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, 2019 (February 25, 2019)

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 Street, Suite 1200 Fort 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))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

ITEM 2.02 Results of Operations and Financial Condition

On February 25, 2019 Range Resources Corporation issued a press release announcing its 2018 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 25, 2019

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/ Mark S. Scucchi
Mark S. Scucchi
Chief Financial Officer

Date: February 26, 2019

Exhibit 99.1

NEWS RELEASE

RANGE ANNOUNCES FOURTH QUARTER AND YEAR-END 2018 RESULTS

FORT WORTH, TEXAS, FEBRUARY 25, 2019…RANGE RESOURCES CORPORATION (NYSE: RRC) today announced its fourth quarter and year-end 2018 financial results.

Commenting on the results and 2019 plans, Jeff Ventura, the Company's CEO said, "Range made solid progress on key strategic objectives in 2018. Our capital spending was disciplined, coming in $31 million under budget due to efficient operations, longer laterals and innovative water recycling. For the year, Range generated free cash flow, reduced absolute debt, and also made good progress on our leverage targets with contribution of the royalty sale announced in late 2018.

I believe the Company is positioned well, with a high-quality resource base capable of generating sustainable free cash at current strip prices. Our economic resilience is further demonstrated in the year-end PV10 reserve value of $9.9 billion using futures strip pricing from year-end, which equates to approximately $24 per share, net of debt. Going forward, Range is committed to translating well-level returns from our high-quality asset base into corporate-level returns, including a free cash flow yield that is competitive not only within energy, but across the broader market."

2019 Capital Spending Plans

Range's 2019 capital budget is approximately $756 million. At strip pricing, cash flow is projected to exceed spending for the year. Excess cash flow is expected to be used to reduce debt. In addition, asset sales are being pursued to further strengthen the balance sheet.

The Company expects production to average between 2,325 to 2,345 Mmcfe per day in 2019, with 30% attributed to liquids production. Approximately 90% of the capital budget is expected to be allocated to the Appalachia division and the remainder to the North Louisiana division. In Appalachia, over 60% of activity is planned to be directed towards liquids-rich drilling, where Range's acreage has an extensive inventory of existing pads that reduce capital costs and gathering expenses. The liquids-rich acreage is also in close proximity to recently built infrastructure for both natural gas takeaway and natural gas liquids ("NGL") processing.

The 2019 capital budget includes approximately $685 million for drilling and recompletions (91% of the total), $51 million for leasehold, and $20 million for pipelines, facilities and other capital expenditures. The budget includes 88 wells expected to be brought on line during the year in the Marcellus and eight wells in North Louisiana. Similar to the 2018 program, approximately half of the 2019 Marcellus wells are planned to be drilled from existing pads.

2018 Capital Expenditures

Fourth quarter 2018 drilling expenditures of $158 million funded the drilling of 17 wells. Drilling expenditures for the full year totaled $836 million and funded the drilling of 104 (100 net) wells during 2018. A 100% success rate was achieved. In addition, during 2018, $62 million was spent on acreage purchases and $10 million on gas gathering systems. Total capital expenditures in 2018 were approximately $910 million, which was $31 million under budget for the year.

2018 Proved Reserves Results

Range previously announced 2018 proved reserves results on February 11, 2019. Highlights from the announcement were:

- 2018 PV10 value of reserves using year-end future strip prices was $9.9 billion
- Year-end 2018 SEC PV10 value of proved reserves was $13.2 billion, up $5.1 billion from prior year
- Proved reserves increased by 18% from the prior-year to 18.1 Tcfe
- Drill-bit finding cost of $0.22 per mcfe, including performance revisions
- Future development costs for proved undeveloped reserves estimated to be $0.40 per mcfe

Financial Discussion

Except for generally accepted accounting principles ("GAAP") reported amounts, specific expense categories exclude non-cash impairments, unrealized mark-to-market adjustment 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, processing and compression, production and ad valorem taxes, 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 2018

GAAP revenues for 2018 totaled $3.3 billion (26% increase compared to 2017), GAAP net cash provided from operating activities including changes in working capital was $991 million, compared to $816 million in 2017. GAAP net income was a loss of $1.75 billion ($7.10 per diluted share) versus earnings of $333 million ($1.34 per diluted share) in 2017. Full year 2018 results include a $1.6 billion impairment of goodwill associated with the 2016 MRD merger, and a $515 million impairment of unproved properties compared to $270 million in 2017, reflecting a shift in capital allocation related to North Louisiana properties. Full year 2018 results also included a loss of $11 million from asset sales compared to a gain of $24 million in 2017, $51 million in derivative losses due to increases in future commodity prices compared to a $213 million gain in the prior year and a $19 million mark-to-market gain related to the deferred compensation plan compared to a $51 million gain in the prior year.

Non-GAAP revenues for 2018 totaled $3.2 billion, an increase of 33% compared to 2017 and cash flow from operations before changes in working capital, a non-GAAP measure, was $1.05 billion, compared to $916 million in 2017. Adjusted net income comparable to analysts' estimates, a non-GAAP measure, was $279 million ($1.13 per diluted share), compared to $143 million ($0.58 per diluted share) in 2017.

The following table details Range's average production and realized pricing for full year 2018:

Net Production			
Natural Gas (Mmcf/d)	**Oil (Bbl/d)**	**NGLs (Bbl/d)**	**Natural Gas Equivalent (Mmcfe/d)**
1,502	11,585	105,001	2,201

	Realized Pricing			
	Natural Gas ($/Mcf)	**Oil ($/Bbl)**	**NGLs ($/Bbl)**	**Natural Gas Equivalent ($/Mcfe)**
Average NYMEX price	$3.07	$65.49		
Differential, including basis hedging	(0.05)	(4.97)		
Realized prices before NYMEX hedges	3.02	60.52	$24.30	$3.55
Settled NYMEX hedges	(0.04)	(8.92)	(1.69)	(0.16)
Average realized prices after hedges	**$2.98**	**$51.60**	**$22.61**	**$3.39**

Full year 2018 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates) averaged $3.39 per mcfe. Additional detail on commodity price realizations can be found in the Supplemental Tables provided on the Company's website.

- The 2018 average natural gas price, including the impact of basis hedging, was $3.02 per mcf, or a ($0.05) per mcf differential to NYMEX, which was significantly better than the ($0.32) differential in the prior year. The improvement in natural gas differentials compared to last year is a result of increased pipeline connectivity and compressed basis across the Appalachian and Midwest regions.

- Pre-hedge NGL realizations were $24.30 per barrel, or 37% of West Texas Intermediate ("WTI") in 2018. Hedging decreased NGL prices by $1.69 per barrel in 2018 compared to a decrease of $2.04 per barrel in the prior year.

- Crude oil and condensate price realizations, before realized hedges, averaged $60.52 per barrel, or $4.97 below WTI, compared to $4.77 below WTI in the prior year. Hedging decreased price by $8.92 per barrel in 2018, compared to hedge gains of $3.19 per barrel in the prior year.

2018 Unit Costs

The following table details Range's unit costs per mcfe(a):

Expenses	Full Year 2018 (per mcfe)	Full Year 2017 (per mcfe)	Increase (Decrease)
Direct operating	$ 0.17	$ 0.18	(6%)
Transportation, gathering, processing and compression	1.39(b)	1.04	34%
Production and ad valorem taxes	0.06	0.06	-
General and administrative(a)	0.19	0.21	(10%)
Interest expense	0.26	0.26	-
Total cash unit costs(c)	2.07	1.74	19%
Depletion, depreciation and amortization (DD&A)	0.79	0.85	(7%)
Total unit costs plus DD&A(c)	**$ 2.86**	**$ 2.59**	**10%**

(a) Excludes stock-based compensation, legal settlements and amortization of deferred financing costs.
(b) 2018 transportation, gathering, processing and compression expense reflects the change in accounting method made at the beginning of the year. As a result of adopting the new accounting standard, expenses increased by approximately $0.22 per mcfe in 2018. There was an equal increase to NGL revenue, resulting in zero net impact to cash flow as a result of the change in accounting method.
(c) May not add due to rounding.

Fourth Quarter 2018

The following table details Range's average production and realized pricing for fourth quarter 2018:

Net Production			
Natural Gas (Mmcf/d)	Oil (Bbl/d)	NGLs (Bbl/d)	Natural Gas Equivalent (Mmcfe/d)
1,482	9,932	101,263	2,149

	Realized Pricing			
	Natural Gas ($/Mcf)	Oil ($/Bbl)	NGLs ($/Bbl)	Natural Gas Equivalent ($/Mcfe)
Average NYMEX price	$3.61	$60.79		
Differential, including basis hedging	(0.08)	(6.28)		
Realized prices before NYMEX hedges	3.53	54.51	$24.21	$3.83
Settled NYMEX hedges	(0.63)	(4.82)	(0.12)	(0.46)
Average realized prices after hedges	**$2.90**	**$49.69**	**$24.09**	**$3.37**

Fourth quarter 2018 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates) averaged $3.37 per mcfe. Additional detail on commodity price realizations can be found in the Supplemental Tables provided on the Company's website.

- The average natural gas price, including the impact of basis hedging, was $3.53 per mcf, or an ($0.08) per mcf differential to NYMEX, which was significantly better than the ($0.35) differential during the prior-year quarter. The improvement in natural gas differentials compared to last year is a result of increased pipeline connectivity and compressed basis across the Appalachian and Midwest regions.

- Pre-hedge NGL realizations were $24.21 per barrel, or 40% of WTI. Hedging decreased NGL prices by $0.12 per barrel compared to a decrease of $4.06 per barrel in the prior-year quarter.

- Crude oil and condensate price realizations, before realized hedges, averaged $54.51 per barrel, or $6.28 below WTI, compared to $4.63 below WTI in the prior-year quarter. Hedging decreased price by $4.82 per barrel compared to hedge gains of $0.27 per barrel in the prior-year quarter.

Fourth Quarter Unit Costs

The following table details Range's unit costs per mcfe(a):

Expenses	4Q 2018 (per mcfe)	4Q 2017 (per mcfe)	Increase (Decrease)
Direct operating	$ 0.18	$ 0.19	(5%)
Transportation, gathering, processing and compression	1.51(b)	1.00	51%
Production and ad valorem taxes	0.08	0.06	33%
General and administrative(a)	0.16	0.21	(24%)
Interest expense	0.25	0.25	-
Total cash unit costs(c)	2.18	1.70	28%
Depletion, depreciation and amortization (DD&A)	0.75	0.82	(9%)
Total unit costs plus DD&A(c)	$ 2.93	$ 2.52	**16%**

(a) Excludes stock-based compensation, legal settlements and amortization of deferred financing costs.
(b) Fourth quarter 2018 transportation, gathering, processing and compression expense reflects the change in accounting method made earlier this year. As a result of adopting the new accounting standard, expenses increased by approximately $0.23 per mcfe in fourth quarter 2018. There was an equal increase to NGL revenue, resulting in zero net impact to cash flow as a result of the change in accounting method.
(c) May not add due to rounding.

2018 Asset Sale

As previously announced, during fourth quarter 2018, Range sold a proportionately reduced 1% overriding royalty in its Washington County, Pennsylvania leases for gross proceeds of $300 million.

Range's Washington County properties encompass approximately 300,000 net surface acres. The overriding royalty applies to existing and future Marcellus, Utica and Upper Devonian development on the subject leases, while excluding shallower and deeper formations. Post-close, Range maintains a net revenue interest of approximately 82% on the subject Washington County acreage. The net proceeds were used to reduce bank debt.

Operational Discussion

Range previously updated its investor presentation with economic calculations. Please see www.rangeresources.com under the Investors tab, "Company Presentations" area, for the presentation entitled, "Company Presentation – February 25, 2019."

The table below summarizes 2018 activity and estimates for 2019 regarding the number of wells to sales for each area.

	Planned Wells TIL in 2019	Wells TIL in 2018
SW PA Super-Rich	14	14
SW PA Wet	41	38
SW PA Dry	33	34
Total Appalachia	88	86
Total N. LA.	8	12
Total	96	98

Appalachia Division

Production for the fourth quarter of 2018 averaged approximately 1,893 net Mmcfe per day from the Appalachia division, a 5% increase over the prior year. The northeast area of the division averaged 113 net Mmcf per day during the quarter. The southwest area of the division averaged 1,780 net Mmcfe per day during the quarter, a 7% increase over the prior year. As previously announced, in December, an operational issue at the Houston facility required the extended curtailment of both the Harmon Creek and Houston processing complexes. As a result of MarkWest's operational downtime, Range lost approximately 10 Bcfe of production during the quarter. Both processing complexes were returned to service in early January.

Range brought on line 16 wells in southwest Appalachia during the fourth quarter, one in the super-rich area, and 15 in the wet area. During the year, Range turned to sales a total of 86 Marcellus wells with an average lateral length of 9,388 feet. The Company expects to run an average of three rigs in the Marcellus during 2019, and turn to sales 88 wells with an expected average lateral length of 10,800 feet.

North Louisiana

Production for the division in the fourth quarter of 2018 averaged approximately 256 net Mmcfe per day. Range expects to turn to sales eight wells in North Louisiana in 2019.

Marketing and Transportation

Fourth quarter 2018 marked the first full quarter where Range had access to all of its contracted natural gas transportation, as Energy Transfer's Rover project provided additional outlets to the Midwest and Gulf Coast in September. The fourth quarter of 2018 natural gas differential of $0.08 under NYMEX is the best fourth quarter differential Range has seen since 2012, due in large part to the addition of transportation out of Appalachia. Going forward, Range expects to keep its natural gas transportation full and sell incremental gas production into local markets which have improved due to the recently added takeaway infrastructure.

Range has capacity on the Mariner East 1 pipeline for a combined 40,000 barrels per day of ethane and propane. As the only producer with propane capacity on Mariner East 1, Range has been able to capture premiums to the Mont Belvieu index price by exporting the majority of its propane to international markets since early 2016. In addition, the Company sent the majority of its normal butane and remaining propane volumes during the summer to Marcus Hook for export via local rail. As the Company continues to develop its liquids acreage, additional outlets for NGL production are beneficial in providing stability to NGL price, especially during the summer when in-basin demand is low. Range has taken capacity on Mariner East 2 for a combined 20,000 barrels per day of propane and butane, starting in April 2020, which gives the Company additional flexibility in marketing NGL production while participating in the expected local market improvements. Importantly, Range expects to fill the incremental capacity with existing propane and butane volumes, leaving flexibility to sell incremental NGLs in-basin.

In January 2019, Range lost access to its capacity on Sunoco's Mariner East 1 pipeline following the appearance of a subsidence along the pipeline route. As a result of the outage, Range is utilizing available capacity on the recently commissioned Mariner East 2 pipeline to continue moving its propane to the Marcus Hook terminal. For ethane, Range has multiple options for marketing its production, including the ability to sell ethane as natural gas. While not materially altering corporate cash flows, the delayed restart of MarkWest plants and the Mariner East outage have reduced production volumes, and as a result, Range's first quarter guidance of 2,225 Mmcfe per day reflects the estimated production impact.

Guidance – 2019

Production per day Guidance

Production for the full-year 2019 is expected to average approximately 2,325 to 2,345 Mmcfe per day, or 6% year-over-year growth at the midpoint.

First quarter 2019 production is expected to average approximately 2,225 Mmcfe per day.

1Q 2019 Expense Guidance

Direct operating expense:	$0.17 - $0.19 per mcfe
Transportation, gathering, processing and compression expense:	$1.48 - $1.52 per mcfe
Production tax expense:	$0.05 - $0.06 per mcfe
Exploration expense:	$6.0 - $9.0 million
Unproved property impairment expense:	$7.0 - $10.0 million
G&A expense:	$0.20 - $0.22 per mcfe
Interest expense:	$0.24 - $0.26 per mcfe
DD&A expense:	$0.74 - $0.78 per mcfe
Net brokered gas marketing (gain) expense:	~ ($3.0 million)

1Q 2019 Natural Gas Price Differential Guidance NYMEX plus $0.01

Full Year 2019 Price Guidance

Based on current market pricing indications, Range expects to average the following pre-hedge differentials for its production in 2019.

Natural Gas:	NYMEX minus $0.15 to $0.20
Natural Gas Liquids (including ethane):	36% - 38% of WTI
Oil/Condensate:	WTI minus $6.00 to $8.00

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. At year-end 2018, Range had over 75% of its expected 2019 natural gas production hedged at a weighted average floor price of $2.86 per mmbtu. Similarly, Range had hedged approximately 70% of its 2019 projected crude oil production at an average floor price of $56.23. 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 to limit volatility between NYMEX and regional prices. The fair value of the basis hedges as of December 31, 2018 was a gain of $4.8 million, compared to a loss of $7.8 million at December 31, 2017.

Conference Call Information

A conference call to review the financial results is scheduled on Tuesday, February 26 at 9:00 a.m. ET. To participate in the call, please dial 866-900-7525 and provide conference code 6972159 about 10 minutes prior to the scheduled start time.

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 26.

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 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, processing 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, processing 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, processing and compression expense, which were historically reported as natural gas, NGLs and oil sales. This information is intended 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 Annual Report on 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.

Finding and development cost per unit is a non-GAAP metric used in the exploration and production industry by companies, investors and analysts. 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, performance and price revisions. These calculations do not include the future development costs required for the development of proved undeveloped reserves. This reserves metric may not be comparable to similarly titled measurements used by other companies. The U.S. Securities and Exchange Commission (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.

We believe that the presentation of PV10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV10 is based on prices and discount factors that are consistent for all companies. Because of this, PV10 can be used within the industry and by creditors and security analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

RANGE RESOURCES CORPORATION (NYSE: RRC) is a leading U.S. independent oil and natural gas producer with operations focused in stacked-pay projects in the Appalachian Basin and North Louisiana. 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.

Included within are certain "forward-looking statements" within the meaning of the federal securities laws, including the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 that are not limited to historical facts, but reflect Range's current beliefs, expectations or intentions regarding future events. Words such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "outlook", *“estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” and similar expressions are intended to identify such forward-looking statements.*

All statements, except for statements of historical fact, made within regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future well costs, expected asset sales, well productivity, future liquidity and financial resilience, anticipated exports and related financial impact, NGL market supply and demand, improving commodity fundamentals and pricing, future capital efficiencies, future shareholder value, emerging plays, capital spending, anticipated drilling and completion activity, acreage prospectivity, expected pipeline utilization and future guidance information are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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. Further information on risks and uncertainties is available in Range's filings with the Securities and Exchange Commission (SEC), including its most recent Annual Report on Form 10-K. Unless required by law, Range undertakes no obligation to publicly update or revise any forward-looking statements to reflect circumstances or events after the date they are made.

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 its 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.

SOURCE: Range Resources Corporation

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

	Three Months Ended December 31,			Twelve Months Ended Dece	
	2018	2017	%	2018	2017
Revenues and other income:					
Natural gas, NGLs and oil sales (a)	$ 756,627	$ 603,159		$ 2,851,077	$ 2,176,28
Derivative fair value (loss)/income	100,698	25,024		(51,192)	213,35
Brokered natural gas, marketing and other (b)	215,270	50,732		482,044	219,47
ARO settlement gain (loss) (b)	(59)	(17)		(71)	4
Other (b)	101	134		787	1,87
Total revenues and other income	1,072,637	679,032	58%	3,282,645	2,611,03
Costs and expenses:					
Direct operating	34,953	37,424		137,422	132,19
Direct operating – non-cash stock-based compensation (c)	442	497		2,109	2,06
Transportation, gathering, processing and compression	298,716	200,300		1,117,816	761,18
Production and ad valorem taxes	16,656	11,757		46,149	42,88
Brokered natural gas and marketing	221,175	50,734		494,595	218,87
Brokered natural gas and marketing – non-cash stock-based compensation (c)	451	397		1,452	1,43
Exploration	10,206	6,747		32,196	50,92
Exploration – non-cash stock-based compensation (c)	394	1,146		1,921	2,74
Abandonment and impairment of unproved properties	441,750	217,544		514,994	269,72
General and administrative	30,785	41,167		152,040	150,78
General and administrative – non-cash stock-based compensation (c)	5,474	39,717		43,806	74,87
General and administrative – lawsuit settlements	13,581	(831)		14,966	6,19
General and administrative – bad debt expense	250	500		(1,000)	1,55
Termination costs	—	(278)		(373)	2,10
Termination costs – non-cash stock-based compensation (c)	—	(1)		—	1,66
Deferred compensation plan (d)	(18,072)	(14,077)		(18,631)	(50,91
Interest expense	50,237	49,629		205,970	188,45
Interest expense – amortization of deferred financing costs (e)	(1,076)	1,844		4,239	7,22
Depletion, depreciation and amortization	147,909	162,918		635,467	624,99
Impairment of proved property	—	—		22,614	63,67
Impairment of goodwill	1,641,197	—		1,641,197	–
Gain on sale of assets	10,815	(207)		10,666	(23,71
Total costs and expenses	2,905,843	806,927	260%	5,059,615	2,528,91
(Loss) income before income taxes	(1,833,206)	(127,895)	N.M.	(1,776,970)	82,12
Income tax (benefit) expense:					
Current	—	17		—	1
Deferred	(68,784)	(349,097)		(30,489)	(251,04
	(68,784)	(349,080)		(30,489)	(251,02
Net (loss) income	$ (1,764,422)	$ 221,185	N.M.	$ (1,746,481)	$ 333,14
Net (Loss) Income Per Common Share:					
Basic	$ (7.15)	$ 0.89		$ (7.10)	$ 1.3
Diluted	$ (7.15)	$ 0.89		$ (7.10)	$ 1.3
Weighted average common shares outstanding, as reported:					
Basic	246,631	245,281	1%	246,171	245,09
Diluted	246,631	245,537	0%	246,171	245,45

(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, which 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.
(e) Included in interest expense in the 10-K.

BALANCE SHEETS
(In thousands)

	December 31, 2018 (Audited)	December 31, 2017 (Audited)
Assets		
Current assets	$ 514,232	$ 370,627
Derivative assets	92,795	58,880
Goodwill	—	1,641,197
Natural gas and oil properties, successful efforts method	9,023,185	9,566,737
Transportation and field assets	9,776	14,666
Other	68,166	76,734
	$ 9,708,154	$ 11,728,841
Liabilities and Stockholders' Equity		
Current liabilities	$ 745,182	$ 704,913
Asset retirement obligations	5,485	6,327
Derivative liabilities	4,144	44,233
Bank debt	932,018	1,208,467
Senior notes	2,856,166	2,851,754
Senior subordinated notes	48,677	48,585
Total debt	3,836,861	4,108,806
Deferred tax liability	666,668	693,356
Derivative liabilities	3,462	9,789
Deferred compensation liability	67,542	101,102
Asset retirement obligations and other liabilities	319,379	286,043
Common stock and retained earnings	4,060,480	5,776,203
Other comprehensive loss	(658)	(1,332)
Common stock held in treasury stock	(391)	(599)
Total stockholders' equity	4,059,431	5,774,272
	$ 9,708,154	$ 11,728,841

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 D	
	2018	2017	%	2018	2017
Total revenues and other income, as reported	$ 1,072,637	$ 679,032	58%	$ 3,282,645	$ 2,611,(
Adjustment for certain special items:					
Total change in fair value related to derivatives prior to settlement (gain) loss	(191,948)	(27,969)		(80,330)	(200,2
ARO settlement (gain) loss	59	17		71	(
Total revenues, as adjusted, non-GAAP	$ 880,748	$ 651,080	35%	$ 3,202,386	$ 2,410,7

CASH FLOWS FROM OPERATING ACTIVITIES
(Unaudited in thousands)

	Three Months Ended December 31,		Twelve Months Ended	
	2018	2017	2018	
Net (loss) income	$ (1,764,422)	$ 221,185	$ (1,746,481)	$
Adjustments to reconcile net cash provided from continuing operations:				
Deferred income tax (benefit) expense	(68,784)	(349,097)	(30,489)	
Depletion, depreciation, amortization and impairment	147,909	162,918	658,081	
Impairment of goodwill	1,641,197	—	1,641,197	
Exploration dry hole costs	—	6	4	
Abandonment and impairment of unproved properties	441,750	217,544	514,994	
Derivative fair value (income) loss	(100,698)	(25,024)	51,192	
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	(91,250)	(2,945)	(131,522)	
Allowance for bad debts	250	500	(1,000)	
Amortization of deferred issuance costs, loss on extinguishment of debt, and other	(1,648)	1,261	2,515	
Deferred and stock-based compensation	(11,495)	26,769	29,757	
Loss (gain) on sale of assets and other	10,815	(207)	10,666	
Changes in working capital:				
Accounts receivable	(92,668)	(63,172)	(142,381)	
Inventory and other	960	(1,475)	138	
Accounts payable	2,255	1,197	(4,274)	
Accrued liabilities and other	101,572	26,262	138,293	
Net changes in working capital	12,119	(37,188)	(8,224)	
Net cash provided from operating activities	$ 215,743	$ 215,722	$ 990,690	$

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,		Twelve Months Ended Decemb	
	2018	2017	2018	
Net cash provided from operating activities, as reported	$ 215,743	$ 215,722	$ 990,690	$
Net changes in working capital	(12,119)	37,188	8,224	
Exploration expense	10,206	6,741	32,192	
Lawsuit settlements	13,581	(831)	14,966	
Termination costs	—	(278)	(373)	
Non-cash compensation adjustment	815	1,510	2,695	
Cash flow from operations before changes in working capital – non-GAAP measure	$ 228,226	$ 260,052	$ 1,048,394	$

ADJUSTED WEIGHTED AVERAGE SHARES OUTSTANDING
(Unaudited, in thousands)

	Three Months Ended December 31,		Twelve Months Ended Decemb	
	2018	2017	2018	
Basic:				
Weighted average shares outstanding	249,515	248,140	249,228	
Stock held by deferred compensation plan	(2,884)	(2,859)	(3,057)	
Adjusted basic	246,631	245,281	246,171	
Dilutive:				
Weighted average shares outstanding	249,515	248,140	249,228	
Dilutive stock options under treasury method	(2,884)	(2,603)	(3,057)	
Adjusted dilutive	246,631	245,537	246,171	

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, a non-GAAP measure
(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31,			Twelve Months Ended December	
	2018	2017	%	2018	2017
Natural gas, NGL and oil sales components:					
Natural gas sales	$ 481,252	$ 340,965		$ 1,663,832	$ 1,349,945
NGL sales	225,567	192,232		931,360	604,672
Oil sales	49,808	69,962		255,885	221,650
Total oil and gas sales, as reported	$ 756,627	$ 603,159	25%	$ 2,851,077	$ 2,176,267
Derivative fair value income (loss), as reported:	$ 100,698	$ 25,024		$ (51,192)	$ 213,350
Cash settlements on derivative financial instruments – (gain) loss:					
Natural gas	85,757	(36,412)		29,291	(71,059)
NGLs	1,087	39,733		64,522	73,192
Crude Oil	4,406	(376)		37,709	(15,250)
Total change in fair value related to derivatives prior to settlement, a non-GAAP measure	$ 191,948	$ 27,969		$ 80,330	$ 200,233
Transportation, gathering, processing and compression components:					
Natural gas	$ 180,920	$ 141,902		$ 678,489	$ 526,671
NGLs	117,796	58,398		439,327	234,512
Total transportation, gathering, processing and compression, as reported	$ 298,716	$ 200,300		$ 1,117,816	$ 761,183
Natural gas, NGL and oil sales, including cash-settled derivatives: (c)					
Natural gas sales	$ 395,495	$ 377,377		$ 1,634,541	$ 1,421,004
NGL sales	224,480	152,499		866,838	531,480
Oil sales	45,402	70,338		218,176	236,900
Total	$ 665,377	$ 600,214	11%	$ 2,719,555	$ 2,189,384
Production of oil and gas during the periods (a):					
Natural gas (mcf)	136,315,861	132,864,354	3%	548,085,437	490,253,467
NGL (bbl)	9,316,151	9,755,481	-5%	38,325,251	35,709,254
Oil (bbl)	913,735	1,380,649	-34%	4,228,439	4,787,022
Gas equivalent (mcfe) (b)	197,695,177	199,681,134	-1%	803,407,577	733,231,123
Production of oil and gas – average per day (a):					
Natural gas (mcf)	1,481,694	1,444,178	3%	1,501,604	1,343,160
NGL (bbl)	101,263	106,038	-5%	105,001	97,834
Oil (bbl)	9,932	15,007	-34%	11,585	13,115
Gas equivalent (mcfe) (b)	2,148,861	2,170,447	-1%	2,201,117	2,008,852
Average prices, excluding derivative settlements and before third party transportation costs:					
Natural gas (mcf)	$ 3.53	$ 2.57	38%	$ 3.04	$ 2.75
NGL (bbl)	$ 24.21	$ 19.71	23%	$ 24.30	$ 16.93
Oil (bbl)	$ 54.51	$ 50.67	8%	$ 60.52	$ 46.30
Gas equivalent (mcfe) (b)	$ 3.83	$ 3.02	27%	$ 3.55	$ 2.97
Average prices, including derivative settlements before third party transportation costs: (c)					
Natural gas (mcf)	$ 2.90	$ 2.84	2%	$ 2.98	$ 2.90
NGL (bbl)	$ 24.10	$ 15.63	54%	$ 22.62	$ 14.88
Oil (bbl)	$ 49.69	$ 50.95	-2%	$ 51.60	$ 49.49
Gas equivalent (mcfe) (b)	$ 3.37	$ 3.01	12%	$ 3.39	$ 2.99
Average prices, including derivative settlements and after third party transportation costs: (d)					
Natural gas (mcf)	$ 1.57	$ 1.77	-11%	$ 1.74	$ 1.82
NGL (bbl)	$ 11.45	$ 9.65	19%	$ 11.15	$ 8.32
Oil (bbl)	$ 49.69	$ 50.95	-2%	$ 51.60	$ 49.49
Gas equivalent (mcfe) (b)	$ 1.85	$ 2.00	-7%	$ 1.99	$ 1.95
Transportation, gathering and compression expense per mcfe	$ 1.51	$ 1.00	51%	$ 1.39	$ 1.04

(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, processing and compression costs.

RECONCILIATION OF INCOME BEFORE (LOSS) 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 I	
	2018	2017	%	2018	201
(Loss) income from operations before income taxes, as reported	$ (1,833,206)	$ (127,895)	N.M.	$ (1,776,970)	$ 8
Adjustment for certain special items:					
Loss (gain) on sale of assets	10,815	(207)		10,666	(2
Loss (gain) on ARO settlements	59	17		71	
Change in fair value related to derivatives prior to settlement	(191,948)	(27,969)		(80,330)	(20
Impairment of goodwill	1,641,197	—		1,641,197	
Abandonment and impairment of unproved properties	441,750	217,544		514,994	26
Impairment of proved property	—	—		22,614	6
Lawsuit settlements	13,581	(831)		14,966	
Termination costs	—	(278)		(373)	
Termination costs – non-cash stock-based compensation	—	(1)		—	
Brokered natural gas and marketing – non-cash stock-based compensation	451	397		1,452	
Direct operating – non-cash stock-based compensation	442	497		2,109	
Exploration expenses – non-cash stock-based compensation	394	1,146		1,921	
General & administrative – non-cash stock-based compensation	5,474	39,717		43,806	7
Deferred compensation plan – non-cash adjustment	(18,072)	(14,077)		(18,631)	(5
Income before income taxes, as adjusted	70,937	88,060	-19%	377,492	23
Income tax expense, as adjusted					
Current	—	17		—	
Deferred (a)	18,444	33,446		98,061	8
Net income excluding certain items, a non-GAAP measure	$ 52,493	$ 54,597	-4%	$ 279,431	$ 14
Non-GAAP income per common share					
Basic	$ 0.21	$ 0.22	-5%	$ 1.14	$
Diluted	$ 0.21	$ 0.22	-5%	$ 1.13	$
Non-GAAP diluted shares outstanding, if dilutive	247,719	245,537		247,220	24

(a) Deferred taxes for 2018 are estimated to be approximately 26% and 38% for 2017.

RECONCILIATION OF NET (LOSS) INCOME, EXCLUDING CERTAIN ITEMS AND ADJUSTED EARNINGS PER SHARE, non-GAAP measures
(In thousands, except per share data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2018	2017	2018	2017
Net (loss) income, as reported	$ (1,764,422)	$ 221,185	$ (1,746,481)	$ 333,146
Adjustment for certain special items:				
(Gain) loss on sale of assets	10,815	(207)	10,666	(23,716)
Loss (gain) on ARO settlements	59	17	71	(47)
Change in fair value related to derivatives prior to settlement	(191,948)	(27,969)	(80,330)	(200,233)
Impairment of goodwill	1,641,197	—	1,641,197	—
Impairment of proved property	—	—	22,614	63,679
Abandonment and impairment of unproved properties	441,750	217,544	514,994	269,725
Lawsuit settlements	13,581	(831)	14,966	6,197
Termination costs	—	(278)	(373)	2,106
Non-cash stock-based compensation	6,761	41,756	49,288	82,776
Deferred compensation plan	(18,072)	(14,077)	(18,631)	(50,915)
Tax impact	(87,228)	(382,543)	(128,550)	(339,781)
Net income excluding certain items, a non-GAAP measure	$ 52,493	$ 54,597	$ 279,431	$ 142,937
Net (loss) income per diluted share, as reported	$ (7.15)	$ 0.89	$ (7.10)	$ 1.34
Adjustment for certain special items per diluted share:				
(Gain) loss on sale of assets	0.04	(0.00)	0.04	(0.10)
Loss (gain) on ARO settlements	0.00	0.00	0.00	(0.00)
Change in fair value related to derivatives prior to settlement	(0.78)	(0.11)	(0.33)	(0.82)
Impairment of goodwill	6.65	—	6.67	—
Impairment of proved property	—	—	0.09	0.26
Abandonment and impairment of unproved properties	1.79	0.89	2.09	1.10
Lawsuit settlements	0.06	(0.00)	0.06	0.03
Termination costs	—	(0.00)	(0.00)	0.01
Non-cash stock-based compensation	0.03	0.17	0.20	0.34
Deferred compensation plan	(0.07)	(0.06)	(0.08)	(0.21)
Adjustment for rounding differences	(0.01)	—	0.01	0.01
Tax impact	(0.35)	(1.56)	(0.52)	(1.38)
Net income per diluted share, excluding certain items, a non-GAAP measure	$ 0.21	$ 0.22	$ 1.13	$ 0.58
Adjusted earnings per share, a non-GAAP measure:				
Basic	$ 0.21	$ 0.22	$ 1.14	$ 0.58
Diluted	$ 0.21	$ 0.22	$ 1.13	$ 0.58

RECONCILIATION OF CASH MARGIN PER MCFE, a non-GAAP measure
(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31, 2018	Three Months Ended December 31, 2017	Twelve Months Ended December 31, 2018	Twelve Months Ended December 31, 2017
Revenues				
Natural gas, NGL and oil sales, as reported	$ 756,627	$ 603,159	$ 2,851,077	$ 2,176,287
Derivative fair value income (loss), as reported	100,698	25,024	(51,192)	213,350
Less non-cash fair value (gain) loss	(191,948)	(27,969)	(80,330)	(200,233)
Brokered natural gas and marketing and other, as reported	215,312	50,849	482,760	221,393
Less ARO settlement and other (gains) losses	(42)	(117)	(716)	(1,919)
Cash revenue applicable to production	880,647	650,946	3,201,599	2,408,878
Expenses				
Direct operating, as reported	35,395	37,921	139,531	134,252
Less direct operating stock-based compensation	(442)	(497)	(2,109)	(2,060)
Transportation, gathering and compression, as reported	298,716	200,300	1,117,816	761,183
Production and ad valorem taxes, as reported	16,656	11,757	46,149	42,882
Brokered natural gas and marketing, as reported	221,626	51,131	496,047	220,311
Less brokered natural gas and marketing stock-based compensation	(451)	(397)	(1,452)	(1,437)
General and administrative, as reported	50,090	80,553	209,812	233,406
Less G&A stock-based compensation	(5,474)	(39,717)	(43,806)	(74,873)
Less lawsuit settlements	(13,581)	831	(14,966)	(6,197)
Interest expense, as reported	49,161	51,473	210,209	195,679
Less amortization of deferred financing costs	1,076	(1,844)	(4,239)	(7,229)
Cash expenses	652,772	391,511	2,152,992	1,495,917
Cash margin, a non-GAAP measure	$ 227,875	$ 259,435	$ 1,048,607	$ 912,961
Mmcfe produced during period	197,695	199,681	803,408	733,231
Cash margin per mcfe	$ 1.15	$ 1.30	$ 1.31	$ 1.25

RECONCILIATION OF (LOSS) INCOME BEFORE INCOME TAXES TO CASH MARGIN
(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31, 2018	Three Months Ended December 31, 2017	Twelve Months Ended December 31, 2018	Twelve Months Ended December 31, 2017
(Loss) income before income taxes, as reported	$ (1,833,206)	$ (127,895)	$ (1,776,970)	$ 82,120
Adjustments to reconcile income (loss) before income taxes to cash margin:				
ARO settlements and other (gains) losses	(42)	(117)	(716)	(1,919)
Derivative fair value (income) loss	(100,698)	(25,024)	51,192	(213,350)
Net cash receipts on derivative settlements	(91,250)	(2,945)	(131,522)	13,117
Exploration expense	10,206	6,747	32,196	50,920
Lawsuit settlements	13,581	(831)	14,966	6,197
Termination costs	—	(278)	(373)	2,106
Deferred compensation plan	(18,072)	(14,077)	(18,631)	(50,915)
Stock-based compensation (direct operating, brokered natural gas and marketing, general and administrative and termination costs)	6,761	41,756	49,288	82,776
Interest – amortization of deferred financing costs	(1,076)	1,844	4,239	7,229
Depletion, depreciation and amortization	147,909	162,918	635,467	624,992
(Gain) loss on sale of assets	10,815	(207)	10,666	(23,716)
Impairment of goodwill	1,641,197	—	1,641,197	—
Impairment of proved property and other assets	—	—	22,614	63,679
Abandonment and impairment of unproved properties	441,750	217,544	514,994	269,725
Cash margin, a non-GAAP measure	$ 227,875	$ 259,435	$ 1,048,607	$ 912,961

HEDGING POSITION AS OF DECEMBER 31, 2018 – (Unaudited)

	Daily Volume	Hedge Price
Gas [1]		
1Q 2019 Swaps	1,385,000 Mmbtu	$3.05
2Q 2019 Swaps	1,455,000 Mmbtu	$2.80
3Q 2019 Swaps	1,455,000 Mmbtu	$2.80
4Q 2019 Swaps	1,428,478 Mmbtu	$2.81
2020 Swaps	80,000 Mmbtu	$2.77
Oil		
2019 Collar	1,000 bbls	$63 x 73
1H 2019 Swaps	7,000 bbls	$55.08
2H 2019 Swaps	7,000 bbls	$55.45
2020 Swaps	1,562 bbls	$61.05
C3 Propane		
1Q 2019 Collars	7,000 bbls	$0.927 x $1.029 /gallon
2Q 2019 Collars	1,000 bbls	$0.90 x $0.96 /gallon
1Q 2019 Swaps	8,500 bbls	$0.963/gallon
2Q 2019 Swaps	8,500 bbls	$0.878/gallon
C4 Normal Butane		
1Q 2019 Swaps	2,500 bbls	$1.221/gallon
C5 Natural Gasoline		
1Q 2019 Swaps	3,750 bbls	$1.438/gallon
2Q 2019 Swaps	3,000 bbls	$1.401/gallon
3Q 2019 Swaps	1,500 bbls	$1.472/gallon
4Q 2019 Swaps	1,500 bbls	$1.475/gallon

(1) Range also sold call swaptions of 230,000 Mmbtu/d for calendar 2020 at an average strike price of $2.80 per Mmbtu

SEE WEBSITE FOR OTHER SUPPLEMENTAL INFORMATION FOR THE PERIODS AND ADDITIONAL HEDGING DETAILS