 million for fourth quarter 2013 and 25% above EBITDAX for first quarter 2013. Definitions and reconciliations of adjusted net income, 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.

Harold G. Hamm, Chairman and Chief Executive Officer, commented, "2014 is off to a solid start. We battled challenging weather in the quarter, and several pad locations experienced delays getting connected. However, we are very proud of the efforts of the team to stay focused on execution in order to achieve our target of 26% to 32% organic production growth in 2014."

Production and Sales Volumes

First quarter 2014 net production totaled 13.7 million barrels of oil equivalent ("Boe"), or 152,500 Boe per day, a sequential increase of 6% from fourth quarter 2013 and 25% higher than first quarter 2013. Total net production included approximately 106,400 barrels of oil per day (70% of production) and approximately 276 million cubic feet of natural gas ("MMcf") per day (30% of production). In first quarter 2014, sales volumes totaled approximately 13.4 million Boe, or 148,400 Boe per day, which was approximately 363,000 barrels below the amount produced for the quarter. This increased level of oil inventory is attributed to recent line fill requirements, logistical management of volumes during winter and initial tank fill at oil storage facilities. As part of the Company's 2013-2014 facilities capital projects, the Company is in the process of adding incremental oil storage facilities with a maximum working capacity of 240,000 barrels, providing greater flexibility and improved balancing of crude oil sales logistics. Continental anticipates additional significant line fill during the summer months of 2014 as new pipelines are put into service.

Hamm added, "Within the next few quarters new pipelines will be commissioned along with our new tank storage in the Bakken which will serve us well by reducing transportation costs, improving differentials and adding significant optionality to our portfolio marketing strategy. These new assets and our proactive steps are the natural next phase in the evolution of our Company's marketing and infrastructure in the Bakken as we move closer to full-field development."

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

Boe per day	1Q 2014	4Q 2013	1Q 2013
North Region:			
North Dakota Bakken	83,725	80,374	67,575
Montana Bakken	13,732	12,961	9,352
Red River Units	14,140	14,398	15,055
Other	824	812	1,267
South Region:			
SCOOP	29,363	23,754	14,243
NW Cana	5,685	6,696	8,323
Arkoma	2,565	2,769	3,234
Other	2,437	2,490	2,483
Total	152,471	144,254	121,532

Bakken Development

Continental's Bakken production totaled 97,457 Boe per day in first quarter 2014, an increase of 4% compared to fourth quarter 2013 and an increase of 27% compared to first quarter 2013. The Company completed 67 net (177 gross) wells in the Bakken during first quarter 2014. North Dakota completions included 50 net wells in Middle Bakken ("MB") and Three Forks One ("TF1") and six net wells in each of the Three Forks Two ("TF2") and Three Forks Three ("TF3"). Montana completions for first quarter 2014 totaled 11 net wells, all in the MB.

The Company concluded first quarter 2014 with an inventory of approximately 100 gross Bakken wells drilled, but not yet completed. As surface conditions have improved, the Company has been able to accelerate completions, with approximately half of the completions in first quarter 2014 occurring in March. The Company currently expects to complete approximately 287 net (870 gross) wells in the Bakken in full-year 2014, including both operated and non-operated wells, which is subject to change. The Company operated 20 rigs in the play in first quarter 2014 and anticipates operating an average rig count of 21 throughout 2014.

Enhanced Bakken Completions

During fourth quarter 2013 and first quarter 2014, Continental operated and completed approximately 40 gross wells using various completion methods, including several different test elements such as fluid type, increased proppant and shorter stage length, among other items. Early results from several of the techniques are encouraging, which include two slickwater completion tests indicating an approximate 30% increase in the initial 120 days of production above the Company's blended 603,000 Boe model estimated ultimate recovery ("EUR") and approximately 50% above existing offset wells in the area. Estimated incremental completed well costs for these enhanced completions is an additional \$1.5 - \$2.0 million above the Company's standard completed well cost of \$7.8 - \$8.0 million today and \$7.5 million targeted by year-end 2014. Continental plans to continue enhanced completions on approximately 20% (60 gross wells) of its Bakken activity in 2014 to determine the optimal completion design to maximize value. It is important to evaluate more production history as well as build a statistical database of results before firm conclusions can be drawn.

Bakken Density Pilot Project Update

In 2013, the Company embarked on a plan to test different areas across the Bakken field to determine what well density and pattern best maximizes crude oil recovery and returns. In all, the Company has initiated seven density pilot projects, and all are designed to develop the MB, TF1, TF2 and TF3 across a broad section of Continental's 1.2 million net acres of leasehold. Three of these projects are testing 1,320 foot inter-well spacing and four are testing 660 foot inter-well spacing. The Hawkinson 1,320 foot inter-well spacing pilot project was the first to be completed by the Company and was announced as a fourth quarter 2013 completion. During first quarter 2014 the Company completed two additional 1,320 foot inter-well spacing pilot projects, the Rollefstad and Tangsrud units. The four remaining pilot projects are testing 660 foot inter-well spacing and are in various stages of drilling or completion. These include the Wahpeton, Mack, Lawrence and Hartman units. The Wahpeton unit, located in McKenzie County, includes 13 wells and is expected to be completed by mid summer. The Lawrence, Mack and Hartman units include a combined 18 new wells and six existing producers, and are expected to be completed in the second half of 2014.

The Hawkinson Unit

Continental successfully completed the first density pilot project in North Dakota at the Hawkinson unit in Dunn County in October 2013. The 14 individual wells within the unit tested at a combined rate of 14,850 Boe per day, which included three existing producing wells. The project included four MB, three TF1, four TF2 and three TF3 wells spaced 1,320 feet apart in the same zone and offset 660 feet in the adjacent zones.

Performance of the wells during their initial 150 producing days continues to be very strong with 13 of the 14 wells producing on average 50% above the Company's 603,000 Boe EUR model. The remaining well is a TF3 producer that is producing on trend 35% below the 603,000 Boe EUR model. Although it is still early in the life of the wells in this unit, to date the original existing three wells continue to produce on average at or better than prior to the commencement of drilling and completing the additional 11 wells in the density test. Continental has an approximate 55% working interest in the Hawkinson unit.

The Tangsrud Unit

The Tangsrud density pilot project located in Divide County, ND was designed to both test and extend the productive footprint of the Lower Three Forks formation to the north in the Bakken and test 1,320 foot inter-well spacing across the MB, TF1, TF2 and TF3. The project includes two existing wells and 12 new wells spaced 1,320 feet apart. The 12 new wells were completed in first quarter 2014 and had a combined maximum 24-hour initial rate of 5,340 Boe per day, or 445 Boe per day per well. The five newly completed wells in the unit in the MB and TF1 had an average initial rate of 670 Boe per day and the seven newly completed TF2 and TF3 initially produced at approximately 285 Boe per day. All the wells in the unit were completed using Continental's standard completion method (30 stages, 100,000 lbs. of proppant per stage) and have recently been put on pump, producing 87% oil. The wells are being monitored closely to assess if economics using current completion designs will justify including TF2 and TF3 in future development in this particular area. Continental has an approximate 96% working interest in the Tangsrud unit.

The Rollefstad Unit

The Rollefstad density pilot project located in McKenzie County, ND was completed in April 2014 and is located in the Antelope project area. This pilot includes eight new wells (two in each of the MB, TF1, TF2 and TF3) and 3 legacy wells (two MB and one TF1) spaced 1,320 feet apart. The eight new wells had a combined maximum 24-hour initial rate of 22,460 Boe per day or 2,810 Boe per day per well. Seven new completions at the Rollefstad unit were conducted using twice the proppant, 200,000 lbs. per stage, compared to the Company's standard design and had an average initial rate of 2,675 Boe per well. One well was completed at three times the proppant, 300,000 lbs. per stage, compared to the Company's standard completion design and had an initial rate of 3,720 Boe per day. Due to the larger enhanced completion techniques used and the temporary limitation of the existing infrastructure at the unit, a larger test vessel was used to help measure these significant initial rates. Seven of the eight new wells continue to flow naturally, thus it is too early in the life of the wells to estimate ultimate recovery. Continental has an 80% working interest in the unit.

W. F. "Rick" Bott, Continental's President and Chief Operating Officer, commented, "The continued success of our Hawkinson downspacing pilot gives us confidence we can take our full-field development plans across a large portion of the play. The Rollefstad results are very exciting as the enhanced completions have the opportunity to dramatically change the overall return profile of the play. It is still very early in the process and different areas and formations may respond differently. Our goal is to combine our completion design tests with our downspacing pilot results to maximize recoveries, accelerate production earlier in the life of the well and thus drive higher realized returns and greater net present value."

Growth in SCOOP Continues

Continental continues to deliver excellent results from its drilling activity in the South Central Oklahoma Oil Province ("SCOOP"). The play, discovered by Continental and announced in October 2012, currently extends approximately 120 miles across several counties in Oklahoma and contains oil and condensate-rich fairways as delineated by approximately 450 gross industry wells. Continental currently operates or has a working interest in approximately 185 wells across its approximately 425,000 net acres of leasehold in the play.

In first quarter 2014, SCOOP net production averaged 29,363 Boe per day, an increase of 24% sequentially and 106% above first quarter 2013. The recent growth was driven by the addition of 11 net (13 gross) operated and 2 net (15 gross) non-operated wells in the play during first quarter 2014.

In SCOOP, Continental's primary focus continues to be exploration and appraisal as well as drilling to hold acreage by production ("HBP"), with an increasing shift to 1.5 to 2-mile extended lateral wells for superior returns. The Company operated an average of 19 rigs during first quarter 2014 and plans to average at least 18 operated rigs in the play in 2014, with approximately 50% of the activity consisting of extended lateral wells. Operated well costs in the play are targeted by year-end 2014 to be approximately $8.7 million for a standard 1-mile lateral across the play and approximately $13.5 million for a 2-mile lateral. Continental plans to conduct spacing tests and at least one density pilot in SCOOP in 2014.

In first quarter 2014, average initial one-day test rates from operated wells within the condensate and oil window of SCOOP included:

- The Claudine 1-29-32XH well in Stephens County tested at 18.1 million cubic feet of natural gas equivalent ("MMcfe") per day, which included 245 barrels of oil. The gas stream is estimated at 1,230 British thermal units per standard cubic foot ("Btu/scf"). Continental has a 60% working interest in the well;
- The Chalfant 1-7H well in Stephens County tested at 16.2 MMcfe per day, which included 375 barrels of oil. The gas stream is estimated at 1,190 Btu/scf. Continental has a 28% working interest in the well; and
- The Green Acres 1-36H well in Garvin County tested at 980 Boe per day, which included 78% oil. Continental has a 97% working interest in the well.

Financial Update and Guidance

Continental's average realized sales price excluding the effects of derivative positions was $89.73 per barrel of oil and $7.06 per thousand cubic feet of natural gas ("Mcf"), or $75.03 per Boe for first quarter 2014. Settlements of matured commodity derivative positions generated a $2.51 loss per barrel of oil and $0.41 loss per Mcf of natural gas, resulting in a net loss on matured derivatives of $33.3 million, or $2.49 per Boe for the first quarter 2014. Based on realizations without the effect of derivatives, the Company's first quarter 2014 oil differential was $8.98 per barrel below the NYMEX daily average for the period. The realized natural gas price differential for first quarter 2014 was a positive $2.14 per Mcf.

Production expense per Boe was $5.76 for first quarter 2014. Other select operating costs and expenses for first quarter 2014 included production taxes of 7.7% of oil and natural gas sales; DD&A of $20.43 per Boe; and G&A (cash and non-cash) of $3.26 per Boe.

As of March 31, 2014, Continental's balance sheet included approximately $52 million in cash and cash equivalents and $630 million of borrowings against the Company's $1.5 billion credit facility.

Non-acquisition capital expenditures for first quarter 2014 totaled approximately $1,037 million, including $902 million in exploration and development drilling, $87 million in leasehold and seismic and $48 million in facilities, workovers, recompletions and other. Acquisition capital expenditures totaled approximately $66 million for first quarter 2014.

Continental's 2014 guidance remains unchanged as originally disclosed on September 10, 2013, which includes organic production growth of 26% to 32% with a capital budget of $4.05 billion. A table with the Company's full 2014 guidance, which includes differentials and select cost elements, can be found at the conclusion of this 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.

	1Q 2014	4Q 2013	1Q 2013
Average daily production:			
Crude oil (Bbl per day)	106,398	100,443	86,071
Natural gas (Mcf per day)	276,439	262,866	212,766
Crude oil equivalents (Boe per day)	152,471	144,254	121,532
Average sales prices, excluding effect from derivatives:			
Crude oil ($/Bbl)	$89.73	$84.47	$89.99
Natural gas ($/Mcf)	$7.06	$5.11	$4.59
Crude oil equivalents ($/Boe)	$75.03	$68.12	$71.61
Production expenses ($/Boe)	$5.76	$6.03	$5.70
Production taxes (% of oil and gas revenues)	7.7%	8.1%	8.3%
DD&A ($/Boe)	$20.43	$20.40	$19.72
General and administrative expenses ($/Boe)	$2.43	$2.28	$2.26
Non-cash equity compensation ($/Boe)	$0.83	$0.79	$0.85
Net income (in thousands)	$226,234	$132,824	$140,627
Diluted net income per share	$1.22	$0.72	$0.76
Adjusted net income (in thousands) (1)	$272,297	$228,132	$215,386
Adjusted diluted net income per share (1)	$1.47	$1.23	$1.17
EBITDAX (in thousands) (1)	$775,407	$712,300	$621,528

(1) 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, diluted net income 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*.

Conference Call Information and Summary Presentation

Continental Resources plans to host a conference call to discuss first quarter results on Thursday, May 8, 2014 at 11 a.m. ET (10 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:	11 a.m. ET, Thursday, May 8, 2014
Dial in:	800 708 4539
Intl. dial in:	847 619 6396
Pass code:	37065209

A replay of the call will be available for 30 days on the Company's website or by dialing:

Replay number:	888 843 7419
Intl. replay	630 652 3042
Pass code:	37065209

Continental plans to publish a first quarter summary presentation to its website at www.CLR.com prior to the start of its earnings conference call on May 8, 2014.

Upcoming Conferences

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

May 20, 2014	UBS Global Oil & Gas Conference, Austin, TX
June 3, 2014	RBC Capital Markets' Global Energy and Power Conference, New York, NY

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 10 independent oil producer in the United States. Based in Oklahoma City, Continental is the largest leaseholder and producer in the nation's premier oil field, the Bakken play of North Dakota and Montana. The Company also has significant positions in Oklahoma, including its recently discovered SCOOP play and the Northwest Cana play. With a focus on the exploration and production of oil, Continental is on a mission to unlock the technology and resources vital to American energy independence. In 2014, the Company will celebrate 47 years of operation. 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, 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 the expectations reflected in the forward-looking statements are reasonable and based on reasonable assumptions, no assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. When considering forward-looking statements, readers should keep in mind the risk factors and other cautionary statements described under Part I, Item 1A. Risk Factors included in the Company's Annual Report on Form 10-K for the year ended December 31, 2013, registration statements and other reports filed from time to time with the Securities and Exchange Commission ("SEC"), and other announcements the Company makes from time to time.

The Company cautions readers these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control, incident to the exploration for, and development, production, and sale of, crude oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling, completion and production equipment and services and transportation infrastructure, environmental risks, drilling and other operating risks, lack of availability and security of computer-based systems, regulatory changes, the uncertainty inherent in estimating crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, and the other risks described under Part I, Item 1A. Risk Factors in the Company's Annual Report on Form 10-K for the year ended December 31, 2013, 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 hereof. 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. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that the Company, or persons acting on its behalf, may make.

Except as otherwise required by applicable law, the Company disclaims any duty to update any forward-looking statements to reflect events or circumstances after the date of this press release.

CONTACTS: Continental Resources, Inc.

Investor Contact:	Media Contact:
John Kilgallon	Kristin Miskovsky
Vice President, Investor Relations	Vice President, Public Relations
405-234-9330	405-234-9480
John.Kilgallon@CLR.com	Kristin.Miskovsky@CLR.com

Continental Resources, Inc.
Unaudited Condensed Consolidated Statements of Income

	Three months ended March 31,	
	2014	2013
Revenues:	*In thousands, except per share data*	
Crude oil and natural gas sales	$ 1,002,333	$ 775,931
Loss on derivative instruments, net	(39,674)	(84,831)
Crude oil and natural gas service operations	9,836	11,543
Total revenues	972,495	702,643
Operating costs and expenses:		
Production expenses	76,886	61,804
Production taxes and other expenses	78,302	64,842
Exploration expenses	4,813	9,814

Crude oil and natural gas service operations	8,074	8,597
Depreciation, depletion, amortization and accretion	272,861	213,678
Property impairments	58,208	40,081
General and administrative expenses	43,536	33,817
(Gain) loss on sale of assets, net	8,498	(136)
Total operating costs and expenses	551,178	432,497
Income from operations	421,317	270,146
Other income (expense):		
Interest expense	(62,975)	(47,475)
Other	759	546
	(62,216)	(46,929)
Income before income taxes	359,101	223,217
Provision for income taxes	132,867	82,590
Net income	$ 226,234	$ 140,627
Basic net income per share	$ 1.23	$ 0.76
Diluted net income per share	$ 1.22	$ 0.76

Continental Resources, Inc.
Unaudited Condensed Consolidated Balance Sheets

	March 31, 2014	December 31, 2013
Assets	*In thousands*	
Current assets	$1,241,575	$1,147,266
Net property and equipment [1]	11,443,951	10,721,272
Other noncurrent assets	79,375	72,644
Total assets	$12,764,901	$11,941,182
Liabilities and shareholders' equity		
Current liabilities	$1,567,714	$1,473,156
Long-term debt	5,067,814	4,713,821
Other noncurrent liabilities	1,941,612	1,801,087
Total shareholders' equity	4,187,761	3,953,118
Total liabilities and shareholders' equity	$12,764,901	$11,941,182

(1) Balance is net of accumulated depreciation, depletion and amortization of $3.33 billion and $3.12 billion as of March 31, 2014 and December 31, 2013, respectively.

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

	Three months ended March 31,	
In thousands	2014	2013
Net income	$ 226,234	$ 140,627
Adjustments to reconcile net income to net cash provided by operating activities:		
Non-cash expenses	498,339	428,913
Changes in assets and liabilities	(33,911)	(111,429)
Net cash provided by operating activities	690,662	458,111
Net cash used in investing activities	(1,019,480)	(873,153)
Net cash provided by financing activities	351,871	437,859
Net change in cash and cash equivalents	23,053	22,817
Cash and cash equivalents at beginning of period	28,482	35,729
Cash and cash equivalents at end of period	$ 51,535	$ 58,546

Non-GAAP Financial Measures

EBITDAX

EBITDAX represents 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, and non-cash equity compensation expense. 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. 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 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.

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. Our credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 4.0 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and the letters of credit under our credit facility plus our note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. Our credit facility defines EBITDAX consistent with the presentation below. The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

In thousands	1Q 2014	4Q 2013	1Q 2013
Net income	$226,234	$132,824	$140,627
Interest expense	62,975	63,666	47,475
Provision for income taxes	132,867	78,008	82,590
Depreciation, depletion, amortization and accretion	272,861	270,456	213,678
Property impairments	58,208	58,548	40,081
Exploration expenses	4,813	5,809	9,814
Impact from derivative instruments:			
Total (gain) loss on derivatives, net	39,674	102,202	84,831
Total cash paid on derivatives, net	(33,264)	(9,644)	(6,810)
Non-cash loss on derivatives, net	6,410	92,558	78,021
Non-cash equity compensation	11,039	10,431	9,242
EBITDAX	$775,407	$712,300	$621,528

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

In thousands	1Q 2014	4Q 2013	1Q 2013
Net cash provided by operating activities	$690,662	$584,842	$458,111
Current income tax provision (benefit)	1,552	(4,014)	-
Interest expense	62,975	63,666	47,475
Exploration expenses, excluding dry hole costs	4,813	5,639	7,553
Gain (loss) on sale of assets, net	(8,498)	(24)	136
Other, net	(10,008)	2,020	(3,176)
Changes in assets and liabilities	33,911	60,171	111,429
EBITDAX	$775,407	$712,300	$621,528

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 corporate relocation expenses. 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 nonrecurring transactions. 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 table reconciles earnings and diluted earnings per share as determined under U.S. GAAP to adjusted earnings and adjusted diluted earnings per share for the periods presented.

	1Q 2014		4Q 2013		1Q 2013	
In thousands, except per share data	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS	After-Tax $	Diluted EPS
Net income (GAAP)	$ 226,234	$ 1.22	$ 132,824	$ 0.72	$ 140,627	$ 0.76
Adjustments, net of tax:						
Non-cash loss on derivatives, net	4,038	0.02	58,312	0.31	49,153	0.27
Property impairments	36,671	0.20	36,885	0.20	25,251	0.14
(Gain) loss on sale of assets, net	5,354	0.03	15	-	(86)	-
Corporate relocation expenses	-	-	96	-	441	-
Adjusted net income (Non-GAAP)	$ 272,297	$ 1.47	$ 228,132	$ 1.23	$ 215,386	$ 1.17
Weighted average diluted shares outstanding	185,028		185,007		184,656	
Adjusted diluted net income per share (Non-GAAP)	$ 1.47		$ 1.23		$ 1.17	

Continental Resources, Inc.
2014 Guidance Outlook
As of May 7, 2014*

	2014
Production growth (YOY)	26% to 32%
Capital expenditures (non-acquisition)	$4.05B
<u>Operating Expenses:</u>	
Production expense per Boe	$5.60 to $6.10
Production tax (% of oil & gas revenue)	8% to 9%
DD&A per Boe	$17.50 to $19.50
G&A expense per Boe	$2.00 to $2.50
Non-cash equity compensation per Boe	$0.70 to $0.90
<u>Average Price Differentials:</u>	
NYMEX WTI crude oil (per barrel of oil)	($8.00) to ($11.00)
Henry Hub natural gas (per Mcf)	+$1.00 to $1.50
Income tax rate	37%
Deferred taxes	90% to 95%

* No change from previously announced 2014 Guidance Outlook on September 10, 2013 and most recently reaffirmed on February 26, 2014.

SOURCE Continental Resources

---

http://investors.clr.com/2014-05-07-Continental-Resources-Reports-First-Quarter-2014-Results