UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of report (Date of earliest event reported):
February 26, 2015 (February 24, 2015)

RANGE RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	001-12209	34-1312571
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

100 Throckmorton, Suite 1200 Ft. Worth, Texas	76102
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (817) 870-2601

(Former name or former address, if changed since last report): Not applicable

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

ITEM 2.02 Results of Operations and Financial Condition

On February 24, 2015 Range Resources Corporation issued a press release announcing its 2014 results. A copy of this press release is being furnished as an exhibit to this report on Form 8-K.

ITEM 9.01 Financial Statements and Exhibits

(d) Exhibits:

99.1 Press Release dated February 24, 2015

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

RANGE RESOURCES CORPORATION

By: /s/ *Roger S. Manny*

Roger S. Manny

Chief Financial Officer

Date: February 26, 2015

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press Release dated February 24, 2015

RANGE REPORTS OUTSTANDING 2014 RESULTS

FORT WORTH, TEXAS, FEBRUARY 24, 2015…RANGE RESOURCES CORPORATION (NYSE: RRC) today announced its 2014 financial results.

2014 Highlights –

- Record annual average daily production of 1,162 Mmcfe per day, an increase of 24% over 2013
- Record adjusted annual cash flow of $1 billion, an increase of 10% over 2013
- Unit costs reduced by $0.35 per mcfe or 10% versus 2013
- Total proved reserves increased by 26% to 10.3 Tcfe
- Reserve replacement of 581% at $0.64 per mcfe all-in finding and development cost
- Unrisked resource potential increased to a range of 66 to 87 Tcfe
- Reported net income for 2014 was $634 million versus $116 million in 2013

Production for 2014 averaged 1,162 Mmcfe per day with 32% liquids, a 24% increase over 2013. Fourth quarter 2014 production increased 26% over the prior-year period to 1,277 Mmcfe per day with 31% liquids, another record high for Range and was 6% higher than third quarter 2014. Oil and natural gas liquid (“NGL”) production increased 53% over the prior-year fourth quarter.

Proved reserves increased 26% year-over-year to 10.3 Tcfe, driven by a 1.2 Tcfe increase in proved developed producing reserves. All-in finding and development cost averaged $0.64 per mcfe, while replacing 581% of production from drilling. Drill bit finding cost averaged $0.51 per mcfe in the Marcellus and $0.55 overall. Production and reserves per share on a debt-adjusted basis increased 27% and 29%, respectively. This represents the ninth consecutive year of double-digit per-share, debt-adjusted growth for both production and reserves. Range’s unrisked unproved resource potential at year-end 2014 increased to a range of 66 to 87 Tcfe; including 4.2 billion barrels of NGLs and crude oil/condensate. This resource potential does not include any potential for the Utica.

Commenting, Jeff Ventura, the Company’s Chairman, President and CEO, said, “2014 was a year of significant achievement. We grew production by 24%, while also driving down our cost structure and substantially increasing our capital efficiency. Despite lower prices, cash flow rose 10% to a record level of $1 billion. Our reserves and production per debt adjusted share both grew by more than 25%, as we added over 2 Tcfe of proved reserves, replacing 581% of our production. These results were achieved while also reducing debt over the course of the year.

While we begin 2015 with lower commodity prices, we are well positioned. Besides beginning the year with lower debt, we have extended our credit facility providing over $1 billion of liquidity and we have no bond maturities until 2020. We also expect to continue to lower our cost structure and achieve further capital efficiency gains from longer laterals, technical improvements and by drilling in areas of existing infrastructure. In addition to our strong hedge position, we have NGL projects coming to fruition that have been years in the making, providing us additional marketing opportunities and incremental cash flow. Despite reducing our 2015 capital budget by 46%, we believe we can once again deliver 20% production growth for our shareholders. My confidence is driven by our high quality asset base and our outstanding team here at Range.”

Financial Discussion

(Except for generally accepted accounting principles (“GAAP”) reported amounts, specific expense categories exclude non-cash impairments, unrealized mark-to-market on derivatives, non-cash stock compensation and other items shown separately on the attached tables. “Unit costs” as used in this release are composed of direct operating, transportation, gathering and compression, production and ad valorem tax, general and administrative, interest and depletion, depreciation and amortization costs divided by production. See “Non-GAAP Financial Measures” for a definition of each of the non-GAAP financial measures and the tables that reconcile each of the non-GAAP measures to their most directly comparable GAAP financial measure.)

Full Year 2014

GAAP revenues for 2014 totaled $2.7 billion (46% increase compared to 2013), GAAP net cash provided from operating activities including changes in working capital reached $954 million (28% increase compared to 2013) and GAAP earnings were $634 million ($3.79 per diluted share) versus $116 million ($0.70 per diluted share) in 2013.

Non-GAAP revenues for 2014 totaled $2.0 billion (14% increase compared to 2013), cash flow from operations before changes in working capital, a non-GAAP measure, reached $1.0 billion (10% increase compared to 2013). Adjusted net income comparable to analysts' estimates, a non-GAAP measure, was $260 million ($1.58 per diluted share, a 9% increase over 2013). Wellhead prices, after adjustment for all cash-settled hedges and derivatives, averaged $3.64 per mcfe. The Company's cost structure continued to improve as total unit costs decreased by $0.35 per mcfe or 10% as compared to the prior year.

The Company announced its full year 2014 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates) averaged $4.41 per mcfe, a 10% composite decrease from the prior year. Additional detail on commodity price realizations can be found in the Supplemental Tables provided on the Company's website.

- Production and realized prices by each commodity for 2014 were: natural gas – 786 Mmcf per day ($3.79 per mcf), NGLs – 51,563 barrels per day ($24.31 per barrel) and crude oil and condensate – 11,150 barrels per day ($79.75 per barrel).
- The 2014 average natural gas price improved $0.37 per mcf, before hedging settlements, as compared to the prior year. Financial hedges based upon NYMEX decreased realizations $0.11 per mcf while financial basis hedges decreased realizations $0.09 per mcf primarily driven by extreme cold weather in first quarter 2014. The average Company natural gas differential including the settled financial basis hedges but before NYMEX hedging for 2014 was ($0.48) per mcf compared to ($0.06) per mcf in the prior year.
- NGL pricing, before hedges, was 26% of the West Texas Intermediate index ("WTI") for 2014 compared to 35% of WTI in 2013. The change was primarily a result of removing ethane from the gas stream and adding the production to the NGL mix near the start of 2014.
- Crude oil and condensate price realizations, before hedges, for the year averaged 84% of WTI compared to 88% in 2013.

Fourth Quarter

GAAP revenues for the fourth quarter of 2014 totaled $872 million (104% increase as compared to fourth quarter 2013), GAAP net cash provided from operating activities including changes in working capital reached $299 million (a 24% increase as compared to fourth quarter 2013) and GAAP earnings were $284 million ($1.68 per diluted share) versus earnings of $28 million ($0.17 per diluted share) in the prior-year quarter. Fourth quarter 2014 results included $412 million in derivative gains due to decreased commodity prices, compared to a $59 million loss in 2013. Fourth quarter results also included a $37 million gain in the deferred compensation plan due to decreases in the Company's stock price, while 2013 included an expense of $22 million.

Non-GAAP revenues for fourth quarter 2014 totaled $519 million (13% increase compared to fourth quarter 2013), cash flow from operations before changes in working capital, a non-GAAP measure, reached $273 million. Adjusted net income comparable to analysts' estimates, a non-GAAP measure, was $65 million ($0.39 per diluted share for the fourth quarter 2014). Wellhead prices, after adjustment for all cash-settled hedges and derivatives, averaged $3.39 per mcfe. The Company's total unit costs decreased by $0.37 per mcfe or 11% compared to the prior-year quarter.

Fourth quarter 2014 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates) averaged $4.15 per mcfe, a 13% composite decrease from the prior-year quarter. Additional detail on commodity price realizations can be found in the Supplemental Tables provided on the Company's website.

- Production and realized prices by each commodity for the fourth quarter of 2014 were: natural gas – 886 Mmcf per day ($3.56 per mcf), NGLs – 53,732 barrels per day ($23.33 per barrel) and crude oil and condensate – 11,516 barrels per day ($77.70 per barrel).
- The fourth quarter average natural gas price decreased $0.13 per mcf, before hedging settlements, as compared to the prior-year quarter. Financial hedges based upon NYMEX increased realizations $0.12 per mcf while financial basis hedges increased realizations $0.17 per mcf during the quarter. The average Company natural gas differential including the settled financial basis hedges but before NYMEX hedging for the fourth quarter was ($0.57) per mcf compared to ($0.22) per mcf in the prior year.
- NGL pricing, before hedges, was 25% of WTI for the fourth quarter compared to 37% of WTI in the prior-year quarter. The change was primarily a result of removing ethane from the gas stream and adding the production to the NGL mix near the start of 2014. Fourth quarter NGL price realizations as a percent of WTI improved compared to third quarter 2014 pricing of 23% of WTI. The improvement was largely a result of Range’s ethane being priced mostly off natural gas prices.
- Crude oil and condensate price realizations, before hedges, for the fourth quarter averaged 79% of WTI compared to 86% in the prior-year quarter. Crude oil and condensate realizations for third quarter 2014 were 84% of WTI before hedges.

Financial Position and Liquidity

During 2014, Range decreased total debt by $67 million to $3.1 billion. Total interest expense for the year was $8 million lower than 2013. Total debt consists of long-term notes of $2.4 billion and $723 million outstanding under the Company’s credit facility. The Company’s long-term notes have staggered maturities not starting until 2020. The Company’s revolving credit facility was amended and restated in October 2014, extending the maturity five years. The new agreement has a maximum facility size of $4 billion, an initial borrowing base of $3 billion and $2 billion in commitments. Liquidity under the commitment amount as of December 31, 2014 was $1.2 billion.

Capital Spending and Cost Overview

Fourth quarter drilling expenditures of $410 million funded the drilling of 62 (57 net) wells. Drilling expenditures for 2014 totaled $1.3 billion, and Range drilled 255 (239 net) wells and one recompletion during the year. A 99% success rate was achieved. In addition, during the year, $227 million was spent on acreage purchases, $13 million on gas gathering systems and $59 million on exploration expense. All-in finding and development cost for 2014 averaged $0.64 per mcfe with a reserve replacement ratio of 581%. Drill bit only finding cost averaged $0.55 per mcfe.

Range has set its 2015 capital spending budget at $870 million, a decrease of 46% compared to 2014. The capital budget includes $742 million for drilling and recompletions, $81 million for leasehold and renewals, $42 million for pipelines and facilities and $5 million for seismic. Approximately 95% of the budget will be targeted towards the Marcellus. Range is targeting 20% year-over-year production growth despite the reduction in its capital budget as a result of improving capital efficiencies from its Marcellus activities.

With the reduction in its 2015 capital budget in the Midcontinent, Range has elected to consolidate its Oklahoma City divisional office with its corporate headquarters in Fort Worth. Range will continue to maintain all three of its Midcontinent field offices. The consolidation will allow for improved capital allocation during the year and faster integration of technology improvements across the company. Range expects its annual general and administrative (“G&A”) costs to be reduced by $0.04 per mcfe following the consolidation in the second quarter of 2015.

Total unit costs for 2014 full year decreased by 10%. Direct operating expense, production taxes and transportation expenses totaled $1.22 per mcfe, a decrease of 2% year over year. G&A expense (excluding stock-based compensation) was $0.35 per mcfe, 17% lower than the previous year. Interest expense decreased 22% to $0.40 per mcfe. In total, cash unit costs decreased 10% to $1.97, while depreciation, depletion and amortization expense decreased 10% to $1.30 per mcfe.

Total unit costs for the fourth quarter of 2014 decreased by 11% compared to the prior-year quarter. The improving unit costs were led by a 31% decline in interest expense to $0.33 per mcfe. Direct operating expense, production taxes and transportation expenses totaled $1.18 per mcfe, a decrease of 2% compared to the prior-year quarter. G&A expense (excluding stock-based compensation) was $0.33 per mcfe, 21% lower than the previous year. In total, cash unit costs decreased 12% to $1.84, while depreciation, depletion and amortization expense decreased 8% to $1.25 per mcfe.

Operational Discussion

Range has updated its investor presentation with updated economic sensitivity analysis for the Marcellus. Please see www.rangeresources.com under the Investors tab, "Company Presentations" area, for the presentation entitled, "Company Presentation – February 24, 2015"

Marcellus Shale –

Production for the fourth quarter averaged approximately 1,082 net Mmcfe per day for the Marcellus Shale divisions. Production for 2014 averaged approximately 968 net Mmcfe per day, which represents a 31% increase over the prior year. Fourth quarter net production included 726 Mmcf per day of gas, 50,006 barrels per day of NGLs and 9,333 barrels per day of condensate.

Range has updated well economics and type curves for the planned 2015 Marcellus drilling program, which can be found on the Company's website in the most recent investor presentation. The updated type curves reflect the expected flow restrictions that result from infrastructure and planned facility constraints. The Company manages the development of its Marcellus assets in order to maximize the return of the project. To accomplish this, the infrastructure and facilities are designed to optimize the long-term development of the play, not to maximize the initial production rates of the wells being drilled. As a result, early production from prolific Marcellus wells is often constrained, resulting in flatter decline curves and this is reflected in the updated type curves.

Southern Marcellus Shale Division –

Production for the fourth quarter averaged 823 net Mmcfe per day for the division, a 37% increase over the prior year. The division's fourth quarter net production included 467 Mmcf per day of gas, 50,006 barrels per day of NGLs and 9,271 barrels per day of condensate.

During the fourth quarter, the division brought on line 33 Marcellus wells in southwest Pennsylvania, 29 of which were located in the liquids-rich area of the play. The wells were spread across Washington County. The initial 24-hour production rates of the liquids-rich wells averaged 16.8 (12.9 net) Mmcfe per day, (6.8 Mmcf per day of gas, 1,419 barrels per day of NGLs and 250 barrels per day of condensate), with an average lateral length of 5,091 feet with 26 stages.

In the super-rich area of southwest Pennsylvania the division brought on line 50 wells in 2014. The average 30-day gross production rate of these super-rich wells was 7.8 Mmcfe per day, an 18% increase over the 2013 average. The average lateral length for the wells was 4,770 with 24 stages per lateral. The results demonstrate the quality of acreage as the Company continues development across its 110,000 acre position in this area of the play. In 2015, the Company expects to bring on line 26 wells in the super-rich Marcellus with an average lateral length of 5,367 feet completed with an average of 27 stages. The EUR for the projected 2015 super-rich drilling program is 12.9 Bcfe.

In the wet area of southwest Pennsylvania, where the Company has 220,000 acres, the division brought on line 47 wells in 2014. The average 30-day gross production rate of these wells was 11.3 Mmcfe per day, a 41% increase over the 2013 average. The average lateral length for the wells was 4,520 feet with 23 stages per lateral. The results are further confirmation that improved targeting and completion techniques are increasing expected recoveries across the play. In 2015, the Company expects to bring on line 40 wells in the wet Marcellus with an average lateral length of 5,955 feet completed with an average of 30 stages. The EUR for the projected 2015 drilling program is 17.6 Bcfe.

In the dry area of southwest Pennsylvania, the division brought on line 13 wells in 2014. The average 30-day gross production rate of these wells was 11.2 Mmcf per day, a 92% increase over the 2013 average. The average lateral length for the wells was 4,310 feet with 22 stages per lateral. In 2015, the Company expects to increase activity and bring on 35 wells in the dry Marcellus, as the Company optimizes its drilling plans based on current commodity prices. The average 2015 well design is expected to have an average lateral length of 6,798 feet completed with an average of 34 stages. The EUR for the projected 2015 drilling program in Washington County, PA is 17.1 Bcf.

In 2014, the Company also drilled a successful Utica well beneath its Marcellus position in Washington County, Pennsylvania. The well produced a record 59.0 Mmcf in 24 hours. The well was completed with 32 stages over a 5,420 foot lateral and is currently being produced on an interruptible basis at a restricted rate of approximately 20 Mmcf per day while additional takeaway infrastructure is constructed. A second well on the pad is expected to be drilled in the first half of 2015 and another well is expected in the second half of the year. Range has 400,000 acres in southwest Pennsylvania which it considers prospective for Utica, though the Company has not yet assigned resource potential to its Utica acreage.

Northern Marcellus Shale Division –

In northeast Pennsylvania, production for the fourth quarter averaged 259 net Mmcfe per day, a 22% increase over the prior year. In 2014, the division turned 20 total wells to sales. The average 30-day gross production rate of the 2014 drilling program was 12.8 Mmcf per day, a 48% increase over the 2013 average as the division made significant improvements in lateral placement targeting. The average lateral length for the wells was 4,903 feet and they averaged 25 frac stages per lateral. Importantly, the division reduced total well cost by 30% compared to 2013, while drilling longer laterals. In 2014, the division drilled its best well to date, which produced 25 Mmcf per day over its first 30 days and is expected to ultimately recover 17 Bcf of natural gas.

Range is currently running one rig in northeast Pennsylvania to maintain continuous drilling commitments under the leases. In 2015, the Company expects to turn 14 wells to sales in northern Marcellus. Drilling activity during the year is expected to average lateral lengths of 5,663 feet and 28 frac stages. The projected EUR for the projected 2015 drilling program is 15.2 Bcf.

Marcellus Shale Marketing and Transportation Review –

In December 2014, Range confirmed the Mariner East propane pipeline was commissioned. Range has delivered its share (80%) of approximately 133,000 barrels of propane line fill into the pipeline while the operator completes work at the Marcus Hook Industrial Complex. Range expects to expand its sales in the favorable local markets and potentially in the international markets while the refrigeration and other facilities are being completed at Marcus Hook. Utilization of the Mariner East propane pipeline is expected to lower Range’s cost of propane deliveries by approximately $0.20 per gallon when compared to 2014. This reduction in transportation cost is expected to add significant value to the net realized price of propane in 2015 which could approach an additional $50 million in cash flow on an annualized basis when the facilities are fully operational in the second half of the year.

Range also announced that the Company entered into a multi-year contract to sell 5,000 barrels per day of ethane on the Gulf Coast. This contract represents half of the Company’s existing committed ATEX transportation volume. Commencing January 1, 2015, ethane was being sold under this contract based on a natural gas equivalent index. All of Range's ethane sales contracts provide for better than natural gas equivalent pricing and are multi-year contracts. These contracts put Range in a unique situation where extracting ethane enhances cash flow since these contracts were largely executed before ethane prices on the Gulf Coast dropped to their current levels.

The ATEX pipeline issued a *force majeure* notice on January 26, 2015 due to a disruption in service. The pipeline was placed back into service in mid-February on a limited capacity basis. It is currently unknown as to how much volume the pipeline will be able to transport and how long the limited capacity requirements will be required by the regulatory agencies. Range believes that all its commitments to contracted customers can be met, but production in the first quarter is expected to be reduced. However, our full year targeted production growth of 20% remains intact. Range currently has access to two ethane pipelines – ATEX transporting to the Gulf Coast and Mariner West serving customers in Sarnia, Canada. In July 2015, Range expects a third pipeline, Mariner East, will commence operations transporting ethane to the Marcus Hook Industrial Complex in Philadelphia for export to Europe under an existing sales contract.

Southern Appalachia Division –

Production for the fourth quarter averaged 108 net Mmcf per day for the division, a 48% increase from the prior year due to the mid-year property exchange.

In 2014, Range gained complete operational control over its Nora assets in Virginia. With this control, the Southern Appalachia division focused on drilling a mix of coalbed methane ("CBM"), tight gas and horizontal Huron Shale wells along with focus on the sizable inventory of low cost, high return recompletions and workovers. In 2014 the division drilled 27 CBM, 17 tight gas and 8 horizontal Huron wells for a total of 52 (51 net) wells. Production for the year averaged 91.4 Mmcf per day net for the division, a 26% increase over the prior year. The division continued development of the multi-pay horizons on its 465,000 net acre position while introducing new completion techniques and well designs resulting in improved well performance. Because of these improvements, the CBM wells drilled in 2014 are the best group of CBM wells in over 20 years in Nora. In addition to these new completion techniques resulting in higher rates of return, Range receives the added economic benefit of owning the royalty for wells drilled on its fee mineral acreage. The Virginia assets are also strategically located to supply gas to the growing southeast markets along the Atlantic Coast where Range receives $0.20 above NYMEX for production from the Nora field.

Capital spending for Southern Appalachia Division will be targeted to roughly maintain its production levels for the year. The division has the lowest natural decline rate of any of Range's operating areas due to its CBM production.

Midcontinent Division –

Production for the fourth quarter averaged 82 net Mmcfe per day for the division, an 8% decrease from the prior year. The division's fourth quarter production included 47.9 Mmcf per day of gas, 3,625 barrels per day of NGLs and 2,112 barrels per day of oil.

In 2014, Range continued to test the geologic modeling of its Mississippian Chat acreage along the Nemaha Ridge, successfully expanding the play to the north. The division turned 16 Mississippian Chat wells to sales in 2014. The 2014 wells had 30 day rates that were 30% better than 2013 as the Company improved its geological targeting and refined its completion design. In 2015 the Company plans to bring eight Mississippian Chat wells on line.

<u>Guidance – 2015</u>

Production per day Guidance:

Production growth for 2015 is targeted at 20% year-over-year. Production for the first quarter of 2015 is expected to be approximately 1.30 Bcfe per day.

Guidance for 2015 Activity:

Under the current plan, Range expects to turn to sales approximately 148 wells during 2015, as shown below.

	Planned Wells to Sales in 2015
Super-Rich area	26
Wet area	40
Dry area (NE & SW)	49
Total Marcellus	115
Nora area	25
Midcontinent	8
Total	148

1Q 2015 Expense Guidance:

Direct operating expense:	$0.31 - $0.33 per mcfe
Transportation, gathering and compression expense:	$0.78 - $0.82 per mcfe
Production tax expense:	$0.09 - $0.10 per mcfe
Exploration expense:	$9 - $11 million
Unproved property impairment expense:	$12 - $14 million
G&A expense:	$0.33 - $0.35 per mcfe
Interest expense:	$0.33 - $0.34 per mcfe
DD&A expense:	$1.24 - $1.26 per mcfe

Hedging Status

Range hedges portions of its expected future production volumes to increase the predictability of cash flow and to help maintain a strong, flexible financial position. Range currently has over 60% of its expected 2015 natural gas production hedged at a weighted average floor price of $4.00 per mcf. Similarly, Range has hedged approximately 75% of its 2015 projected crude oil production at a floor price of $90.57 and approximately 40% of its composite NGL production. Please see Range's detailed hedging schedule posted at the end of the financial tables below and on its website at www.rangeresources.com.

Range has also hedged Marcellus and other basis differentials covering 95,000 Mmbtu per day from January through March 2015, and 170,000 for April 2015 through October 2015. The fair value of the basis hedges based upon future strip prices as of December 31, 2014 was a gain of $1.7 million.

Conference Call Information

A conference call to review the financial results is scheduled on Wednesday, February 25 at 9:00 a.m. ET. To participate in the call, please dial 877-407-0778 and ask for the Range Resources 2014 financial results conference call. A replay of the call will be available through March 25. To access the phone replay dial 877-660-6853. The conference ID is 13599281.

A simultaneous webcast of the call may be accessed at www.rangeresources.com. The webcast will be archived for replay on the Company's website until March 25.

Non-GAAP Financial Measures:

Adjusted net income comparable to analysts' estimates as set forth in this release represents income or loss from operations before income taxes adjusted for certain non-cash items (detailed below and in the accompanying table) less income taxes. We believe adjusted net income comparable to analysts' estimates is calculated on the same basis as analysts' estimates and that many investors use this published research in making investment decisions and evaluating operational trends of the Company and its performance relative to other oil and gas producing companies. Diluted earnings per share (adjusted) as set forth in this release represents adjusted net income comparable to analysts' estimates on a diluted per share basis. A table is included which reconciles income or loss from operations to adjusted net income comparable to analysts' estimates and diluted earnings per share (adjusted). On its website, the Company provides additional comparative information on prior periods along with non-GAAP revenue disclosures.

Cash flow from operations before changes in working capital (sometimes referred to as "adjusted cash flow") as defined in this release represents net cash provided by operations before changes in working capital and exploration expense adjusted for certain non-cash compensation items. Cash flow from operations before changes in working capital is widely accepted by the investment community as a financial indicator of an oil and gas company's ability to generate cash to internally fund exploration and development activities and to service debt. Cash flow from operations before changes in working capital is also useful because it is widely used by professional research analysts in valuing, comparing, rating and providing investment recommendations of companies in the oil and gas exploration and production industry. In turn, many investors use this published research in making investment decisions. Cash flow from operations before changes in working capital is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operations, investing, or financing activities as an indicator of cash flows, or as a measure of liquidity. A table is included which reconciles Net cash provided by operations to Cash flow from operations before changes in working capital as used in this release. On its website, the Company provides additional comparative information on prior periods for cash flow, cash margins and non-GAAP earnings as used in this release.

The cash prices realized for oil and natural gas production including the amounts realized on cash-settled derivatives and net of transportation, gathering and compression expense is a critical component in the Company's performance tracked by investors and professional research analysts in valuing, comparing, rating and providing investment recommendations and forecasts of companies in the oil and gas exploration and production industry. In turn, many investors use this published research in making investment decisions. Due to the GAAP disclosures of various derivative transactions and third party transportation, gathering and compression expense, such information is now reported in various lines of the income statement. The Company believes that it is important to furnish a table reflecting the details of the various components of each income statement line to better inform the reader of the details of each amount and provide a summary of the realized cash-settled amounts and third party transportation, gathering and compression expense which historically were reported as natural gas, NGLs and oil sales. This information will serve to bridge the gap between various readers' understanding and fully disclose the information needed.

The Company discloses in this release the detailed components of many of the single line items shown in the GAAP financial statements included in the Company's Form 10-K. The Company believes that it is important to furnish this detail of the various components comprising each line of the Statements of Operations to better inform the reader of the details of each amount, the changes between periods and the effect on its financial results.

Range has disclosed two primary metrics in this release to measure our ability to establish a long-term trend of adding reserves at a reasonable cost – a reserve replacement ratio and finding and development cost per unit. The reserve replacement ratio is an indicator of our ability to replace annual production volumes and grow our reserves. It is important to economically find and develop new reserves that will offset produced volumes and provide for future production given the inherent decline of hydrocarbon reserves as they are produced. We believe the ability to develop a competitive advantage over other natural gas and oil companies is dependent on adding reserves in our core areas at lower costs than our competition. The reserve replacement ratio is calculated by dividing production for the year into the total of proved extensions, discoveries and additions and proved reserves added by performance revisions.

Finding and development cost per unit is a non-GAAP metric used in the exploration and production industry by companies, investors and analysts. The calculations presented by the Company are based on estimated and unaudited costs incurred excluding asset retirement obligations and divided by proved reserve additions (extensions, discoveries and additions shown in the table) adjusted for the changes in proved reserves for acreage, acquisitions, performance revisions and/or price revisions as stated in each instance in the release. Drill bit development cost per mcfe is based on estimated and unaudited drilling, development and exploration costs incurred divided by the total of reserve additions and performance revisions. These calculations do not include the future development costs required for the development of proved undeveloped reserves. The SEC method of computing finding costs contains additional cost components and results in a higher number. A reconciliation of the two methods is shown on our website at www.rangeresources.com.

The reserve replacement ratio and finding and development cost per unit are statistical indicators that have limitations, including their predictive and comparative value. As an annual measure, the reserve replacement ratio can be limited because it may vary widely based on the extent and timing of new discoveries and the varying effects of changes in prices and well performance. In addition, since the reserve replacement ratio and finding and development cost per unit do not consider the cost or timing of future production of new reserves, such measures may not be an adequate measure of value creation. These reserves metrics may not be comparable to similarly titled measurements used by other companies.

Year-end pre-tax discounted present value is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of pre-tax discounted present value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We further believe investors and creditors use pre-tax discounted present value as a basis for comparison of the relative size and value of our reserves as compared with other companies. Range's pre-tax discounted present value as of December 31, 2014 may be reconciled to its standardized measure of discounted future net cash flows as of December 31, 2014 by reducing Range's pre-tax discounted present value by the discounted future income taxes associated with such reserves.

Reconciliation of PV-10
($ in millions) (unaudited)

	December 31, 2014
Standardized measure of discounted future net of cash flows	$ 7,593
Discounted future cash flows for income taxes	2,477
Discounted future net cash flows before income taxes (PV-10)	$ 10,070

Range has disclosed a debt-adjusted per share metric in this release to measure per-share growth of production and reserves. This debt-adjusted metric keeps the debt-to-capitalization ratio unchanged during the calculation period. To achieve a constant debt-to-capitalization ratio, the share count is adjusted to increase/decrease equity from the actual end-of-year to the beginning of period level debt-to-capitalization. This adjustment is made by dividing the necessary increase/decrease in equity by the average common share price during the year for production (year-end price for reserves) to arrive at shares issued/repurchased. The production or reserves are then divided by this adjusted share count to reach the debt-adjusted per share results.

Hedging and Derivatives

In this news release, Range has reclassified within total revenues its financial reporting of the cash settlement of its commodity derivatives. Under this presentation those hedges considered "effective" under ASC 815 are included in "Natural gas, NGLs and oil sales" when settled. For those hedges designated to regions where the historical correlation between NYMEX and regional prices is "non-highly effective" or is "volumetric ineffective" due to sale of the underlying reserves, they are deemed to be "derivatives" and the cash settlements are included in a separate line item shown as "Derivative fair value income (loss)" in the consolidated statements of operations included in the Company's Form 10-K along with the change in mark-to-market valuations of open derivative positions. The Company has provided additional information regarding natural gas, NGLs and oil sales in a supplemental table included with this release, which would correspond to amounts shown by analysts for natural gas, NGLs and oil sales realized, including cash-settled derivatives.

RANGE RESOURCES CORPORATION (NYSE: RRC) is a leading independent oil and natural gas producer with operations focused in Appalachia and the Midcontinent region of the United States. The Company pursues an organic growth strategy targeting high return, low-cost projects within its large inventory of low risk, development drilling opportunities. The Company is headquartered in Fort Worth, Texas. More information about Range can be found at www.rangeresources.com.

All statements, except for statements of historical fact, made in this release regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future liquidity, production growth, completion of ethane projects, estimated gas in place, future rates of return, future low costs, low reinvestment risk, future earnings and per-share value, future capital spending plans, increasing capital efficiency, well-positioned, continued utilization of existing infrastructure, gas marketability, maximized realized natural gas prices, acreage quality, access to multiple gas markets, expected drilling and development plans, improved capital efficiency, future financial position, future technical improvements, future marketing opportunities and future guidance information are 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. These statements are based on assumptions and estimates that management believes are reasonable based on currently available information; however, management's assumptions and Range's future performance are subject to a wide range of business risks and uncertainties and there is no assurance that these goals and projections can or will be met. Any number of factors could cause actual results to differ materially from those in the forward-looking statements, including, but not limited to, the volatility of oil and gas prices, the results of our hedging transactions, the costs and results of actual drilling and operations, the timing of production, mechanical and other inherent risks associated with oil and gas production, weather, the availability of drilling equipment, changes in interest rates, litigation, uncertainties about reserve estimates, environmental risks and regulatory changes. Range undertakes no obligation to publicly update or revise any forward-looking statements. Further information on risks and uncertainties is available in Range's filings with the Securities and Exchange Commission ("SEC"), which are incorporated by reference.

The SEC permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions as well as the option to disclose probable and possible reserves. Range has elected not to disclose the Company's probable and possible reserves in its filings with the SEC. Range uses certain broader terms such as "resource potential," "unrisked resource potential," "unproved resource potential" or "upside" or other descriptions of volumes of resources potentially recoverable through additional drilling or recovery techniques that may include probable and possible reserves as defined by the SEC's guidelines. Range has not attempted to distinguish probable and possible reserves from these broader classifications. The SEC's rules prohibit us from including in filings with the SEC these broader classifications of reserves. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of actually being realized. Unproved resource potential refers to Range's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques and have not been reviewed by independent engineers. Unproved resource potential does not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System and does not include proved reserves. Area wide unproven resource potential has not been fully risked by Range's management. "EUR," or estimated ultimate recovery, refers to our management's estimates of hydrocarbon quantities that may be recovered from a well completed as a producer in the area. These quantities may not necessarily constitute or represent reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or the SEC's oil and natural gas disclosure rules. Actual quantities that may be recovered from Range's interests could differ substantially. Factors affecting ultimate recovery include the scope of Range's drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, field spacing rules, recoveries of gas in place, length of horizontal laterals, actual drilling results, including geological and mechanical factors affecting recovery rates and other factors. Estimates of resource potential may change significantly as development of our resource plays provides additional data.

In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Investors are urged to consider closely the disclosure in our most recent Annual Report on Form 10-K, available from our website at www.rangeresources.com or by written request to 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. You can also obtain this Form 10-K on the SEC's website at www.sec.gov or by calling the SEC at 1-800-SEC-0330.

2015-04

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RANGE RESOURCES CORPORATION

STATEMENTS OF INCOME
Based on GAAP reported earnings with additional details of items included in each line in Form 10-K
(Audited, in thousands, except per share data)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2014	2013	%	2014	2013	%
Revenues and other income:						
Natural gas, NGLs and oil sales (a)	$416,388	$448,545		$1,911,989	$1,715,676	
Derivative fair value income/(loss)	412,422	(59,355)		383,520	(61,825)	
Gain on sale of assets	3,760	3,162		285,638	92,291	
Brokered natural gas, marketing and other (b)	31,424	14,809		123,065	55,546	
Brokered natural gas – blending (b)	—	22,535		—	62,751	
Equity method investment (b)	—	(79)		(277)	462	
ARO settlement gain (loss) (b)	8,196	(1,924)		7,545	(2,938)	
Other (b)	24	393		215	756	
Total revenues and other income	872,214	428,086	104%	2,711,695	1,862,719	46%
Costs and expenses:						
Direct operating	37,262	33,661		146,275	125,336	
Direct operating – non-cash stock-based compensation (c)	699	699		4,208	2,755	
Transportation, gathering and compression	89,542	66,820		325,289	256,242	
Production and ad valorem taxes	11,923	11,290		44,555	45,240	
Brokered natural gas and marketing	31,161	15,344		126,457	60,113	
Brokered natural gas and marketing – non-cash stock- based compensation (c)	1,209	542		3,523	1,852	
Brokered natural gas and marketing – blending	—	25,806		—	69,821	
Exploration	22,477	13,053		58,979	60,384	
Exploration – non-cash stock-based compensation (c)	1,161	1,012		4,569	4,025	
Abandonment and impairment of unproved properties	14,308	5,852		47,079	51,918	
General and administrative	39,034	38,740		148,888	143,265	
General and administrative – non-cash stock-based compensation (c)	11,526	21,137		55,382	55,737	
General and administrative – lawsuit settlements	804	330		3,007	91,919	
General and administrative – bad debt expense	—	—		250	250	
General and administrative – DEP penalty	999	—		5,899	—	
Termination costs	5,372	—		5,372	—	
Termination costs – non-cash stock-based compensation (c)	2,999	—		2,999	—	
Deferred compensation plan (d)	(36,836)	22,039		(74,550)	55,296	
Interest expense	38,900	44,955		168,977	176,557	
Loss on early extinguishment of debt	—	—		24,596	12,280	
Depletion, depreciation and amortization	146,539	126,958		551,032	492,397	
Impairment of proved properties and other assets	3,033	—		28,024	7,753	
Total costs and expenses	422,112	428,238	-1%	1,680,810	1,713,140	-2%
Income before income taxes	450,102	(152)	nm	1,030,885	149,579	589%
Income tax expense (benefit):						
Current	(4)	(143)		1	(143)	
Deferred	166,052	(28,180)		396,502	34,000	
	166,048	(28,323)		396,503	33,857	
Net income	$284,054	$ 28,171	908%	$ 634,382	$ 115,722	448%
Net Income Per Common Share:						
Basic	$ 1.68	$ 0.17		$ 3.81	$ 0.71	
Diluted	$ 1.68	$ 0.17		$ 3.79	$ 0.70	
Weighted average common shares outstanding, as reported:						
Basic	165,877	160,555	3%	163,625	160,438	2%
Diluted	166,164	161,496	3%	164,403	161,407	2%

(a) See separate natural gas, NGLs and oil sales information table.
(b) Included in Brokered natural gas, marketing and other revenues in the 10-K.
(c) Costs associated with stock compensation and restricted stock amortization, which have been reflected in the categories associated with the direct personnel costs, and are combined with the cash costs in the 10-K.
(d) Reflects the change in market value of the vested Company stock held in the deferred compensation plan.

RANGE RESOURCES CORPORATION

BALANCE SHEETS
(In thousands)

	December 31, 2014 (Audited)	December 31, 2013 (Audited)
Assets		
Current assets	$ 207,243	$ 192,466
Derivative assets	363,049	4,421
Deferred tax assets	—	51,414
Natural gas and oil properties, successful efforts method	7,977,573	6,758,437
Transportation and field assets	37,581	32,784
Other	161,334	259,564
	$8,746,780	$7,299,086
Liabilities and Stockholders' Equity		
Current liabilities	$ 740,197	$ 464,326
Asset retirement obligations	15,067	5,037
Derivative liabilities	—	26,198
Bank debt	723,000	500,000
Subordinated notes	2,350,000	2,640,516
	3,073,000	3,140,516
Deferred tax liability	997,494	771,980
Derivative liabilities	—	25
Deferred compensation liability	178,599	247,537
Asset retirement obligations and other liabilities	284,994	229,015
	1,461,087	1,248,557
Common stock and retained earnings	3,460,517	2,411,853
Common stock held in treasury stock	(3,088)	(3,637)
	3,457,429	2,408,216
Accumulated other comprehensive income	—	6,236
Total stockholders' equity	3,457,429	2,414,452
	$8,746,780	$7,299,086

RECONCILIATION OF TOTAL REVENUES AND OTHER INCOME TO TOTAL REVENUE EXCLUDING CERTAIN ITEMS, a non-GAAP measure
(Unaudited, in thousands)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2014	2013	%	2014	2013	%
Total revenues and other income, as reported	$ 872,214	$428,086	104%	$2,711,695	$1,862,719	46%
Adjustment for certain special items:						
Total change in fair value related to derivatives prior to settlement (gain) loss	(341,197)	56,434		(426,154)	30,569	
ARO settlement (gain) loss	(8,196)	1,924		(7,545)	2,938	
(Gain) loss on sale of assets	(3,760)	(3,162)		(285,638)	(92,291)	
Brokered natural gas – blending	—	(22,535)		—	(62,751)	
Total revenues, as adjusted, non-GAAP	$ 519,061	$460,747	13%	$1,992,358	$1,741,184	14%

RANGE RESOURCES CORPORATION

CASH FLOWS FROM OPERATING ACTIVITIES
(Audited, in thousands)

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Net income	$ 284,054	$ 28,171	$ 634,382	$ 115,722
Adjustments to reconcile net income to cash provided from continuing operations:				
(Gain) loss from equity investment, net of distributions	(1)	(1,799)	3,095	(2,973)
Deferred income tax expense (benefit)	166,052	(28,180)	396,502	34,000
Depletion, depreciation, amortization and impairment	149,572	126,958	579,056	500,150
Exploration dry hole and impairment costs	16,144	1,795	16,145	5,699
Abandonment and impairment of unproved properties	14,308	5,852	47,079	51,918
Derivative fair value (income) loss	(412,422)	59,355	(383,520)	61,825
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	71,225	(2,921)	(42,634)	(31,256)
Allowance for bad debts	—	—	250	250
Amortization of deferred issuance costs, loss on extinguishment of debt and other	(6,736)	4,131	24,694	23,866
Deferred and stock-based compensation	(19,781)	45,211	(4,295)	119,398
Gain on sale of assets	(3,760)	(3,162)	(285,638)	(92,291)
Changes in working capital:				
Accounts receivable	(18,427)	(27,720)	(5,329)	(21,212)
Inventory and other	814	526	(4,521)	3,785
Accounts payable	12,332	15,679	(1,023)	(13,555)
Accrued liabilities and other	45,823	16,776	(20,108)	(11,788)
Net changes in working capital	40,542	5,261	(30,981)	(42,770)
Net cash provided from operating activities	$ 299,197	$ 240,672	$ 954,135	$ 743,538

RECONCILIATION OF NET CASH PROVIDED FROM OPERATING ACTIVITIES, AS REPORTED, TO CASH FLOW FROM OPERATIONS BEFORE CHANGES IN WORKING CAPITAL, a non-GAAP measure
(Unaudited, in thousands)

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Net cash provided from operating activities, as reported	$299,197	$240,672	$ 954,135	$743,538
Net changes in working capital	(40,542)	(5,261)	30,981	42,770
Exploration expense	6,333	11,258	42,834	54,685
Lawsuit settlements	804	330	3,007	91,919
DEP penalty	999	—	5,899	—
Equity method investment distribution / intercompany elimination	—	1,877	(2,819)	2,509
Loss on gas blending	—	3,271	—	7,070
Termination costs	5,372	—	5,372	—
Non-cash compensation adjustment	661	331	907	767
Cash flow from operations before changes in working capital – a non-GAAP measure	$272,824	$252,478	$1,040,316	$943,258

ADJUSTED WEIGHTED AVERAGE SHARES OUTSTANDING
(Audited, in thousands)

	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Twelve Months Ended December 31, 2014	Twelve Months Ended December 31, 2013
Basic:				
Weighted average shares outstanding	168,705	163,425	166,439	163,223
Stock held by deferred compensation plan	(2,828)	(2,870)	(2,814)	(2,785)
Adjusted basic	165,877	160,555	163,625	160,438
Dilutive:				
Weighted average shares outstanding	168,705	163,425	166,439	163,223
Dilutive stock options under treasury method	(2,541)	(1,929)	(2,036)	(1,816)
Adjusted dilutive	166,164	161,496	164,403	161,407

RANGE RESOURCES CORPORATION

RECONCILIATION OF NATURAL GAS, NGLs AND OIL SALES AND DERIVATIVE FAIR VALUE INCOME (LOSS) TO CALCULATED CASH REALIZED NATURAL GAS, NGLs AND OIL PRICES WITH AND WITHOUT THIRD PARTY TRANSPORTATION, GATHERING AND COMPRESSION FEES

non-GAAP measures

(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2014	2013	%	2014	2013	%
Natural gas, NGL and oil sales components:						
Natural gas sales	$ 266,475	$ 236,497		$ 1,140,989	$ 954,673	
NGL sales	88,792	103,797		444,152	315,272	
Oil sales	61,479	86,125		316,625	329,182	
Cash-settled hedges (effective):						
Natural gas	(2,074)	20,255		4,686	110,948	
Crude oil	1,716	1,871		5,537	5,601	
Total oil and gas sales, as reported	$ 416,388	$ 448,545	-7%	$ 1,911,989	$ 1,715,676	11%
Derivative fair value income (loss), as reported:	$ 412,422	$ (59,355)		$ 383,520	$ (61,825)	
Cash settlements on derivative financial instruments – gain (loss):						
Natural gas	(25,541)	(10,268)		58,442	8,090	
NGLs	(26,551)	10,807		(13,437)	12,566	
Crude Oil	(19,133)	2,382		(2,371)	10,600	
Total change in fair value related to derivatives prior to settlement, a non GAAP measure	$ 341,197	$ (56,434)		$ 426,154	$ (30,569)	
Transportation, gathering and compression components:						
Natural gas	$ 76,682	$ 63,556		$ 282,446	$ 243,127	
NGLs	12,860	3,264		42,843	13,115	
Total transportation, gathering and compression, as reported	$ 89,542	$ 66,820		$ 325,289	$ 256,242	
Natural gas, NGL and oil sales, including cash-settled derivatives: (c)						
Natural gas sales	$ 289,942	$ 267,020		$ 1,087,233	$ 1,057,531	
NGL sales	115,343	92,990		457,589	302,706	
Oil sales	82,328	85,614		324,533	324,183	
Total	$ 487,613	$ 445,624	9%	$ 1,869,355	$ 1,684,420	11%
Production of oil and gas during the periods (a):						
Natural gas (mcf)	81,481,720	69,553,207	17%	286,926,099	264,528,254	8%
NGL (bbl)	4,943,309	2,887,548	71%	18,820,526	9,254,801	103%
Oil (bbl)	1,059,514	1,032,299	3%	4,069,568	3,827,491	6%
Gas equivalent (mcfe) (b)	117,498,658	93,072,289	26%	424,266,663	343,022,006	24%
Production of oil and gas – average per day (a):						
Natural gas (mcf)	885,671	756,013	17%	786,099	724,735	8%
NGL (bbl)	53,732	31,386	71%	51,563	25,356	103%
Oil (bbl)	11,516	11,221	3%	11,150	10,486	6%
Gas equivalent (mcfe) (b)	1,277,159	1,011,655	26%	1,162,374	939,786	24%
Average prices, including cash-settled hedges that qualify for hedge accounting before third party transportation costs:						
Natural gas (mcf)	$ 3.24	$ 3.69	-12%	$ 3.99	$ 4.03	-1%
NGL (bbl)	$ 17.96	$ 35.95	-50%	$ 23.60	$ 34.07	-31%
Oil (bbl)	$ 59.65	$ 85.24	-30%	$ 79.16	$ 87.47	-9%
Gas equivalent (mcfe) (b)	$ 3.54	$ 4.82	-26%	$ 4.51	$ 5.00	-10%
Average prices, including cash-settled hedges and derivatives before third party transportation costs: (c)						
Natural gas (mcf)	$ 3.56	$ 3.84	-7%	$ 3.79	$ 4.00	-5%
NGL (bbl)	$ 23.33	$ 32.20	-28%	$ 24.31	$ 32.71	-26%
Oil (bbl)	$ 77.70	$ 82.94	-6%	$ 79.75	$ 84.70	-6%
Gas equivalent (mcfe) (b)	$ 4.15	$ 4.79	-13%	$ 4.41	$ 4.91	-10%
Average prices, including cash-settled hedges and derivatives: (d)						
Natural gas (mcf)	$ 2.62	$ 2.93	-11%	$ 2.80	$ 3.08	-9%
NGL (bbl)	$ 20.73	$ 31.07	-33%	$ 22.04	$ 31.29	-30%
Oil (bbl)	$ 77.70	$ 82.94	-6%	$ 79.75	$ 84.70	-6%
Gas equivalent (mcfe) (b)	$ 3.39	$ 4.07	-17%	$ 3.64	$ 4.16	-13%
Transportation, gathering and compression expense per mcfe	$ 0.76	$ 0.72	6%	$ 0.77	$ 0.75	3%

(a) Represents volumes sold regardless of when produced.

(b) Oil and NGLs are converted at the rate of one barrel equals six mcfe based upon the approximate relative energy content of oil to natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

(c) Excluding third party transportation, gathering and compression costs.

(d) Net of transportation, gathering and compression costs.

RANGE RESOURCES CORPORATION

RECONCILIATION OF INCOME (LOSS) BEFORE INCOME TAXES
AS REPORTED TO INCOME BEFORE INCOME TAXES
EXCLUDING CERTAIN ITEMS, a non-GAAP measure
(Unaudited, in thousands, except per share data)

	Three Months Ended December 31,			Twelve Months Ended December 31,		
	2014	2013	%	2014	2013	%
Income (loss) before income taxes, as reported	$ 450,102	$ (152)	nm	$1,030,885	$149,579	589%
Adjustment for certain special items:						
(Gain) loss on sale of assets	(3,760)	(3,162)		(285,638)	(92,291)	
(Gain) loss on ARO settlements	(8,196)	1,924		(7,545)	2,938	
Change in fair value related to derivatives prior to settlement	(341,197)	56,434		(426,154)	30,569	
Abandonment and impairment of unproved properties	14,308	5,852		47,079	51,918	
Loss on gas blending – brokered natural gas and marketing	—	3,271		—	7,070	
Loss on early extinguishment of debt	—	—		24,596	12,280	
Impairment of proved property and other assets	3,033	—		28,024	7,753	
Lawsuit settlements	804	330		3,007	91,919	
DEP penalty	999	—		5,899	—	
Termination costs	5,372	—		5,372	—	
Termination costs – non-cash stock-based compensation	2,999	—		2,999	—	
Brokered natural gas and marketing – non-cash stock-based compensation	1,209	542		3,523	1,852	
Direct operating – non-cash stock-based compensation	699	699		4,208	2,755	
Exploration expenses – non-cash stock-based compensation	1,161	1,012		4,569	4,025	
General & administrative – non-cash stock-based compensation	11,526	21,137		55,382	55,737	
Deferred compensation plan – non-cash adjustment	(36,836)	22,039		(74,550)	55,296	
Income before income taxes, as adjusted	102,223	109,926	-7%	421,656	381,400	11%
Income tax expense (benefit), as adjusted						
Current	(4)	(143)		1	(143)	
Deferred	37,680	41,772		161,460	147,705	
Net income excluding certain items, a non-GAAP measure	$ 64,547	$ 68,297	-5%	$ 260,195	$233,838	11%
Non-GAAP income per common share						
Basic	$ 0.39	$ 0.43	-9%	$ 1.59	$ 1.46	9%
Diluted	$ 0.39	$ 0.42	-7%	$ 1.58	$ 1.45	9%
Non-GAAP diluted shares outstanding, if dilutive	166,164	161,496		164,403	161,407	

HEDGING POSITION AS OF FEBRUARY 11, 2015 –
(Unaudited)

	Daily Volume	Hedge Price
Gas		
2015 Swaps	503,897 Mmbtu	$3.98
2015 Collars	145,000 Mmbtu	$4.07 – $4.56
2016 Swaps	340,000 Mmbtu	$3.61
Oil		
2015 Swaps	9,626 bbls	$90.57
2016 Swaps	1,000 bbls	$91.43
C3 Propane		
2015 Swaps	10,473 bbls	$0.62/gallon
C4 Normal Butane		
2015 Swaps	1,819 bbls	$0.70/gallon
C5 Natural Gasoline		
2015 Swaps	1,942 bbls	$1.21/gallon

NOTE: SEE WEBSITE FOR OTHER SUPPLEMENTAL INFORMATION FOR THE PERIODS