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 22, 2017 (February 22, 2017)

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 22, 2017 Range Resources Corporation issued a press release announcing its 2016 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 22, 2017

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 22, 2017

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press Release dated February 22, 2017

RANGE REPORTS 2016 EARNINGS, ANNOUNCES 2017 CAPITAL PLANS

FORT WORTH, TEXAS, FEBRUARY 22, 2017…RANGE RESOURCES CORPORATION (NYSE: RRC) today announced its 2016 financial results and 2017 capital spending plan.

Highlights –

- Record average daily production of 1.854 Bcfe during the fourth quarter
- 2017 capital budget set at $1.15 billion, projected to provide 33-35% year-over-year growth in 2017 and approximately 20% organic growth in 2018
- North Louisiana well costs reduced to $7.7 million per well from $8.7 million previously
- Fourth quarter 2016 unhedged cash margins improved by over four times to $0.97 per mcfe, compared to $0.22 per mcfe in fourth quarter 2015
- Reserve replacement of 292% at $0.34 per mcfe drill-bit development cost for 2016

Commenting, Jeff Ventura, the Company's CEO said, "2016 was a significant year for Range, as we completed the acquisition of Memorial Resource Development in September, providing Range operational and geographic diversity with wells that rival our prolific Marcellus wells. In addition, we are beginning to see the advantages of a diversified marketing portfolio, as prices are expected to improve for all products in 2017, driving higher margins and a peer-leading recycle ratio. Higher expected margins and cash flow provide us the opportunity to increase our capital budget to $1.15 billion in 2017, after two consecutive years of declining capital spending. This increased activity in 2017 results in solid growth this year, but also positions us well for 2018 and beyond. With thousands of future locations in our core inventory and talented operational, technical and marketing teams, Range is well-positioned to drive shareholder value for years to come."

Capital Spending Plans

Range has set its 2017 capital spending budget at $1.15 billion. Approximately two-thirds of the capital budget will be allocated to the Marcellus and one-third to North Louisiana. The budget includes projected service cost increases in 2017, which are expected to be minimal in the Company's areas of operation. In the Marcellus, approximately 80% of activity will be directed towards liquids-rich drilling, which has a number of advantages. Range's liquids-rich acreage has an extensive inventory of existing pads that reduce capital costs and gathering expense. The acreage is also in close proximity to capacity for both existing and expected NGL and natural gas takeaway projects, improving netback pricing. Lastly, recent improvements in NGL pricing has bolstered expected drilling returns. Despite shifting capital towards the liquids-rich area, the Company still expects production of approximately 2.07 Bcfe per day in 2017, which equates to absolute growth of 33% to 35% year-over-year. Capital spending in 2017 will also contribute towards production growth of approximately 20% in 2018, expected to be at or near cash flow, assuming a natural gas price of $3.25 per mcf and an oil price of $60.00 per barrel.

The 2017 capital budget includes approximately $1.07 billion for drilling and recompletions (93% of the total), $44 million for leasehold, $22 million for seismic, and $18 million for pipelines, facilities and other. The budget includes 118 wells expected to be brought on line during the year in the Marcellus and 56 wells in North Louisiana. In the Marcellus, approximately one third of the wells are planned to be drilled from existing pads in 2017.

Fourth quarter 2016 drilling expenditures of $195 million funded the drilling of 22 (18.9 net) wells. Drilling expenditures for the year totaled $535 million, and Range drilled 108 (101.9 net) wells during the year. A 100% success rate was achieved. In addition, during 2016, $33 million was spent on acreage purchases, $4 million on gas gathering systems and $30 million on exploration expense. The capital expenditure amounts include North Louisiana expenditures incurred since closing of the merger on September 16, 2016. Drill-bit only finding cost averaged $0.34 per mcfe, including pricing and performance revisions with a reserve replacement ratio of 292%.

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.

Fourth Quarter 2016

GAAP revenues for the fourth quarter of 2016 totaled $254 million (38% decrease compared to fourth quarter 2015), GAAP net cash provided from operating activities including changes in working capital was $185 million (a 5% increase as compared to fourth quarter 2015) and GAAP earnings were a loss of $161 million ($0.66 per diluted share) versus a loss of $322 million ($1.93 per diluted share) in the prior-year quarter. Fourth quarter 2016 results included a $470,000 gain on sale of assets, while 2015 included a loss of $409 million. Fourth quarter 2016 also included $250 million in derivative losses due to increased commodity prices, compared to a $126 million gain in 2015. An $88 million impairment of proved property was also recorded in 2015.

Non-GAAP revenues for fourth quarter 2016 totaled $590 million (30% increase compared to fourth quarter 2015) and cash flow from operations before changes in working capital, a non-GAAP measure, reached $254 million, compared to $204 million in 2015. Adjusted net income comparable to analysts' estimates, a non-GAAP measure, was $56 million ($0.23 per diluted share) compared to $42 million ($0.25 per diluted share) for the fourth quarter 2015. The Company's total unit costs were lower than the previous year quarter, with decreases in all categories, except general & administrative and transportation, gathering, processing & compression. General & administrative expenses were higher due to non-recurring land administrative expenses while increased transportation expenses are offset by higher realized prices, as products are moved to more favorable markets.

Expenses	4Q 2016 (per mcfe)	4Q 2015 (per mcfe)	Increase (Decrease)
Direct operating	$ 0.17	$ 0.22	(23%)
Transportation, gathering, processing and compression	0.96	0.85	13%
Production and ad valorem taxes	0.04	0.06	(33%)
General and administrative	0.26	0.22	18%
Interest expense	0.27	0.31	(13%)
Total cash unit costs	1.70	1.66	2%
Depletion, depreciation and amortization	0.88	0.97	(9%)
Total unit costs	$ 2.58	$ 2.63	(2%)

Fourth quarter 2016 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates) averaged $3.20 per mcfe, a 1% 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 fourth quarter 2016 were: natural gas – 1,244 Mmcf per day ($2.93 per mcf), NGLs – 89,628 barrels per day ($17.20 per barrel) and crude oil and condensate – 12,005 barrels per day ($61.30 per barrel).

- The average Company natural gas price differential including the impact of basis hedges for the fourth quarter was ($0.37) per mcf, which is unchanged from the prior year. The fourth quarter average natural gas price, before all hedging settlements, increased to $2.62 per mcf as compared to $1.90 per mcf in the prior year. NYMEX natural gas financial hedges increased realizations $0.31 per mcf in the fourth quarter of 2016.

- Pre-hedge NGL realizations improved to 29% of West Texas Intermediate ("WTI") in fourth quarter 2016, compared to 22% of WTI in the previous year. Total NGL pricing per barrel including ethane and processing expenses after realized cash-settled hedging improved to $17.20 for the fourth quarter compared to $11.23 per barrel in the prior year. Hedging increased NGL prices by $2.70 per barrel in the fourth quarter compared to $2.12 per barrel in the prior year.

- Crude oil and condensate price realizations, before realized hedges, for the fourth quarter averaged $44.61 per barrel, or $4.66 below WTI, compared to $13.52 below WTI in the prior year. Hedging added $16.69 per barrel compared to hedge gains of $50.92 in the prior year.

Full Year 2016

GAAP revenues for 2016 totaled $1.1 billion (31% decrease compared to 2015), GAAP net cash provided from operating activities including changes in working capital was $387 million, compared to $691 million in 2015, and GAAP earnings were a loss of $521 million ($2.75 per diluted share) versus a loss of $714 million ($4.29 per diluted share) in 2015. Full year 2016 results included a loss of $7 million from asset sales compared to a loss of $407 million in 2015, $261 million in derivative losses due to increases in future commodity prices compared to a $416 million gain in the prior year and a $43 million impairment of proved property compared to a $590 million impairment of a non-Marcellus property in the prior year.

Non-GAAP revenues for 2016 totaled $1.7 billion, unchanged from 2015 and cash flow from operations before changes in working capital, a non-GAAP measure, was $569 million, compared to $740 million in 2015. Adjusted net income comparable to analysts' estimates, a non-GAAP measure, was $4.9 million ($0.03 per diluted share), compared to $80 million ($0.48 per diluted share) in 2015. The Company's cost structure continued to improve as total unit costs decreased by $0.17 per mcfe, or 6%, compared to the prior year, as shown below.

Expenses	**Full Year 2016 (per mcfe)**	**Full Year 2015 (per mcfe)**	**Increase (Decrease)**
Direct operating	$ 0.17	$ 0.26	(35%)
Transportation, gathering, processing and compression	1.00	0.78	28%
Production and ad valorem taxes	0.05	0.07	(29%)
General and administrative	0.23	0.27	(15%)
Interest expense	0.30	0.33	(9%)
Total cash unit costs	1.75	1.71	2%
Depletion, depreciation and amortization	0.93	1.14	(18%)
Total unit costs	$ 2.68	$ 2.85	(6%)

The Company announced its full year 2016 natural gas, NGLs and oil price realizations (including the impact of cash-settled hedges and derivative settlements which correspond to analysts' estimates), which averaged $2.74 per mcfe, a 14% 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 2016 were: natural gas – 1,027 Mmcf per day ($2.68 per mcf), NGLs – 76,026 barrels per day ($13.16 per barrel) and crude oil and condensate – 9,861 barrels per day ($47.82 per barrel).

- The 2016 average Company natural gas price differential including the impact of basis hedging improved to ($0.45) per mcf compared to ($0.52) per mcf in the prior year. The 2016 average natural gas price, before all hedging settlements, decreased to $2.06 per mcf as compared to $2.13 per mcf in the prior year. NYMEX natural gas financial hedges increased realizations $0.61 per mcf for 2016.

- Pre-hedge NGL realizations improved to 26% of WTI in 2016, compared to 18% of WTI in 2015. Total NGL pricing per barrel including ethane and processing expenses after realized cash-settled hedging was $13.15 per barrel compared to $10.73 in the prior year. Hedging increased NGL prices by $1.71 per barrel in 2016 compared to $2.06 in the prior year.

- Crude oil and condensate price realizations, before hedges, for the year averaged $34.60 per barrel, or $9.09 below WTI, compared to $14.93 below WTI in the prior year. Hedging added $13.22 per barrel in 2016, compared to hedge gains of $37.00 per barrel in the prior year.

Operational Discussion

Range has updated its investor presentation with new economic calculations and type curves for the Marcellus and North Louisiana. Please see www.rangeresources.com under the Investors tab, "Company Presentations" area, for the presentation entitled, "Company Presentation – February 22, 2017"

The table below summarizes the 2016 activity and estimates for 2017 regarding the number of wells to sales, average lateral lengths, well costs, EURs by area and Range's current net acreage for each area. Consistent with the prior year, updated type curves reflect expected flow restrictions that result from infrastructure and facility design constraints. As a result, early production from prolific wells is often constrained, resulting in flatter decline curves, and is reflected in the type curves. As seen in the presentation slides, Marcellus wells turned in line ("TIL") over the past three years continue to perform in line with type curve expectations. These results demonstrate the quality of acreage as the Company continues development across its core position in southwest Pennsylvania. Similar data is expected to be provided for North Louisiana drilling results going forward.

	Wells TIL in 2016	Average 2016 Lateral Length	Planned Wells TIL in 2017	Expected Average 2017 Lateral Length
SW PA Super-Rich	14	5,100 ft.	35	8,500 ft.
SW PA Wet	30	6,400 ft.	56	8,300 ft.
SW PA Dry	46	6,900 ft.	25	8,850 ft.
NE PA Dry	19	5,700 ft.	2	6,400 ft.
Total Marcellus	109		118	
Upper Red	—		34	7,500 ft.
Lower Red	—		13	7,500 ft.
Pink	—		6	
Expansion area	3		3	
Total N. LA	3		56	
Total	112		174	

	Expected 2017 Well Costs	Projected EURs for 2017 Wells	Net Acreage by Area (Marcellus only)
SW PA Super-Rich	$7.3 million	20.4 Bcfe	110,000
SW PA Wet	$6.8 million	24.6 Bcfe	225,000
SW PA Dry	$6.1 million	22.3 Bcf	180,000
NE PA Dry	$5.0 million	16.0 Bcf	95,000
Total Marcellus			610,000
Upper Red	$7.7 million	17.5 Bcfe	
Lower Red	$7.7 million	11.8 Bcfe	
Total N. LA			220,000
Total			830,000

Marcellus Shale

Production for the fourth quarter of 2016 averaged approximately 1,419 net Mmcfe per day for both Marcellus Shale divisions, an 11% increase over the prior year. The Southern Marcellus Shale Division averaged 1,235 net Mmcfe per day during the quarter, a 20% increase over the prior year. The Northern Marcellus Shale Division averaged 184 net Mmcf per day during the quarter, a 25% decrease over the prior year, or a 16% decrease over the prior year when adjusted for asset sales.

Southern Marcellus Shale

The Southern Marcellus Shale division brought on line ten wells in the fourth quarter, one in the super-rich area, four in the wet area and five in the dry area. The operated rig count of five has stayed consistent throughout most of the second half of 2016, with three horizontal rigs and two air rigs.

The team continues to look for ways to reduce costs and increase recoveries. Several recent examples are shown below, which have continued to drive lower normalized well costs and reductions in operating costs per mcfe.

- Lateral lengths averaged 6,500 feet in 2016, compared to 6,100 feet in 2015, with projected lateral lengths in 2017 expected to average over 8,000 feet
- Reduced water handling costs in 2016 by over $30 million compared to 2015
- Increased lateral feet drilled per day by 40% compared to the previous year
- Reduced average completion costs per lateral foot by 14% compared to the previous year
- Managed service costs through better utilization rates and long-term vendor relationships

A recent example of what we expect when going back to core areas with longer laterals is a four well pad in the wet area brought on line in the fourth quarter, with an average 9,265 lateral length with 46 stages per well. The average peak 24 hour production rate to sales, under constrained conditions was 35.1 Mmcfe per day per well, roughly twice the average rate of the offset pads. This is a result of refined completion designs, improved landing and longer laterals. On a normalized basis, average cost per well is $651,000 per 1,000 lateral foot with average EUR per well of 3.9 Bcfe per 1,000 lateral foot. On an absolute basis, these wells represent a 47% improvement in recoveries, with an 11% reduction in cost from the average shown on page 35 in the latest investor presentation, with many additional locations expected to produce similar results.

North Louisiana

Production for the division in the fourth quarter of 2016, the first full quarter since the Memorial acquisition closing on September 16, 2016, averaged approximately 399 net Mmcfe per day, consisting of 294 Mmcf per day of gas, 13,461 barrels of NGLs per day and 3,998 barrels of condensate per day.

Since acquiring the assets, significant progress has been made operationally, including integration of personnel, information systems, communications systems and facilities. As mentioned on our third quarter conference call, Range has a new drilling team with extensive experience in high-pressure, high-temperature drilling conditions, including experience in the Vernon field. The team has been able to implement significant improvements to date. As a result, total well costs for a typical 7,500 foot lateral well drilled in Terryville have declined from $8.7 million to $7.7 million in just the past five months thereby improving returns and potentially increasing location count. In addition, these cost reductions have occurred while staying within the targeted zone, which has the potential to increase recoveries. The new targeting interval also has been reduced to approximately 30 feet, compared to 90 to 100 feet previously. Updated economics for Upper and Lower Red areas can be found in the Company presentation on slides 40, and 42, showing attractive returns at current strip pricing.

As reported in late January, three wells were drilled and completed in the extension area prior to year-end. The wells were drilled on the north, east and west sides of the Vernon field. Based on logs and cores, the wells to the east and west of Vernon field appear to be structurally similar to Vernon, with multiple, stacked pay zones, and as expected, the over pressured Lower Cotton Valley section thickens when moving south from Terryville. The eastern and western wells each encountered six pay zones with total gas in place of approximately 400 Bcf per square mile, approximately 2.5 times Terryville. Initial production results indicate that each well is expected to have a normalized gas EUR that is in line with Terryville Upper and Lower Red wells. With these encouraging results, Range will continue to analyze well data, observe production characteristics with plans to drill additional extension wells in 2017.

Marketing and Transportation

Range's overall marketing strategy for many years has been to assemble a diversified low-cost transportation portfolio. Recent developments are proving this to be a good strategy, with net pricing expected to improve on all products in 2017.

Natural gas pricing improved in the fourth quarter, with a full quarter of North Louisiana production and the addition of Spectra's Gulf Markets project going in-service in early October 2016. The project allows Range to transport 150,000 Mmbtu per day from southwest Pennsylvania to the Gulf Coast, providing a significant improvement to differentials.

Additionally, we have received favorable news regarding FERC authorizations on all remaining Appalachian takeaway projects on which Range holds capacity. Spectra's Adair Southwest project received its final FERC Certificate in the fourth quarter providing incremental transportation out of the Appalachian basin starting in late 2017. TransCanada's Leach and Rayne Express projects received their final FERC Certificates in January, with a projected in-service date in late 2017 as well. The combined capacity from these projects for Range is an additional 400,000 Mmbtu per day from the Appalachian Basin to the Gulf Coast, further improving our expected basis differentials. In addition, in early February, FERC approved Energy Transfer's Rover project. Range has 400,000 Mmbtu/day capacity on the project, with half delivered to Midwest/Canadian markets and half to the Gulf Coast. When combining this capacity with Range's North Louisiana production, which receives near NYMEX pricing, Range expects its corporate gas differential to improve to approximately $0.30 below NYMEX in 2017. In calculating the differentials, Range assumed only 400,000 Mmbtu per day of capacity would be in-service late 2017.

Range's gathering and processing costs per mcfe are expected to improve in coming years. In North Louisiana, Range acquired approximately double the processing capacity currently being utilized when the assets were acquired. Range will continue to focus the majority of its activities in the core of the Terryville area which will permit better utilization of our processing commitments in 2017, thereby reducing our minimum volume commitment expenses on a per mcfe basis. In the Marcellus, Range has largely captured the resource and is now going back to existing pads and areas of existing infrastructure, resulting in a downward trend in the Company's gathering rates per mcfe.

NGL pricing has also improved recently on better domestic market fundamentals and the Company's strong portfolio of domestic and international sales. As a result, Range's calculated NGL prices (including ethane and processing costs) for 2017 increased to a range of 28% to 30% of WTI, based on current strip pricing. This approximate 2% increase in realizations would increase pre-hedge NGL revenue by approximately $40 million for the year.

Condensate prices have improved relative to WTI as well. Condensate differentials in the fourth quarter improved to less than $5.00 per barrel, driven largely by the improvement in realizations gained through the addition of Louisiana sales and new Marcellus condensate sales agreements announced in the third quarter. Based on these results, guidance for condensate differentials in 2017 has improved to $5.00 - $6.00 below WTI.

Financial Position and Liquidity

At December 31, 2016, Range had total debt outstanding of $3.81 billion, before debt issuance costs, consisting of $2.88 billion in senior notes, $882 million in bank debt and $49 million in senior subordinated notes. Net debt outstanding, after unamortized debt issuance costs and premiums, equals $3.78 billion.

At December 31, 2016, Range's bank facility had a borrowing base of $3.0 billion, and bank commitments of $2.0 billion, with an outstanding balance of $882 million and undrawn letters of credit of $261 million, leaving $850 million of borrowing capacity available under the commitment amount.

Guidance – 2017

Production per day Guidance

Production for the first quarter of 2017 is expected to be approximately 1.92 Bcfe per day with 30% to 32% liquids.

Production for the full year 2017 is expected to average approximately 2.07 Bcfe per day. This equates to a year-over-year growth rate of 33% to 35%.

1Q 2017 Expense Guidance

Direct operating expense:	$0.18 - $0.19 per mcfe
Transportation, gathering, processing and compression expense:	$1.00 - $1.04 per mcfe
Production tax expense:	$0.05 - $0.07 per mcfe
Exploration expense:	$12.0 - $13.0 million
Unproved property impairment expense:	$6.0 - $8.0 million
G&A expense:	$0.23 - $0.25 per mcfe
Interest expense:	$0.26 - $0.28 per mcfe
DD&A expense:	$0.88 - $0.90 per mcfe
Net brokered gas marketing expense:	~$2.0 million

2017 Differentials

Based on current market pricing indications, Range expects to receive the following pre-hedge differentials for its production in 2017.

Natural Gas:	NYMEX minus $0.30
Natural Gas Liquids (including ethane):	28% - 30% of WTI
Oil/Condensate:	WTI minus $5.00 to $6.00

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. Range currently has over 75% of its expected 2017 natural gas production hedged at a weighted average floor price of $3.22 per mcf. Similarly, Range has hedged over 60% of its 2017 projected crude oil production at a floor price of $55.81 and approximately 65% 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 to limit volatility between NYMEX and regional prices. The fair value of the basis hedges as of December 31, 2016 was a gain of $11.8 million, compared to a gain of $5.5 million at December 31, 2015.

Conference Call Information

A conference call to review the financial results is scheduled on Thursday, February 23 at 9:00 a.m. ET. To participate in the call, please dial 866-900-7525 and provide conference code 48391940 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 23.

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 historically were 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.

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 reserve extensions, discoveries and additions and proved reserve revisions, excluding PUD removals based on the SEC 5-year rule.

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) adjusted for the changes in proved reserves for acquisitions, performance revisions and/or price revisions and including or excluding acreage costs 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, performance and price 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.

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.

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 merger integration, 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"), which are incorporated by reference. Range undertakes no obligation to publicly update or revise any forward-looking statements.*

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.

2017-04

SOURCE: Range Resources Corporation

Investor Contacts:

Laith Sando, Vice President – Investor Relations
817-869-4267
lsando@rangeresources.com

David Amend, Investor Relations Manager
817-869-4266
damend@rangeresources.com

Michael Freeman, Senior Financial Analyst
817-869-4264
mfreeman@rangeresources.com

Josh Stevens, Financial Analyst
817-869-1564
jrstevens@rangeresources.com

Media Contact:

Michael Mackin, Director of Public Affairs
724-873-3224
mmackin@rangeresources.com

www.rangeresources.com

STATEMENTS OF OPERATIONS
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 Decemb	
	2016	2015	%	2016	2015
Revenues and other income:					
Natural gas, NGLs and oil sales (a)	$ 458,645	$ 254,043		$ 1,197,215	$ 1,089,644
Derivative fair value (loss)/income	(250,057)	126,312		(261,391)	416,364
Brokered natural gas, marketing and other (b)	44,774	30,100		163,219	90,922
ARO settlement gain (loss) (b)	54	80		40	103
Other (b)	106	192		856	1,035
Total revenues and other income	253,522	410,727	-38%	1,099,939	1,598,068
Costs and expenses:					
Direct operating	29,755	28,757		95,086	133,583
Direct operating – non-cash stock-based compensation (c)	521	631		2,302	2,780
Transportation, gathering, processing and compression	164,338	112,481		565,209	396,739
Production and ad valorem taxes	6,790	7,354		25,443	33,860
Brokered natural gas and marketing	46,095	34,553		166,851	113,734
Brokered natural gas and marketing – non-cash stock-based compensation (c)	376	389		1,725	2,132
Exploration	13,055	3,446		30,027	18,421
Exploration – non-cash stock-based compensation (c)	629	814		2,298	2,985
Abandonment and impairment of unproved properties	6,307	11,432		30,076	47,619
General and administrative	44,285	29,476		132,104	136,290
General and administrative – non-cash stock-based compensation (c)	11,611	11,142		49,293	49,687
General and administrative – lawsuit settlements	1,131	1,226		2,575	3,238
General and administrative – bad debt expense	—	1,700		800	2,300
General and administrative – DEP penalty	—	—		—	2,500
Memorial merger expenses	813	—		37,225	—
Termination costs	(822)	10,283		(519)	14,853
Termination costs – non-cash stock-based compensation (c)	—	(1,503)		—	217
Deferred compensation plan (d)	(11,013)	(21,016)		19,153	(77,627)
Interest expense	46,749	40,849		168,213	166,439
Loss on early extinguishment of debt	—	—		—	22,495
Depletion, depreciation and amortization	149,662	127,977		524,102	581,155
Impairment of proved properties and other assets	—	87,941		43,040	590,174
(Gain) loss on sale of assets	(470)	408,909		7,074	406,856
Total costs and expenses	509,812	896,841	-43%	1,902,077	2,650,430
Loss before income taxes	(256,290)	(486,114)	47%	(802,138)	(1,052,362)
Income tax benefit:					
Current	98	29		98	29
Deferred	(95,679)	(164,316)		(280,848)	(338,706)
	(95,581)	(164,287)		(280,750)	(338,677)
Net loss	$ (160,709)	$ (321,827)	50%	$ (521,388)	$ (713,685)
Net Loss Per Common Share:					
Basic	$ (0.66)	$ (1.93)		$ (2.75)	$ (4.29)
Diluted	$ (0.66)	$ (1.93)		$ (2.75)	$ (4.29)
Weighted average common shares outstanding, as reported:					
Basic	244,362	166,573	47%	189,868	166,389
Diluted	244,362	166,573	47%	189,868	166,389

(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.

BALANCE SHEETS
(Audited, In thousands)

		December 31, 2016		December 31, 2015
Assets				
Current assets	$	268,605	$	157,530
Derivative assets		13,483		288,762
Goodwill		1,654,292		—
Natural gas and oil properties, successful efforts method		9,256,337		6,361,305
Transportation and field assets		16,873		19,455
Other		72,655		72,979
	$	11,282,245	$	6,900,031
Liabilities and Stockholders' Equity				
Current liabilities	$	530,373	$	335,513
Asset retirement obligations		7,271		15,071
Derivative liabilities		165,009		1,136
Bank debt		876,428		86,427
Senior notes		2,848,591		738,101
Senior subordinated notes		48,498		1,826,775
Total debt		3,773,517		2,651,303
Deferred tax liability		943,343		777,947
Derivative liabilities		24,491		21
Deferred compensation liability		119,231		104,792
Asset retirement obligations and other liabilities		310,642		254,590
Common stock and retained earnings		5,409,577		2,761,903
Common stock held in treasury stock		(1,209)		(2,245)
Total stockholders' equity		5,408,368		2,759,658
	$	11,282,245	$	6,900,031

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			
		2016		2015	%		2016		2015
Total revenues and other income, as reported	$	253,522	$	410,727	-38%	$	1,099,939	$	1,598
Adjustment for certain special items:									
Total change in fair value related to derivatives prior to settlement loss		336,736		45,165			608,727		115
ARO settlement (gain) loss		(54)		(80)			(40)		
Total revenues, as adjusted, non-GAAP	$	590,204	$	455,812	30%	$	1,708,626	$	1,713

CASH FLOWS FROM OPERATING ACTIVITIES
(Unaudited in thousands)

	Three Months Ended December 31,		Twelve Months Ended	
	2016	2015	2016	
Net loss	$ (162,771)	$ (321,827)	$ (521,388)	$
Adjustments to reconcile net cash provided from continuing operations:				
Deferred income tax benefit	(93,617)	(164,316)	(280,848)	
Depletion, depreciation, amortization and impairment	149,662	215,918	567,142	
Exploration dry hole costs	16	1	18	
Abandonment and impairment of unproved properties	6,307	11,432	30,076	
Derivative fair value loss (income)	250,057	(126,312)	261,391	
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	86,679	171,477	347,336	
Allowance for bad debts	—	1,700	800	
Amortization of deferred issuance costs, loss on extinguishment of debt and other	1,787	1,811	7,170	
Deferred and stock-based compensation	1,996	(9,732)	74,685	
(Gain) loss on sale of assets and other	(470)	408,909	7,074	
Changes in working capital:				
Accounts receivable	(52,571)	(14,744)	(20,586)	
Inventory and other	6,996	(7,795)	6,220	
Accounts payable	14,009	(13,039)	(27,259)	
Accrued liabilities and other	(23,049)	22,359	(64,763)	
Net changes in working capital	(54,615)	(13,219)	(106,388)	
Net cash provided from operating activities	$ 185,031	$ 175,842	$ 387,068	$

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	
	2016	2015	2016	
Net cash provided from operating activities, as reported	$ 185,031	$ 175,842	$ 387,068	$
Net changes in working capital	54,615	13,219	106,388	
Exploration expense	13,039	3,445	30,009	
Lawsuit settlements	1,131	1,226	2,575	
Cash paid to exchange senior subordinated notes	—	—	6,600	
Legal contingency/DEP penalty	—	—	—	
Memorial merger expenses	813	—	37,225	
Termination costs	(822)	10,283	(519)	
Non-cash compensation adjustment	56	73	19	
Cash flow from operations before changes in working capital – non-GAAP measure	$ 253,863	$ 204,088	$ 569,365	$

ADJUSTED WEIGHTED AVERAGE SHARES OUTSTANDING
(Unaudited, in thousands)

	Three Months Ended December 31,		Twelve Months Ended Decemb	
	2016	2015	2016	
Basic:				
Weighted average shares outstanding	247,161	169,371	192,661	
Stock held by deferred compensation plan	(2,799)	(2,798)	(2,793)	
Adjusted basic	244,362	166,573	189,868	
Dilutive:				
Weighted average shares outstanding	247,161	169,371	192,661	
Dilutive stock options under treasury method	(2,799)	(2,798)	(2,793)	
Adjusted dilutive	244,362	166,573	189,868	

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, PROCESSING AND COMPRESSION FEES, a non-GAAP measure
(Unaudited, in thousands, except per unit data)

	Three Months Ended December 31,			Twelve Months Ended December	
	2016	2015	%	2016	2015
Natural gas, NGLs and oil sales components:					
Natural gas sales	$ 289,790	$ 183,576		$ 753,888	$ 773,093
NGLs sales	119,585	44,724		318,462	176,546
Oil sales	49,270	25,743		124,865	140,005
Total natural gas, NGL sales, as reported	$ 458,645	$ 254,043	81%	$ 1,197,215	$ 1,089,644
Derivative fair value income (loss), as reported:	$ (250,057)	$ 126,312		$ (261,391)	$ 416,364
Cash settlements on derivative financial instruments – (gain) loss:					
Natural gas	(46,015)	(115,428)		(252,000)	(339,031)
NGLs	(22,231)	(10,366)		(47,626)	(41,974)
Crude Oil	(18,433)	(45,683)		(47,710)	(151,117)
Total change in fair value related to derivatives prior to settlement, a non-GAAP measure	$ (336,736)	$ (45,165)		$ (608,727)	$ (115,758)
Transportation, gathering, processing and compression components:					
Natural gas	$ 114,854	$ 95,849		$ 403,209	$ 343,593
NGLs	49,484	16,632		162,000	53,146
Total transportation, gathering, processing and compression, as reported	$ 164,338	$ 112,481		$ 565,209	$ 396,739
Natural gas, NGL and oil sales, including cash-settled derivatives: (c)					
Natural gas sales	$ 335,805	$ 299,004		$ 1,005,888	$ 1,112,124
NGLs sales	141,816	55,090		366,088	218,520
Oil sales	67,703	71,426		172,575	291,122
Total	$ 545,324	$ 425,520	28%	$ 1,544,551	$ 1,621,766
Production of oil and gas during the periods (a):					
Natural gas (mcf)	114,480,336	97,175,602	18%	375,811,462	362,686,707
NGLs (bbl)	8,245,792	4,906,615	68%	27,825,635	20,356,110
Oil (bbl)	1,104,414	897,064	23%	3,609,171	4,084,069
Gas equivalent (mcfe) (b)	170,581,572	131,997,676	29%	564,420,298	509,327,781
Production of oil and gas – average per day (a):					
Natural gas (mcf)	1,244,351	1,056,257	18%	1,026,807	993,662
NGLs (bbl)	89,628	53,333	68%	76,026	55,770
Oil (bbl)	12,005	9,751	23%	9,861	11,189
Gas equivalent (mcfe) (b)	1,854,148	1,434,757	29%	1,542,132	1,395,419
Average prices, including cash-settled hedges that qualify for hedge accounting before third party transportation costs:					
Natural gas (mcf)	$ 2.53	$ 1.89	34%	$ 2.01	$ 2.13
NGLs (bbl)	$ 14.50	$ 9.12	59%	$ 11.44	$ 8.67
Oil (bbl)	$ 44.61	$ 28.70	55%	$ 34.60	$ 34.28
Gas equivalent (mcfe) (b)	$ 2.69	$ 1.92	40%	$ 2.12	$ 2.14
Average prices, including cash-settled hedges and derivatives before third party transportation costs: (c)					
Natural gas (mcf)	$ 2.93	$ 3.08	-5%	$ 2.68	$ 3.07
NGLs (bbl)	$ 17.20	$ 11.23	53%	$ 13.16	$ 10.73
Oil (bbl)	$ 61.30	$ 79.62	-23%	$ 47.82	$ 71.28
Gas equivalent (mcfe) (b)	$ 3.20	$ 3.22	-1%	$ 2.74	$ 3.18
Average prices, including cash-settled hedges and derivatives: (d)					
Natural gas (mcf)	$ 1.93	$ 2.09	-8%	$ 1.60	$ 2.12
NGLs (bbl)	$ 11.20	$ 7.84	43%	$ 7.33	$ 8.12
Oil (bbl)	$ 61.30	$ 79.62	-23%	$ 47.82	$ 71.28
Gas equivalent (mcfe) (b)	$ 2.23	$ 2.37	-6%	$ 1.74	$ 2.41
Transportation, gathering, processing and compression expense per mcfe	$ 0.96	$ 0.85	13%	$ 1.00	$ 0.78

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

RECONCILIATION OF INCOME 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 Dec	
	2016	2015	%	2016	2015
Loss from operations before income taxes, as reported	$ (256,290)	$ (486,114)	47%	$ (802,138)	$ (1,052
Adjustment for certain special items:					
(Gain) loss on sale of assets	(470)	408,909		7,074	406
(Gain) loss on ARO settlements	(54)	(80)		(40)	(
Change in fair value related to derivatives prior to settlement	336,736	45,165		608,727	115
Abandonment and impairment of unproved properties	6,307	11,432		30,076	47
Loss on early extinguishment of debt	—	—		—	22
Impairment of proved property	—	87,941		43,040	590
Lawsuit settlements	1,131	1,226		2,575	3
Fees paid to exchange senior subordinated notes	—	—		6,600	
DEP penalty	—	—		—	2
Memorial merger expenses	813	—		37,225	
Termination costs	(822)	10,283		(519)	14
Termination costs – non-cash stock-based compensation	—	(1,503)		—	
Brokered natural gas and marketing – non-cash stock-based compensation	376	389		1,725	2
Direct operating – non-cash stock-based compensation	521	631		2,302	2
Exploration expenses – non-cash stock-based compensation	629	814		2,298	2
General & administrative – non-cash stock-based compensation	11,611	11,142		49,293	49
Deferred compensation plan – non-cash adjustment	(11,013)	(21,016)		19,153	(77
Income before income taxes, as adjusted	89,475	69,219	29%	7,391	131
Income tax expense, as adjusted					
Current	98	29		98	
Deferred (a)	33,759	27,431		2,426	50
Net income excluding certain items, a non-GAAP measure	$ 55,618	$ 41,759	33%	$ 4,867	$ 80
Non-GAAP income (loss) per common share					
Basic	$ 0.23	$ 0.25	-8%	$ 0.03	$
Diluted	$ 0.23	$ 0.25	-8%	$ 0.03	$
Non-GAAP diluted shares outstanding, if dilutive	244,761	166,881		189,911	166

(a) Deferred taxes for 2016 are estimated to be approximately 38%.

HEDGING POSITION AS OF FEBRUARY 17, 2017
(Unaudited) –

	Daily Volume	Hedge Price
Gas		
2017 Swaps	830,171 Mmbtu	$3.17
2017 Puts (1)	175,890 Mmbtu	$3.17
2017 Collars	117,123 Mmbtu	$3.48 x $4.15
1Q 2018 Swaps	830,000 Mmbtu	$3.42
2Q-4Q 2018 Swaps	225,000 Mmbtu	$2.97
Oil		
2017 Swaps	8,795 bbls	$55.81
2018 Swaps	3,000 bbls	$54.36
C2 Ethane		
2017 Swaps	3,000 bbls	$0.27/gallon
C3 Propane (2)		
2017 Swaps	13,974 bbls	$0.56/gallon
2018 Swaps	7,199 bbls	$0.61/gallon
C4 Normal Butane		
2017 Swaps	7,731 bbls	$0.74/gallon
2018 Swaps	4,250 bbls	$0.81/gallon
C5 Natural Gasoline		
2017 Swaps	5,250 bbls	$01.06/gallon
2017 Swaps	1,500 bbls	$01.19/gallon

(1) Net of deferred premiums
(2) Incorporates international propane spreads

NOTE: SEE WEBSITE FOR OTHER SUPPLEMENTAL INFORMATION FOR THE PERIODS