**QEP RESOURCES REPORTS THIRD QUARTER 2016 FINANCIAL AND OPERATING RESULTS**

- Increased full-year production guidance for crude oil, natural gas and NGL
- Completed five gross-operated Spraberry Shale wells, with an average peak 24-hour IP of 1,258 Boed
- Delivered solid results from "wine-rack" geometry well density Spraberry Shale test
- Added two additional rigs in the Permian Basin on legacy acreage (County Line)
- Maintained strong liquidity with over $1.0 billion in cash and cash equivalents at quarter-end
- Closed Permian Basin acquisition (Mustang Springs) for approximately $590.0 million on October 19, 2016

**DENVER** — October 26, 2016 — QEP Resources, Inc. (NYSE:QEP) (QEP or the Company) today reported third quarter 2016 financial and operating results. The Company reported a net loss of $50.9 million, or $0.21 per diluted share, for the third quarter 2016 compared with net income of $21.1 million, or $0.12 per diluted share, for the third quarter 2015. The net loss was primarily due to a decrease in average realized prices and increased general and administrative expenses, partially offset by decreased depreciation, depletion and amortization and decreased lease operating expense for the third quarter 2016 compared with the third quarter 2015.

Net loss includes non-cash gains and losses associated with the change in the fair value of derivative instruments, gains and losses from asset sales, asset impairments and certain other items. Excluding these items, the Company's third quarter 2016 Adjusted Net Loss (a non-GAAP measure) was $51.1 million, or $0.21 per diluted share, compared with Adjusted Net Income of $1.0 million, or $0.01 per diluted share, for the third quarter 2015.

Adjusted EBITDA (a non-GAAP measure) for the third quarter 2016 was $168.7 million compared with $273.1 million for the third quarter 2015, a 38% decrease, primarily due to a decrease in average realized prices, partially offset by decreased lease operating expense. The definitions and reconciliations of Adjusted Net Loss and Adjusted EBITDA to net income (loss) are provided within the financial tables at the end of this release.

"Our County Line acreage in the Permian Basin continued to deliver strong well performance during the quarter, including promising results on our initial "wine-rack" geometry well density test targeting the "A" and "C" benches of the Spraberry Shale," commented Chuck Stanley, Chairman, President and CEO of QEP. "During the quarter, we increased our operated horizontal rig count in the Permian to three rigs and expect this number to grow to five rigs in the basin during 2017. Our planned drilling program will allow us to continue developing our County Line acreage while simultaneously increasing our activity on the newly acquired Mustang Springs acreage.

"The assets across our portfolio continue to exceed expectations and as a result we have increased full-year production guidance for crude oil, natural gas and NGL. Over the last two years we have worked diligently, through capital discipline and portfolio rationalization, to position QEP to increase production and generate strong returns going forward. Our solid balance sheet allows us to accelerate crude oil production in 2017, largely through our newly expanded Permian Basin asset, with the optionality to grow natural gas production without the need to incur incremental indebtedness. We remain focused on simplifying our asset portfolio while continuing to grow our crude oil exposure both organically and through acquisitions," concluded Stanley.

Slides for the third quarter 2016 with maps and other supporting materials referred to in this release are posted on the Company's website at www.qepres.com.

## QEP Financial Results Summary

- Natural gas equivalent production was stable at 86.6 Bcfe for the third quarter 2016 compared with 86.7 Bcfe for the third quarter 2015. Pinedale and the Uinta Basin had decreased production while the Williston and Permian basins and Haynesville/Cotton Valley had increased production.
- Natural gas and crude oil production both decreased 3%, while NGL production increased 26% in the third quarter 2016 compared with the third quarter 2015. Third quarter 2016 natural gas and crude oil production was negatively impacted by fewer completions in Pinedale and the Williston Basin. NGL production was higher, primarily due to a third-party midstream provider's decision to continue to operate in ethane recovery in the Williston Basin, and in the Permian Basin due to an overall increase in production.
- Field-level revenues decreased 4% in the third quarter 2016 compared with the third quarter 2015, due to lower crude oil, natural gas and NGL field-level prices and lower crude oil and natural gas production. Crude oil and NGL production accounted for 64% of field-level revenues in the third quarter 2016.
- Capital investment, excluding acquisitions (on an accrual basis), for the third quarter 2016 was $141.9 million compared with $257.5 million for the third quarter 2015. For the first nine months of 2016, capital investment, excluding acquisitions (on an accrual basis), was $384.6 million, down $409.1 million compared with the first nine months of 2015.
- During the quarter, the Company invested $16.3 million to acquire various oil and gas properties, primarily consisting of proved undeveloped leasehold acreage in the Williston Basin.
- Cash and cash equivalents were $1,032.2 million at the end of the third quarter 2016 and the Company had no borrowings under its unsecured revolving credit facility.
- General and administrative expense for the third quarter 2016 was $67.0 million, an increase of 60% compared with the third quarter 2015, driven primarily by an increase in loss contingencies.

## 2016 Permian Acquisition Update

On October 19, 2016, QEP closed on its previously announced acquisition of approximately 9,400 net acres in the Permian Basin in Martin County, Texas, for total consideration of approximately $590.0 million, subject to customary purchase price adjustments. The acreage is located 10 miles east of existing QEP operations in the core of the northern Midland Basin where QEP has identified potential for over 430 unrisked horizontal drilling locations in four target reservoirs, with potential upside in additional zones.

**QEP 2016 Guidance**

The updated 2016 guidance provided below is predicated on the following assumptions:

- Five operated rigs for the remainder of 2016: three in the Permian Basin, one in the Williston Basin and one at Pinedale

| | 2016 Previous Forecast | 2016 Current Forecast |
|---|---|---|
| Oil production (MMbbl) | 19.5 - 20.5 | 20.5 |
| NGL production (MMbbl) | 4.75 - 5.25 | 6.0 |
| Natural gas production (Bcf) | 165 - 175 | 178 |
| Total natural gas equivalent production (Bcfe) | 311 - 330 | 337 |
| Lease operating and transportation expense (per Mcfe) | \$1.60 - \$1.70 | \$1.50 - \$1.60 |
| Depletion, depreciation and amortization (per Mcfe) | \$2.55 - \$2.80 | \$2.50 - \$2.80 |
| Production and property taxes (% of field-level revenue) | 8.5% | 8.5% |
| **(in millions)** | | |
| General and administrative expense[1] | \$165 - \$175 | \$200 - \$210 |
| Capital investment (excluding acquisitions) | \$500 - \$550 | \$525 - \$550 |

(1) Forecasted general and administrative expense includes approximately \$45.0 million of non-cash expenses primarily related to share-based compensation and approximately \$35.0 million of restructuring and legal expenses and loss contingencies.

## Operations Summary

The table below presents a summary of QEP-operated and non-operated well completions for the three and nine months ended September 30, 2016:

| | Operated Completions | | | | Non-operated Completions | | | |
|---|---|---|---|---|---|---|---|---|
| | Three Months Ended September 30, 2016 | | Nine Months Ended September 30, 2016 | | Three Months Ended September 30, 2016 | | Nine Months Ended September 30, 2016 | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| **Northern Region** | | | | | | | | |
| Pinedale | 34 | 18.4 | 38 | 21.8 | — | — | — | — |
| Williston Basin | 9 | 7.8 | 27 | 25.6 | 16 | 1.0 | 23 | 1.0 |
| Uinta Basin | — | — | 8 | 8.0 | — | — | 2 | 0.0 |
| Other Northern | — | — | — | — | — | — | — | — |
| | | | | | | | | |
| **Southern Region** | | | | | | | | |
| Haynesville/Cotton Valley | — | — | — | — | — | — | 9 | 1.8 |
| Permian Basin | 5 | 5.0 | 18 | 17.7 | — | — | — | — |
| Other Southern | — | — | — | — | — | — | — | — |

### Permian Basin

Permian Basin net production averaged 16.3 Mboed (86% liquids) during the third quarter 2016, a 6% decrease compared with the second quarter 2016 and a 23% increase compared with the third quarter 2015. QEP completed and turned to sales five gross-operated horizontal wells during the third quarter 2016 (average working interest 100%) with an average peak 24-hour IP of 1,258 Boed from an average lateral length of 7,306 feet. All five wells were completed in the Spraberry Shale.

During the quarter, the Company continued its initial "wine-rack" geometry well density test targeting the "A" and "C" benches of the Spraberry Shale on its County Line acreage. The Company has now completed a total of eight wells in the pilot. The test wells are comprised of four wells in each of the “A” and “C” benches with a spacing pattern designed to evaluate 10-wells per one-mile spacing unit density in the Spraberry Shale. The average peak 24-hour IP for these eight wells was 1,291 Boed and after over two months on production, the wells continue to perform consistent with or better than nearby parent wells.

At the end of the third quarter 2016, the Company had two gross-operated horizontal wells waiting on completion (average working interest 90%) and five gross-operated horizontal wells being drilled (average working interest 100%); two each in the "A" and "C" benches of the Spraberry Shale as part of a second "wine-rack" geometry well density test, and one in the Leonard Shale.

Current average gross QEP-operated drilled and completed authorization for expenditure (AFE) well costs are $4.9 million for 7,500 foot Spraberry wells, with costs associated with facilities and artificial lift adding approximately $0.7 million per well. At the end of the third quarter, the Company had three operated rigs in the Permian Basin on its County Line acreage, two drilling horizontal wells and one "rigging up".

Slides 4-11 depict QEP's acreage and activity in the Permian Basin.

### Williston Basin

Williston Basin net production averaged approximately 57.1 Mboed (86% liquids) during the third quarter 2016, a 1% decrease compared with the second quarter 2016 and a 6% increase compared with the third quarter 2015. The Company completed and turned to sales nine gross-operated wells, six in South Antelope and three at Ft. Berthold, during the third quarter 2016 (average working interest 87%). The South Antelope completions occurred late in the third quarter 2016 and did not contribute materially to the overall production from the Williston Basin during the quarter. Production during the quarter was impacted by increased downtime due to offset frac shut-ins and increased workover activity.

The Company continues to target the second and third benches of the Three Forks Formation with two new second bench wells and one new third bench well brought online at the end of the third quarter in South Antelope. The only well of the three with enough time on production was a second bench well, which reached a peak 24-hour IP of 2,871 Boed. The four longest producing second bench wells have generated average cumulative production of 297 Mboe per well in the first 270 days online. Similarly, the longest producing third bench well has produced 282 Mboe in its first 240 days of production. At the end of the third quarter 2016, there were five wells in the second bench and three wells in the third bench waiting on completion.

During the quarter, the Company completed three wells at Ft. Berthold utilizing a more modern completion design than used for previous Ft. Berthold wells. These wells are performing in-line with updated expectations and delivered an average peak 24-hour IP of 1,380 Boed. The Company believes the recent well results utilizing the new completion design further validates the quality of the acreage position at Ft. Berthold and will ultimately add to the remaining inventory on the acreage.

At the end of the third quarter 2016, QEP had 23 gross operated horizontal wells waiting on completion in the Williston Basin (average working interest 83%), all in South Antelope and four gross-operated horizontal wells being drilled (average working interest 93%) at Ft. Berthold. Of the 23 wells waiting on completion, 13 were sliding sleeve and 10 were "plug-and-perf" designs. In addition, the Company had interests in 12 gross non-operated horizontal wells waiting on completion (average working interest 11%) at the end of the quarter.

An ongoing commercial dispute with the entity that purchases, gathers and processes natural gas produced from oil wells on the Company's South Antelope acreage negatively impacted completion activities and production volumes during the third quarter 2016. Due to this dispute, the pace at which the Company is able to complete additional drilled and uncompleted wells during the fourth quarter of 2016 in South Antelope in the Williston Basin will be impacted. Unless the parties resolve the dispute amicably, the matter will be decided by binding arbitration, which will likely conclude in the fourth quarter 2016.

Current average gross QEP-operated drilled and completed AFE well costs, assuming "plug-and-perf" completion design, are $5.5 million at South Antelope and $6.0 million at Ft. Berthold, with costs associated with facilities and artificial lift adding approximately $0.8 million per well in South Antelope and $1.1 million per well at Ft. Berthold. At the end of the third quarter 2016, the Company had one operated rig working in the Williston Basin at Ft. Berthold.

Slides 12-17 depict QEP's acreage and activity in the Williston Basin.

**Pinedale**

Pinedale net production averaged 261 MMcfed (12% liquids) during the third quarter 2016, a 4% increase compared with the second quarter 2016 and a 9% decrease compared with the third quarter 2015. There were 34 operated wells completed and turned to sales during the third quarter 2016 (average working interest 54%).

At the end of the third quarter 2016, the Company had six gross-operated Pinedale wells waiting on completion (average working interest 43%) and eight wells being drilled (average working interest 56%).

Current average gross QEP-operated drilled and completed AFE well costs are $2.7 million in Pinedale, with costs associated with facilities and plunger lift adding approximately $0.2 million per well. At the end of the third quarter, the Company had one operated rig running in Pinedale.

Slides 18-20 depict QEP's acreage and activity in Pinedale.

**Haynesville/Cotton Valley**

Haynesville/Cotton Valley net production averaged 133 MMcfed during third quarter 2016, a 31% increase compared with the second quarter 2016 and a 9% increase compared with the third quarter 2015. The increase is primarily due to recent well workovers, changes in working interest as a result of resolution of certain title issues, non-operated well completions and other production related adjustments.

At the end of the third quarter, the Company had no rigs operating in the Haynesville/Cotton Valley.

Slides 21-22 depict QEP's acreage and activity in Haynesville/Cotton Valley.

**Uinta Basin**

Uinta Basin net production averaged 79 MMcfed (21% liquids) during the third quarter 2016, of which 50 MMcfed (9% liquids) was from the Lower Mesaverde play. This represents a 9% decrease compared with the second quarter 2016 and an 18% decrease compared with the third quarter 2015.

At the end of the third quarter, the Company had no rigs operating in the Uinta Basin.

Slides 23-24 depict QEP's acreage and activity in the Lower Mesaverde play in the Uinta Basin.

## Third Quarter 2016 Results Conference Call

QEP's management will discuss third quarter 2016 results in a conference call on Thursday, October 27, 2016, beginning at 9:00 a.m. EDT. The conference call can be accessed at www.qepres.com. You may also participate in the conference call by dialing (877) 869-3847 in the U.S. or Canada and (201) 689-8261 for international calls. A replay of the teleconference will be available on the website immediately after the call through November 27, 2016, or by dialing (877) 660-6853 in the U.S. or Canada and (201) 612-7415 for international calls, and then entering the conference ID # 13646387. In addition, QEP's slides for the third quarter 2016, with updated maps showing QEP's leasehold and current activity for key operating areas discussed in this release, can be found on the Company's website.

## About QEP Resources, Inc.

QEP Resources, Inc. (NYSE:QEP) is an independent natural gas and crude oil exploration and production company focused in two regions of the United States: the Northern Region (primarily in Wyoming, North Dakota and Utah) and the Southern Region (primarily Texas and Louisiana). For more information, visit QEP's' website at: www.qepres.com.

**Forward-Looking Statements**

This release includes forward-looking statements within the meaning of Section 27(a) of the Securities Act of 1933, as amended, and Section 21(e) of the Securities Exchange Act of 1934, as amended. Forward-looking statements can be identified by words such as “anticipates,” “believes,” “forecasts,” “plans,” “estimates,” “expects,” “should,” “will” or other similar expressions. Such statements are based on management’s current expectations, estimates and projections, which are subject to a wide range of uncertainties and business risks. These forward-looking statements include, but are not limited to, statements regarding: our 2016 capital investment budget; the number and location of drilling rigs; positioning QEP for growth; liquidity; advantages of a strong balance sheet; simplifying QEP’s asset portfolio and growing crude oil exposure; anticipated production levels; the quality of our E&P asset portfolio; our focus on capital discipline; expected gross completed well costs and additional costs for facilities and artificial lift; forecasted production amounts, lease operating and transportation expense, depletion, depreciation and amortization expense, general and administrative expense, and production and property taxes, and related assumptions for such guidance; our extensive inventory of drilling locations; additional drilling inventory from the 2016 Permian Acquisition; and the use and importance of non-GAAP financial measures. Actual results may differ materially from those included in the forward-looking statements due to a number of factors, including, but not limited to: changes in natural gas, NGL and oil prices; liquidity constraints, including those resulting from the cost or unavailability of financing due to debt and equity capital and credit market conditions, changes in our credit rating, our compliance with loan covenants, the increasing credit pressure on our industry or demands for cash collateral by counterparties to derivative and other contracts; global geopolitical and macroeconomic factors; the activities of the Organization of Petroleum Exporting Countries (OPEC), including the ability of members of OPEC to agree to and maintain oil price and production controls and the ability of Iran to market its oil following the lifting of trade sanctions; the impact of Brexit; general economic conditions, including interest rates; changes in local, regional, national and global demand for natural gas, oil and NGL; changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning the environment, climate change, greenhouse gas or other emissions, natural resources, and fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures; impact of U.S. dollar exchange rates on oil, NGL and natural gas prices; elimination of federal income tax deductions for oil and gas exploration and development; drilling results; shortages of oilfield equipment, services and personnel; the availability of storage and refining capacity; operating risks such as unexpected drilling conditions; transportation constraints; weather conditions; changes in maintenance, service and construction costs; permitting delays; outcome of contingencies such as legal proceedings; inadequate supplies of water and/or lack of water disposal sources; and the other risks discussed in the Company’s periodic filings with the Securities and Exchange Commission, including the Risk Factors section of the Company’s Annual Report on Form 10-K for the year ended December 31, 2015, and Quarterly Report on Form 10-Q for the quarter ended September 30, 2016. QEP Resources undertakes no obligation to publicly correct or update the forward-looking statements in this news release, in other documents, or on the website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

**Contact**


Investors:
William I. Kent, IRC
Director, Investor Relations
303-405-6665

Media:
Brent Rockwood
Director, Communications
303-672-6999

**QEP RESOURCES, INC.**
**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**
**(Unaudited)**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| **REVENUES** | (in millions, except per share amounts) | | | |
| Gas sales | **$ 123.2** | $ 129.4 | **$ 287.5** | $ 363.3 |
| Oil sales | **201.6** | 211.7 | **553.1** | 640.9 |
| NGL sales | **19.8** | 16.5 | **56.2** | 61.7 |
| Other revenue | **2.5** | 2.8 | **4.3** | 12.4 |
| Purchased gas and oil sales | **35.3** | 147.2 | **76.3** | 472.0 |
| Total Revenues | **382.4** | 507.6 | **977.4** | 1,550.3 |
| **OPERATING EXPENSES** | | | | |
| Purchased gas and oil expense | **37.1** | 146.0 | **80.8** | 475.1 |
| Lease operating expense | **50.7** | 56.7 | **163.3** | 175.6 |
| Gas, oil and NGL transportation and other handling costs | **75.8** | 78.1 | **218.9** | 216.2 |
| Gathering and other expense | **0.9** | 1.3 | **3.8** | 4.4 |
| General and administrative | **67.0** | 42.0 | **159.4** | 140.7 |
| Production and property taxes | **26.8** | 30.2 | **65.3** | 90.7 |
| Depreciation, depletion and amortization | **217.8** | 238.1 | **667.5** | 649.3 |
| Exploration expenses | **0.2** | 0.8 | **0.9** | 2.7 |
| Impairment | **5.0** | 15.0 | **1,188.2** | 35.5 |
| Total Operating Expenses | **481.3** | 608.2 | **2,548.1** | 1,790.2 |
| Net gain (loss) from asset sales | **5.3** | 12.9 | **5.0** | 6.9 |
| OPERATING INCOME (LOSS) | **(93.6)** | (87.7) | **(1,565.7)** | (233.0) |
| Realized and unrealized gains (losses) on derivative contracts | **44.5** | 153.6 | **(85.1)** | 168.5 |
| Interest and other income (expense) | **5.1** | 0.3 | **7.1** | 1.5 |
| Interest expense | **(35.9)** | (36.4) | **(109.2)** | (109.4) |
| INCOME (LOSS) BEFORE INCOME TAXES | **(79.9)** | 29.8 | **(1,752.9)** | (172.4) |
| Income tax (provision) benefit | **29.0** | (8.7) | **641.2** | 61.6 |
| NET INCOME (LOSS) | **$ (50.9)** | $ 21.1 | **$ (1,111.7)** | $ (110.8) |
| | | | | |
| Earnings (loss) per common share | | | | |
| Basic | **$ (0.21)** | $ 0.12 | **$ (5.15)** | $ (0.63) |
| Diluted | **$ (0.21)** | $ 0.12 | **$ (5.15)** | $ (0.63) |
| | | | | |
| Weighted-average common shares outstanding | | | | |
| Used in basic calculation | **239.6** | 176.7 | **215.7** | 176.5 |
| Used in diluted calculation | **239.6** | 176.7 | **215.7** | 176.5 |
| Dividends per common share | **$ —** | $ 0.02 | **$ —** | $ 0.06 |

**QEP RESOURCES, INC.**
**CONDENSED CONSOLIDATED BALANCE SHEETS**
**(Unaudited)**

| | September 30, 2016 | December 31, 2015 |
|---|---|---|
| **ASSETS** | (in millions) | |
| Current Assets | | |
| Cash and cash equivalents | $ 1,032.2 | $ 376.1 |
| Accounts receivable, net | 135.6 | 278.2 |
| Income tax receivable | 22.5 | 87.3 |
| Fair value of derivative contracts | 0.5 | 146.8 |
| Gas, oil and NGL inventories, at lower of average cost or market | 10.8 | 13.3 |
| Prepaid expenses and other | 7.4 | 30.1 |
| Total Current Assets | 1,209.0 | 931.8 |
| Property, Plant and Equipment (successful efforts method for gas and oil properties) | | |
| Proved properties | 13,684.0 | 13,314.9 |
| Unproved properties | 658.5 | 691.0 |
| Gathering and other | 300.7 | 297.9 |
| Materials and supplies | 31.7 | 38.5 |
| Total Property, Plant and Equipment | 14,674.9 | 14,342.3 |
| Less Accumulated Depreciation, Depletion and Amortization | | |
| Exploration and production | 8,604.7 | 6,870.2 |
| Gathering and other | 99.6 | 87.5 |
| Total Accumulated Depreciation, Depletion and Amortization | 8,704.3 | 6,957.7 |
| Net Property, Plant and Equipment | 5,970.6 | 7,384.6 |
| Fair value of derivative contracts | — | 23.2 |
| Other noncurrent assets | 95.6 | 58.6 |
| TOTAL ASSETS | $ 7,275.2 | $ 8,398.2 |
| | | |
| **LIABILITIES AND EQUITY** | | |
| Current Liabilities | | |
| Checks outstanding in excess of cash balances | $ 4.3 | $ 29.8 |
| Accounts payable and accrued expenses | 259.3 | 351.7 |
| Production and property taxes | 40.3 | 46.1 |
| Interest payable | 32.8 | 36.4 |
| Fair value of derivative contracts | 34.5 | 0.8 |
| Current portion of long-term debt | — | 176.8 |
| Total Current Liabilities | 371.2 | 641.6 |
| Long-term debt | 2,019.3 | 2,014.7 |
| Deferred income taxes | 899.2 | 1,479.8 |
| Asset retirement obligations | 213.1 | 204.9 |
| Fair value of derivative contracts | 19.4 | 4.0 |
| Other long-term liabilities | 117.9 | 105.3 |
| Commitments and contingencies | | |
| **EQUITY** | | |
| Common stock – par value $0.01 per share; 500.0 million shares authorized; 240.7 million and 177.3 million shares issued, respectively | 2.4 | 1.8 |
| Treasury stock – 1.1 million and 0.5 million shares, respectively | (22.2) | (14.6) |
| Additional paid-in capital | 1,359.8 | 554.8 |
| Retained earnings | 2,306.6 | 3,418.3 |
| Accumulated other comprehensive income | (11.5) | (12.4) |
| Total Common Shareholders' Equity | 3,635.1 | 3,947.9 |
| TOTAL LIABILITIES AND EQUITY | $ 7,275.2 | $ 8,398.2 |

**QEP RESOURCES, INC.**
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(Unaudited)**

| | Nine Months Ended September 30, | |
|---|---|---|
| | **2016** | 2015 |
| | (in millions) | |
| **OPERATING ACTIVITIES** | | |
| Net income (loss) | **$ (1,111.7)** | $ (110.8) |
| Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities: | | |
| Depreciation, depletion and amortization | **667.5** | 649.3 |
| Deferred income taxes | **(581.1)** | 22.7 |
| Impairment | **1,188.2** | 35.5 |
| Bargain purchase gain from acquisition | **(4.4)** | — |
| Share-based compensation | **29.0** | 23.3 |
| Pension curtailment loss | **—** | 11.2 |
| Amortization of debt issuance costs and discounts | **4.8** | 4.7 |
| Net (gain) loss from asset sales | **(5.0)** | (6.9) |
| Unrealized (gains) losses on marketable securities | **(1.2)** | — |
| Unrealized (gains) losses on derivative contracts | **218.6** | 148.0 |
| Changes in operating assets and liabilities | **128.2** | (503.1) |
| Net Cash Provided by (Used in) Operating Activities | **532.9** | 273.9 |
| **INVESTING ACTIVITIES** | | |
| Property acquisitions | **(39.9)** | (23.5) |
| Acquisition deposit held in escrow | **(30.0)** | — |
| Property, plant and equipment, including dry exploratory well expense | **(411.2)** | (862.6) |
| Proceeds from disposition of assets | **28.9** | 5.2 |
| Net Cash Provided by (Used in) Investing Activities | **(452.2)** | (880.9) |
| **FINANCING ACTIVITIES** | | |
| Checks outstanding in excess of cash balances | **(25.5)** | (41.9) |
| Repayment of senior notes | **(176.8)** | — |
| Treasury stock repurchases | **(4.1)** | (2.3) |
| Other capital contributions | **—** | (0.1) |
| Dividends paid | **—** | (10.6) |
| Proceeds from issuance of common stock, net | **781.6** | — |
| Excess tax (provision) benefit on share-based compensation | **0.2** | (2.4) |
| Net Cash Provided by (Used in) Financing Activities | **575.4** | (57.3) |
| Change in cash and cash equivalents | **656.1** | (664.3) |
| Beginning cash and cash equivalents | **376.1** | 1,160.1 |
| Ending cash and cash equivalents | **$ 1,032.2** | $ 495.8 |

| | Production by Region | | | | | |
|---|---|---|---|---|---|---|
| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
| | **2016** | 2015 | Change | **2016** | 2015 | Change |
| | (in Bcfe) | | | | | |
| **Northern Region** | | | | | | |
| Pinedale | **24.0** | 26.3 | (9)% | **72.0** | 73.0 | (1)% |
| Williston Basin | **31.5** | 29.8 | 6 % | **92.5** | 83.8 | 10 % |
| Uinta Basin | **7.3** | 8.8 | (17)% | **22.5** | 23.0 | (2)% |
| Other Northern | **2.5** | 2.7 | (7)% | **6.9** | 7.8 | (12)% |
| Total Northern Region | **65.3** | 67.6 | (3)% | **193.9** | 187.6 | 3 % |
| **Southern Region** | | | | | | |
| Haynesville/Cotton Valley | **12.2** | 11.2 | 9 % | **30.5** | 33.3 | (8)% |
| Permian Basin | **9.0** | 7.3 | 23 % | **27.6** | 18.4 | 50 % |
| Other Southern | **0.1** | 0.6 | (83)% | **0.6** | 3.5 | (83)% |
| Total Southern Region | **21.3** | 19.1 | 12 % | **58.7** | 55.2 | 6 % |
| Total production | **86.6** | 86.7 | — % | **252.6** | 242.8 | 4 % |

| | Total Production | | | | | |
|---|---|---|---|---|---|---|
| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
| | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Gas (Bcf) | **46.8** | 48.0 | (3)% | **133.1** | 135.1 | (1)% |
| Oil (Mbbl) | **5,025.1** | 5,162.1 | (3)% | **15,411.0** | 14,519.4 | 6 % |
| NGL (Mbbl) | **1,616.5** | 1,286.9 | 26 % | **4,502.8** | 3,432.3 | 31 % |
| Total production (Bcfe) | **86.6** | 86.7 | — % | **252.6** | 242.8 | 4 % |
| Average daily production (MMcfe) | **941.3** | 942.4 | — % | **921.9** | 889.4 | 4 % |

| | Prices | | | | | |
|---|---|---|---|---|---|---|
| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
| | **2016** | 2015 | Change | **2016** | 2015 | Change |
| ***Gas (per Mcf)*** | | | | | | |
| Average field-level price | **$ 2.63** | $ 2.69 | | **$ 2.16** | $ 2.69 | |
| Commodity derivative impact | **0.01** | 0.48 | | **0.38** | 0.51 | |
| Net realized price | **$ 2.64** | $ 3.17 | (17)% | **$ 2.54** | $ 3.20 | (21)% |
| ***Oil (per bbl)*** | | | | | | |
| Average field-level price | **$ 40.12** | $ 41.01 | | **$ 35.89** | $ 44.13 | |
| Commodity derivative impact | **3.81** | 18.75 | | **5.18** | 16.90 | |
| Net realized price | **$ 43.93** | $ 59.76 | (26)% | **$ 41.07** | $ 61.03 | (33)% |
| ***NGL (per bbl)*** | | | | | | |
| Average field-level price | **$ 12.26** | $ 12.85 | | **$ 12.49** | $ 17.93 | |
| Commodity derivative impact | **—** | — | | **—** | — | |
| Net realized price | **$ 12.26** | $ 12.85 | (5)% | **$ 12.49** | $ 17.93 | (30)% |
| ***Average net equivalent price (per Mcfe)*** | | | | | | |
| Average field-level price | **$ 3.98** | $ 4.12 | | **$ 3.55** | $ 4.39 | |
| Commodity derivative impact | **0.22** | 1.38 | | **0.52** | 1.29 | |
| Net realized price | **$ 4.20** | $ 5.50 | (24)% | **$ 4.07** | $ 5.68 | (28)% |

| | Operating Expenses | | | | | |
|---|---|---|---|---|---|---|
| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
| | **2016** | 2015 | Change | **2016** | 2015 | Change |
| | (per Mcfe) | | | | | |
| Lease operating expense | **$ 0.58** | $ 0.65 | (11)% | **$ 0.65** | $ 0.72 | (10)% |
| Gas, oil and NGL transport & other handling costs | **0.87** | 0.90 | (3)% | **0.87** | 0.89 | (2)% |
| Production and property taxes | **0.31** | 0.35 | (11)% | **0.26** | 0.37 | (30)% |
| Total production costs | **$ 1.76** | $ 1.90 | (7)% | **$ 1.78** | $ 1.98 | (10)% |

**QEP RESOURCES, INC.**
**NON-GAAP MEASURES**
**(Unaudited)**

**Adjusted EBITDA**

This release contains references to the non-GAAP measure of Adjusted EBITDA. Management defines Adjusted EBITDA as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA) adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment and certain other items. Management believes Adjusted EBITDA is an important measure of the Company's financial and operating performance that allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. The following tables reconcile net income to Adjusted EBITDA:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| | (in millions) | | | |
| Net income (loss) | **$ (50.9)** | $ 21.1 | **$ (1,111.7)** | $ (110.8) |
| Interest expense | **35.9** | 36.4 | **109.2** | 109.4 |
| Interest and other (income) expense | **(5.1)** | (0.3) | **(7.1)** | (1.5) |
| Income tax provision (benefit) | **(29.0)** | 8.7 | **(641.2)** | (61.6) |
| Depreciation, depletion and amortization | **217.8** | 238.1 | **667.5** | 649.3 |
| Unrealized (gains) losses on derivative contracts | **(24.9)** | (33.8) | **218.6** | 148.0 |
| Exploration expenses | **0.2** | 0.8 | **0.9** | 2.7 |
| Net (gain) loss from asset sales | **(5.3)** | (12.9) | **(5.0)** | (6.9) |
| Impairment | **5.0** | 15.0 | **1,188.2** | 35.5 |
| Other [(1)] | **25.0** | — | **32.7** | 11.2 |
| Adjusted EBITDA | **$ 168.7** | $ 273.1 | **$ 452.1** | $ 775.3 |

(1) Reflects legal expenses and loss contingencies incurred during the three and nine months ended September 30, 2016, and a non-cash pension curtailment loss that was incurred during the nine months ended September 30, 2015, due to changes in the Company's pension plan. The Company believes that these losses do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the losses from the calculation of Adjusted EBITDA.

**Adjusted Net Income (Loss)**

This release also contains references to the non-GAAP measure of Adjusted Net Income (Loss). Management defines Adjusted Net Income (Loss) as earnings excluding gains and losses from asset sales, unrealized gains and losses on derivative contracts, asset impairments and certain other items. Management believes Adjusted Net Income (Loss) is useful to investors in assessing the Company's operational performance relative to other gas and oil producing companies.

The following table reconciles net income (loss) to Adjusted Net Income (Loss):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | 2015 | **2016** | 2015 |
| | (in millions, except earnings per share) | | | |
| Net income (loss) | **$ (50.9)** | $ 21.1 | **$ (1,111.7)** | $ (110.8) |
| Adjustments to net income (loss) | | | | |
| Unrealized (gains) losses on derivative contracts | **(24.9)** | (33.8) | **218.6** | 148.0 |
| Income taxes on unrealized (gains) losses on derivative contracts | **9.1** | 12.4 | **(80.0)** | (54.2) |
| Net (gain) loss from asset sales | **(5.3)** | (12.9) | **(5.0)** | (6.9) |
| Income taxes on net (gain) loss from asset sales | **1.9** | 4.7 | **1.8** | 2.5 |
| Impairment | **5.0** | 15.0 | **1,188.2** | 35.5 |
| Income taxes on impairment | **(1.8)** | (5.5) | **(434.9)** | (13.0) |
| Other (1) | **25.0** | — | **32.7** | 11.2 |
| Income taxes on other | **(9.2)** | — | **(12.0)** | (4.1) |
| Total after tax adjustments to net income | **(0.2)** | (20.1) | **909.4** | 119.0 |
| Adjusted Net Income (Loss) | **$ (51.1)** | $ 1.0 | **$ (202.3)** | $ 8.2 |
| | | | | |
| Earnings (Loss) per Common Share | | | | |
| Diluted earnings per share | **$ (0.21)** | $ 0.12 | **$ (5.15)** | $ (0.63) |
| Diluted after-tax adjustments to net income (loss) per share | **—** | (0.11) | **4.22** | 0.67 |
| Diluted Adjusted Net Income per share | **$ (0.21)** | $ 0.01 | **$ (0.93)** | $ 0.04 |
| | | | | |
| Weighted-average common shares outstanding | | | | |
| Diluted | **239.6** | 176.7 | **215.7** | 176.5 |

(1) Reflects legal expenses and loss contingencies incurred during the three and nine months ended September 30, 2016, and a non-cash pension curtailment loss that was incurred during the nine months ended September 30, 2015, due to changes in the Company's pension plan. The Company believes that these losses do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the losses from the calculation of Adjusted EBITDA.

The following tables present QEP's volumes and average prices for its open derivative positions as of October 21, 2016:

**Production Commodity Derivative Swap Positions**

| Year | Index | Total Volumes | | Average Swap Price per Unit |
|---|---|---|---|---|
| | | (in millions) | | |
| **Gas sales** | | (MMBtu) | | ($/MMBtu) |
| 2016 | NYMEX HH | 12.8 | $ | 2.90 |
| 2016 | IFNPCR | 12.2 | $ | 2.53 |
| 2017 | NYMEX HH | 87.6 | $ | 2.83 |
| 2017 | IFNPCR | 32.9 | $ | 2.51 |
| 2018 | NYMEX HH | 40.2 | $ | 2.94 |
| **Oil sales** | | (bbls) | | ($/bbl) |
| 2016 | NYMEX WTI | 3.4 | $ | 51.21 |
| 2017 | NYMEX WTI | 11.7 | $ | 50.88 |
| 2018 | NYMEX WTI | 6.6 | $ | 53.14 |

**Production Gas Collars**

| Year | Index | Total Volumes | | Average Price Floor | | Average Price Ceiling |
|---|---|---|---|---|---|---|
| | | (in millions) | | | | |
| | | (MMBtu) | | ($/MMBtu) | | ($/MMBtu) |
| 2016 | NYMEX HH | 1.2 | $ | 2.75 | $ | 3.89 |
| 2017 | NYMEX HH | 11.0 | $ | 2.50 | $ | 3.50 |

**Production Gas Basis Swaps**

| Year | Index Less Differential | Index | Total Volumes | | Weighted-Average Differential |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| **Gas sales** | | | (MMBtu) | | ($/MMBtu) |
| 2016 | NYMEX HH | IFNPCR | 6.1 | $ | (0.16) |
| 2017 | NYMEX HH | IFNPCR | 51.1 | $ | (0.18) |
| 2018 | NYMEX HH | IFNPCR | 7.3 | $ | (0.16) |
| **Oil sales** | | | (bbls) | | ($/bbl) |
| 2017 | NYMEX WTI | Argus WTI Midland [1] | 0.7 | $ | (0.75) |
| 2018 | NYMEX WTI | Argus WTI Midland [1] | 0.7 | $ | (0.95) |

(1) **Argus WTI Midland** is an index price reflecting the weighted average price of WTI at the pipeline and storage hub at Midland, Texas.

**Storage Commodity Derivative Positions**

| Year | Type of Contract | Index | Total Volumes | Average Swap Price per Unit | |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| **Gas sales** | | | (MMBtu) | | ($/MMBtu) |
| 2016 | SWAP | IFNPCR | 1.8 | $ | 2.85 |
| 2017 | SWAP | IFNPCR | 4.0 | $ | 2.88 |
| **Gas purchases** | | | | | |
| 2016 | SWAP | IFNPCR | 0.9 | $ | 2.58 |