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

# FORM 8-K/A

**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 28, 2017**

## DIAMONDBACK ENERGY, INC.
(Exact Name of Registrant as Specified in Charter)

| | | |
|---|---|---|
| **Delaware** | **001-35700** | **45-4502447** |
| (State or other jurisdiction of incorporation) | (Commission File Number) | (I.R.S. Employer Identification Number) |
| **500 West Texas**<br>**Suite 1200**<br>**Midland, Texas** | | **79701** |
| (Address of principal executive offices) | | (Zip code) |

**(432) 221-7400**
(Registrant’s telephone number, including area code)

**Not Applicable**
(Former name or former address, if changed since last report)

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

Emerging growth company o

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

Check the appropriate box below if the Form 8-K is intended to simultaneously satisfy the filing obligation of the Registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act
o Soliciting material pursuant to Rule 14a-12 under the Exchange Act
o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act
o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act

**Item 2.01. Completion of Acquisition or Disposition of Assets.**

As previously reported by Diamondback Energy, Inc. ("Diamondback") in its Current Report on Form 8-K filed on March 6, 2017, Diamondback acquired certain oil and natural gas properties, midstream assets and other related assets in the Delaware Basin (the "Acquisition") from Brigham Resources Operating, LLC. Diamondback hereby amends the initial report to provide the audited financial statements and pro forma financial information contemplated by Item 9.01(a) and (b) of Form 8-K in connection with the Acquisition.

**Item 9.01. Financial Statements and Exhibits**

*(a) Financial Statements of Business Acquired.*

The audited consolidated and combined balance sheets as of December 31, 2016, 2015 and 2014 and the related consolidated and combined statements of operations, statements of members' equity and statements of cash flows of Brigham Resources Operating, LLC for each of the three years ended December 31, 2016 and the related notes thereto, are attached hereto as Exhibit 99.1.

*(b) Pro Forma Financial Information*.

The unaudited pro forma condensed combined balance sheet of the Company as of December 31, 2016, which gives effect to the Acquisition as if it had occurred on December 31, 2016, and the unaudited pro forma condensed combined statement of operations for the year ended December 31, 2016 and the related notes thereto, which gives effect to the Acquisition as if it had occurred on January 1, 2016, are attached hereto as Exhibit 99.2.

*(d) Exhibits*.

| Exhibit Number | Description |
|---|---|
| 23.1 | Consent of KPMG LLP, Independent Auditors for Brigham Resources Operating, LLC. |
| 99.1 | Audited consolidated and combined balance sheets as of December 31, 2016, 2015 and 2014 and the related consolidated and combined statements of operations, statements of members' equity and statements of cash flows of Brigham Resources Operating, LLC for each of the three years ended December 31, 2016 and the related notes thereto. |
| 99.2 | Unaudited pro forma condensed combined balance sheet of the Company as of December 31, 2016, which gives effect to the Acquisition as if it had occurred on December 31, 2016, and the unaudited pro forma condensed combined statement of operations for the year ended December 31, 2016 and the related notes thereto, which gives effect to the Acquisition as if it had occurred on January 1, 2016. |

## SIGNATURE

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 thereunto duly authorized.

DIAMONDBACK ENERGY, INC.

Date: May 3, 2017

| | |
|---|---|
| By: | /s/ Teresa L. Dick |
| Name: | Teresa L. Dick |
| Title: | Chief Financial Officer, Executive Vice President and Assistant Secretary |

## Exhibit Index

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**Exhibit 23.1**

**Consent of Independent Auditors**

The Board of Directors
Brigham Resources Operating, LLC:

We consent to the incorporation by reference in the registration statements No. 333-217479 on Form S-4, No. 333-214892 on Form S-3ASR, No. 333-188552 on Form S-8, and No. 333-215798 on Form S-8 of Diamondback Energy, Inc. of our report dated March 31, 2017, with respect to the consolidated and combined balance sheets of Brigham Resources Operating, LLC as of December 31, 2016, 2015, and 2014, and the related consolidated and combined statements of operations, members' equity, and cash flows for each of the years then ended, which report appears in the Form 8-K/A of Diamondback Energy, Inc. filed May 3, 2017.

/s/ KPMG LLP

Dallas, Texas
May 3, 2017

# BRIGHAM RESOURCES OPERATING, LLC

# FINANCIAL STATEMENTS

# DECEMBER 31, 2016

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# Independent Auditors' Report

The Board of Directors
Brigham Resources Operating, LLC:

**Report on the Financial Statements**

We have audited the accompanying consolidated and combined financial statements of Brigham Resources Operating, LLC, which comprise the consolidated and combined balance sheets as of December 31, 2016, 2015, and 2014, and the related statements of operations, changes in members' equity, and cash flows for the years then ended, and the related notes to the consolidated and combined financial statements.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation and fair presentation of these consolidated and combined financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated and combined financial statements that are free from material misstatement, whether due to fraud or error.

*Auditors' Responsibility*

Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated and combined financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated and combined financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated and combined financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated and combined financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated and combined financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

*Opinion*

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of Brigham Resources Operating, LLC. as of December 31, 2016, 2015, and 2014, and the results of their operations and their cash flows for the years then ended in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP
Dallas, Texas
March 31, 2017

**Brigham Resources Operating, LLC**

**Consolidated and Combined Balance Sheets**

**December 31, 2016, 2015 and 2014**

| | December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Assets** | | | |
| Current assets: | | | |
| Cash and cash equivalents | $ 4,773,997 | $ 7,983,914 | $ 1,473,449 |
| Accounts receivable: | | | |
| Oil and gas sales | 8,803,549 | 4,568,262 | 2,970,661 |
| Joint interest billings | 4,038,447 | 16,381,441 | 15,092,048 |
| Other | 43,200 | — | 84,057 |
| Prepaid expenses and other | 3,451,993 | 149,060 | 116,482 |
| Inventory of oil field equipment, at cost | 409,916 | 4,241,657 | 2,524,475 |
| Derivative instruments | 6,758 | — | — |
| Total current assets | 21,527,860 | 33,324,334 | 22,261,172 |
| Oil and natural gas properties, at cost, using full cost method of accounting: | | | |
| Unevaluated property | 184,094,467 | 147,499,344 | 193,739,556 |
| Evaluated property | 640,690,043 | 463,032,228 | 253,464,157 |
| Wells in progress | 29,505,117 | 21,246,571 | 28,086,142 |
| | 854,289,627 | 631,778,143 | 475,289,855 |
| Less accumulated depletion, depreciation, and amortization | (439,314,183) | (207,881,700) | (12,511,638) |
| | 414,975,444 | 423,896,443 | 462,778,217 |
| Property and equipment | 1,008,045 | 693,306 | 151,351 |
| Less accumulated depreciation | (100,119) | (34,313) | (6,344) |
| | 907,926 | 658,993 | 145,007 |
| Midstream assets | 43,037,295 | 27,330,775 | — |
| Less accumulated depreciation | (2,324,859) | (616,545) | — |
| | 40,712,436 | 26,714,230 | — |
| Other assets, net | 1,245,403 | 451,982 | 424,914 |
| Total assets | $ 479,369,069 | $ 485,045,982 | $ 485,609,310 |
| **Liabilities and Member's Equity** | | | |
| Current liabilities: | | | |
| Accounts payable and accrued liabilities | $ 39,484,425 | $ 33,639,609 | $ 57,214,537 |
| Oil and gas revenue distributions payable | 7,292,125 | 7,156,469 | 3,184,537 |
| Derivative instruments | 10,113,420 | — | — |
| Total current liabilities | 56,889,970 | 40,796,078 | 60,399,074 |
| Long-term bank debt | 120,000,000 | 50,000,000 | 20,000,000 |
| Asset retirement obligation | 3,859,164 | 3,018,732 | 1,974,479 |
| Deferred tax liability | 133,505 | 625,202 | 1,240,281 |
| Derivative instruments | 2,615,274 | — | — |
| Member's equity: | | | |
| Member's equity | 636,210,765 | 551,880,976 | 400,787,169 |
| Accumulated earnings (deficit) | (340,339,609) | (161,275,006) | 1,208,307 |
| Total member's equity | 295,871,156 | 390,605,970 | 401,995,476 |
| Total liabilities and member's equity | $ 479,369,069 | $ 485,045,982 | $ 485,609,310 |

See accompanying notes to consolidated and combined financial statements.

**Brigham Resources Operating, LLC**

**Consolidated and Combined Statements of Operations**

**Years Ended December 31, 2016, 2015 and 2014**

| | December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| **Revenues:** | | | |
| Oil sales | $ 90,137,688 | $ 55,945,293 | $ 27,665,153 |
| Natural gas sales | 2,725,474 | 1,537,797 | 662,886 |
| Natural gas liquid sales | 3,488,145 | 1,662,984 | 1,061,854 |
| Rentals and saltwater disposal income | 2,116,557 | 332,984 | — |
| Total revenues | 98,467,864 | 59,479,058 | 29,389,893 |
| **Expenses:** | | | |
| Lease operating expenses | 17,755,616 | 16,992,595 | 5,688,574 |
| Severance and ad valorem taxes | 5,821,157 | 3,360,552 | 1,511,502 |
| Depreciation, depletion and amortization | 43,634,055 | 33,053,598 | 12,240,856 |
| Impairment of oil and natural gas properties | 189,826,617 | 163,083,373 | — |
| Impairment of field inventories | 500,751 | 437,600 | — |
| Bad debt expense | 343,793 | — | — |
| General and administrative expenses | 7,211,948 | 5,199,138 | 5,047,972 |
| Total operating expenses | 265,093,937 | 222,126,856 | 24,488,904 |
| **Net income (loss) from operations** | (166,626,073) | (162,647,798) | 4,900,989 |
| Loss on derivative instruments, net | (12,031,211) | — | — |
| Interest expense, net | (399,177) | (162,320) | (29,098) |
| Other income (loss), net | (499,839) | (288,275) | (379,967) |
| Income (loss) before income taxes | (179,556,300) | (163,098,393) | 4,491,924 |
| Income tax expense (benefit) | (491,697) | (615,080) | 1,240,281 |
| **Net income (loss)** | $ (179,064,603) | $ (162,483,313) | $ 3,251,643 |

See accompanying notes to consolidated and combined financial statements.

**Brigham Resources Operating, LLC**

**Consolidated and Combined Statements of Members' Equity**

**Years Ended December 31, 2106, 2015 and 2014**

| | | |
|---|---|---|
| Balance December 31, 2013 | $ | 223,835,319 |
| Contributions | | 175,119,318 |
| Other | | (210,805) |
| Net Income | | 3,251,643 |
| Balance December 31, 2014 | | 401,995,475 |
| Contributions | | 151,312,486 |
| Other | | (218,679) |
| Net loss | | (162,483,313) |
| Balance December 31, 2015 | | 390,605,969 |
| Contributions | | 86,055,102 |
| Other | | (1,725,312) |
| Net loss | | (179,064,603) |
| Balance December 31, 2016 | $ | 295,871,156 |

See accompanying notes to consolidated and combined financial statements.

**Brigham Resources Operating, LLC**

**Consolidated and Combined Statements of Cash Flows**

**Years Ended December 31, 2016, 2015 and 2014**

| | December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Cash flows from operating activities: | | | |
| Net income (loss) | $ (179,064,603) | $ (162,483,313) | $ 3,251,643 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation, depletion, and amortization | 43,379,986 | 32,931,203 | 12,178,957 |
| Impairment of oil and gas properties | 189,826,617 | 163,083,373 | — |
| Impairment of inventory | 500,751 | 437,600 | — |
| Provision for losses on accounts receivable | 343,793 | — | — |
| Deferred taxes | (491,697) | (615,080) | 1,240,281 |
| Asset retirement obligations | 254,069 | 122,395 | 61,900 |
| Settlements of asset retirement obligations | — | (69,260) | — |
| Loss on derivative instruments | 12,721,936 | — | — |
| Other, net | — | (3,450) | — |
| Amortization of debt closing costs | 213,048 | 111,861 | 14,297 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | 7,720,714 | (2,802,937) | (17,517,657) |
| Prepaid expenses | (3,302,933) | (32,578) | 95,683 |
| Accounts payable and accrued liabilities | (5,356,384) | (19,619,753) | 33,793,303 |
| Oil and gas revenue distributions payable | 135,654 | 3,971,933 | 3,078,051 |
| Net cash provided by operating activities | 66,880,951 | 15,031,994 | 36,196,458 |
| Cash flows from investing activities: | | | |
| Additions to oil and gas properties | (210,256,304) | (159,873,764) | (228,831,672) |
| Additions to field inventories | (588,858) | (4,924,568) | (2,524,475) |
| Additions to midstream assets | (12,254,289) | (24,136,120) | — |
| Additions to property and equipment | (314,738) | (541,955) | (151,351) |
| Net cash used in investing activities | (223,414,189) | (189,476,407) | (231,507,498) |
| Cash flows from financing activities: | | | |
| Repayment of long-term debt | (40,000,000) | (17,500,000) | (10,000,000) |
| Long-term debt advances | 110,000,000 | 47,500,000 | 30,000,000 |
| Long-term debt closing costs | (1,006,469) | (138,928) | (439,212) |
| Proceeds from unit issuance, net of offering costs | 84,329,790 | 151,093,806 | 174,908,514 |
| Related party note payable | — | — | 1,310,966 |
| Net cash provided by financing activities | 153,323,321 | 180,954,878 | 195,780,268 |
| Net decrease in cash and cash equivalents | (3,209,917) | 6,510,465 | 469,228 |
| Cash and cash equivalents: | | | |
| Beginning of period | 7,983,914 | 1,473,449 | 1,004,221 |
| End of period | $ 4,773,997 | $ 7,983,914 | $ 1,473,449 |
| | | | |
| Supplemental disclosure of noncash activity: | | | |
| Accrued capital expenditures | 31,897,731 | 18,352,233 | 22,370,044 |

See accompanying notes to consolidated and combined financial statements.

## (1) Organization and Business

Brigham Resources Operating, LLC (Brigham or the Company) was incorporated in the State of Texas on February 3, 2012 to pursue the acquisition, exploration, and development of onshore domestic oil and natural gas properties. On April 5, 2013, Brigham Resources, LLC (the Parent) acquired 100% of the common units of Brigham and Courage Oil and Gas, LLC (Courage). Courage was subsequently dissolved on April 30, 2014 and all assets and liabilities were transferred to Brigham Resources Operating, LLC at their carrying values at the date of the transfer. Brigham's exploration and development activities are focused in the Permian Basin.

Brigham Resources Midstream, LLC (the Midstream Company), a wholly owned subsidiary of Brigham Resources Operating, LLC, was incorporated in the State of Delaware on November 24, 2015. The Midstream Company owns and operates gathering pipelines, disposal and recycling facilities and compressor stations for the benefit of Brigham Resources Operating, LLC.

## (2) Significant Accounting Policies

### (a) Principles of Consolidation

Brigham is comprised of the combined financial statements of Brigham Resources Operating, LLC, and Courage Oil and Gas, LLC for 2014 and the consolidated financial statements of Brigham Resources Operating, LLC, and Brigham Resources Midstream, LLC for 2016 and 2015.

The combined and consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and include the accounts of Brigham and its wholly owned subsidiaries. All intercompany account balances have been eliminated in consolidation.

### (b) Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities in the consolidated financial statements and accompanying notes. Although management believes these estimates are reasonable, actual results could differ from these estimates. Changes in estimates are recorded prospectively. Significant assumptions are required in the valuation of proved oil and natural gas reserves which may affect the amount at which oil and natural gas properties are recorded. Estimation of asset retirement obligations (AROs) also requires significant assumptions. It is possible these estimates could be revised at future dates and these revisions could be material. Depletion of oil and natural gas properties are determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price estimates.

### (c) Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. Cash and cash equivalents are held in a few financial institutions in amounts that may, at times, exceed federally insured limits. However, no losses have been incurred and management believes that counterparty risks are minimal based on the reputation and history of the institutions selected.

### (d) Receivables

Receivables consist of: (i) receivables from exploration activities that reflect costs incurred on behalf of joint interest partners and (ii) receivables for production of estimated oil and natural gas revenues from third parties at the Company's net revenue interest. Receivables from third parties for which Brigham did not receive actual information, either due to timing delays or due to the unavailability of data at the time when revenues are recognized, are estimated. Volume estimates are based upon historical actual data if available, otherwise on engineering estimates. Pricing estimates are based upon actual prices recognized in an area by adjusting the strip price for the average differential from strip on a state-by-state basis.

The Company routinely reviews outstanding balances, assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. During 2016, the Company reserved $343,793 for doubtful accounts and recognized the same amount of bad debt expense due to an uncollectible receivable. The Company did not record any allowance for doubtful accounts for the years ended December 31, 2015 or 2014.

**(e) Concentration of Credit Risk and Significant Customers**

Financial instruments which potentially subject the Company to concentrations of credit risk consist of cash, accounts receivable and the credit facilities. Accounts receivable is concentrated among operators and purchasers engaged in the energy industry within the United States. Brigham periodically assesses the financial condition of these entities and institutions and considers any possible credit risk to be minimal. Concentrations of oil and gas sales to significant customers are presented in the table below.

| | December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| LPC Crude Oil Marketing, LLC | —% | —% | 63% |
| Plains Marketing L.P. | —% | 16% | 14% |
| BP Products North America | 21% | 22% | —% |
| Musket Corporation | 21% | 15% | —% |
| JP Energy Products Supply | —% | 13% | —% |
| Rio Energy International, Inc. | 15% | —% | —% |
| Trafigura Trading LLC | 14% | —% | —% |
| Vitol Inc | 13% | —% | —% |

Management does not believe that the loss of any customer would have a long-term material adverse effect on the Company's financial position or the results of operations as the commodities can be marketed to other purchasers.

**(f) Inventory**

Inventory includes tubular goods and other equipment that are utilized in the development of the Company's wells. Inventory is carried at the lower of cost or market and accounted for based on the average cost inventory cost flow assumptions. At December 31, 2016 and 2015 the book value of inventory exceeded the market value, accordingly, an inventory impairment was recognized in the amount of $500,751 and $437,600, respectively. The expensed amount is reflected in Impairment of field inventories in the operating expense section of the Statements of Operations. No impairment was recognized at December 31, 2014.

**(g) Oil and Gas Properties**

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition costs incurred for the purpose of acquiring mineral rights and all acquisition, exploration, and development costs incurred for the purpose of finding oil and natural gas, including certain related employee costs, are capitalized into a full cost pool. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, and other costs related to such activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Capitalized costs are amortized using the units-of-production method. Under this method, the provision for depletion is calculated by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the period.

Costs associated with unevaluated properties are excluded from the amortizable cost base until a determination has been made as to the existence of proved reserves. Unevaluated properties are reviewed periodically to determine whether the costs incurred should be reclassified to the full cost pool and subjected to amortization. The costs associated with unevaluated properties primarily consist of acquisition and leasehold costs. Unevaluated properties are assessed for impairment on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of various factors, including, but not limited to: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results, and economic viability of development if proved reserves are assigned. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. Wells in progress include development costs for uncompleted wells for which a determination of the existence of proved reserves has not been made. Costs associated with wells in progress are excluded from the amortizable base. These costs are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property, after production commences, upon impairment of a lease, or immediately upon determination that the well is unsuccessful. There was no impairment recorded for unevaluated properties or wells in progress in 2016, 2015 or 2014.

Sales and abandonments of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center.

Natural gas volumes are converted to barrels of oil equivalent (BOE) at the rate of six thousand cubic feet (Mcf) of natural gas to one barrel (Bbl) of oil. This convention is not an equivalent price basis and there may be a large difference in value between an equivalent volume of oil versus an equivalent volume of natural gas.

Under the full cost method of accounting, total capitalized costs of oil and natural gas properties, net of accumulated depletion, may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties (the ceiling limitation). A ceiling limitation is calculated at each reporting period. If total capitalized costs, net of accumulated depreciation, depletion and amortization (DD&A) are greater than the ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a noncash charge that reduces earnings and impacts equity in the period of occurrence and typically results in lower depletion expense in future periods. Once incurred, a write-down cannot be reversed at a later date. The ceiling limitation calculation is prepared using the 12 month first day of the month oil and natural gas average prices, as adjusted for basis or location differentials, held constant over the life of the reserves (net wellhead prices). If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of oil and natural gas. The future cash outflows associated with future development or abandonment of wells are included in the computation of the discounted present value of future net revenues for purposes of the ceiling limitation calculation.

As of December 31, 2016, 2015 and 2014, the full cost ceiling value of the Company’s reserves was calculated based on the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2016, 2015 and 2014 of $42.60, $50.00 and $95.28, respectively, per barrel for oil, adjusted by area for energy content, transportation fees, and regional price differentials and the unweighted arithmetic average first-day-of-the-month price for the 12-months ended December 31, 2016, 2015 and 2014 of $2.47, $2.62 and $4.36, respectively, per MMBtu for natural gas, adjusted by area for energy content, transportation fees, and regional price differentials. Using these prices, the Company’s net book value of oil and natural gas properties exceeded the ceiling limitation as of December 31, 2016 and 2015 and an impairment of $189,826,617 and $163,083,373 was recognized, respectively. No ceiling write off was necessary at December 31, 2014.

**(h) Midstream Assets**

Midstream Assets are gas and water gathering systems, disposal and recycling facilities and compressor stations. These assets are depreciated on a straight-line basis over the estimated useful lives of the assets. Estimated useful lives are as follows:

| | |
|---|---|
| Pipelines | 30 years |
| Saltwater disposal wells | 15 years |
| Produced water pond | 10 years |

Workovers and major improvements that extend the useful lives of these assets are capitalized while expenditures for wear and tear and regular maintenance are expensed as incurred.

**(i) Property and Equipment**

Property and equipment are stated at cost. Depreciation on property and equipment is calculated on the straight-line method over the estimated useful lives of the assets. Useful lives are generally determined to be five years except for assets that are related to contractual obligations in which case the remaining life of the contract is used. Property and equipment includes leasehold improvements incurred through the build-out of the Company’s corporate headquarters. Leasehold improvements are stated net of landlord allowances and are amortized over the lease term.

**(j) Income Taxes**

The Company is treated as a partnership for federal income tax purposes. As a result, the net taxable income of the Company and any related tax credits are passed through to the members and are included in their tax returns even though such net taxable income or tax credits may not have actually been distributed. Accordingly, no federal tax provision has been recorded in the Company's consolidated financial statements. The Company is subject to Texas margin tax based on revenue generated from operations within the state. The Company did not have any Texas margin tax due in 2016, 2015 or 2014. The Company had $133,505, $625,202 and $1,240,281 recorded as deferred tax liability related to the Texas margin tax at December 31, 2016, 2015 and 2014, respectively.

**(k) Asset Retirement Obligations**

The Company applies the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 410-20, Asset Retirement and Environmental Obligations-Asset Retirement Obligations, to account for estimated future plugging and abandonment costs. ASC 410-20 requires legal obligations associated with the retirement of long-lived assets to be recognized at their estimated fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. Brigham's asset retirement obligations primarily represent the present value of the estimated amount the Company will incur to plug, abandon, and remediate its proved producing properties and midstream assets at the end of their productive lives, in accordance with applicable state laws.

**(l) Revenue Recognition**

The Company recognizes revenues from the sale of oil and natural gas according to U.S. GAAP requirements. For the sale of natural gas, the Company uses the entitlements method of accounting. Under this method, revenue is recorded based on the Company's net working interest in the natural gas produced. Deliveries of natural gas in excess of the Company's working interest are recorded as liabilities while under deliveries are recorded as receivables. At December 31, 2016, 2015 and 2014, there were no gas imbalances.

**(m) Debt Issuance Cost**

Other assets include capitalized debt issuance costs of $1,245,403, $451,982 and $424,914, net of accumulated amortization of $339,206, $126,158 and $14,297 as of December 31, 2016, 2015 and 2014, respectively. Debt issuance costs were incurred in connection with establishing and amending credit facilities for Brigham Resources Operating (see note 6) and are amortized over the term of the credit facilities using the straight-line method, which approximates the effective interest rate method.

**(n) Derivatives**

Brigham uses derivative financial instruments to reduce exposure to fluctuations in commodity prices. These transactions are in the form of swaps, collars and basis swaps. Brigham reports the fair value of derivatives on the balance sheet in derivative instrument assets and liabilities, as applicable, and as either current or noncurrent, based on the timing of expected cash flows of individual trades. We include all derivative settlements and unrealized gains (losses) within the other income section of the Statement of Operations. Gains and losses from derivatives are included in cash flows from operating activities. Brigham's derivative instruments were not designated as cash flow hedges for accounting purposes under Financial Accounting Standards Board Accounting Standards Codification Topic 815 Derivatives and Hedging (FASB ASC 815).

**(o) Capitalized Interest**

Brigham capitalizes interest incurred on outstanding debt used to finance the acquisition, exploration, and development of oil and gas properties. Capitalized interest for the years ended December 31, 2016, 2015 and 2014 was $3,021,899, $1,133,425 and $94,217, respectively.

**(p) Fair Value Measurements**

The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. The following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels in accordance with Accounting Standards Update (ASU) 2011-04 (see note 11):

- Level 1 inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.

- Level 2 inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.

- Level 3 inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

**(q) Recently Issued Accounting Standards**

In January, 2017, the FASB issued Accounting Standards Update (“ASU”) No. 2017 - 01 to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This amendment will be effective for public business entities for annual periods beginning after December 15, 2017, including interim periods within those periods. All other entities should apply the amendments to annual periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019. We are evaluating the impact, if any, that the adoption of this update will have on our consolidated financial statements and related disclosures.

In August 2016, the FASB issued Accounting Standards Update (“ASU”) No. 2016-15, Classification of Certain Cash Receipts and Cash Payments, which applies to all entities that are required to present a statement of cash flows. The ASU provides guidance on the eight specific cash flow issues. The amendments in the update are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. For all other entities, the amendments are effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019 Early adoption is permitted. We are evaluating the impact, if any, that the adoption of this update will have on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued Accounting Standards Update (“ASU”) No. 2016-09, Improvements to Employee Share-Based Payment Accounting, which includes provisions intended to simplify various aspects related to how share-based compensation payments are accounted for and presented in financial statements. This amendment will be effective prospectively for reporting periods beginning on or after December 15, 2016, and early adoption is permitted. We are evaluating the impact, if any, that the adoption of this update will have on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU No. 2016-02, Leases, which requires all leasing arrangements to be presented in the balance sheet as liabilities along with a corresponding asset. The ASU will replace most existing leases guidance in GAAP when it becomes effective. The new standard becomes effective for us on January 1, 2019. Although early application is permitted, we do not plan to early adopt the ASU. The standard requires the use of the modified retrospective transition method. We are evaluating the impact, if any, that the adoption of this update will have on our consolidated financial statements and related disclosures.

In August 2015, the FASB issued an update to these changes based on an announcement of the staff of the SEC. This change provides an exception to the April 2015 FASB changes allowing debt issuance costs related to line-of-credit arrangements to continue to be presented as an asset regardless of whether there are any outstanding borrowings under such arrangement. We early adopted these pronouncements effective January 1, 2015, which did not have a material impact on our consolidated financial statements as ASU 2015-15 is consistent with how we currently account for our debt issuance costs incurred related to our line-of-credit facilities.

In April 2015, the FASB issued ASU No. 2015-03, “Simplifying the Presentation of Debt Issuance Costs,” as part of its simplification initiative. ASU 2015-03 changes the presentation of debt issuance costs in financial statements. Under the ASU, an entity presents such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. Amortization of the costs is reported as interest expense.

Effective January 1, 2015, the Company adopted ASU No. 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. ASU 2014-08 changed the requirements for reporting discontinued operations. This ASU limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have a major effect on an entity's operations and financial results. The new standard is effective for any disposals of components of the Company in annual reporting periods beginning after December 15, 2014.

Effective January 1, 2015, we early adopted, on a prospective basis, ASU No. 2015-01, Income Statement-Extraordinary and Unusual Items. This ASU simplifies income statement presentation by eliminating the concept of extraordinary items. There was no impact to our consolidated and combined financial statements or disclosures from the adoption of this standard.

Effective January 1, 2015, we early adopted, on a prospective basis, ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"). This ASU requires that deferred tax liabilities and assets, along with any related valuation allowance, be classified as noncurrent on the balance sheet. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the amendments in ASU 2015-17. As ASU 2015-17 was adopted on a prospective basis, we did not retrospectively adjust prior periods

In August 2014, the FASB issued ASU No. 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This update requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity's ability to continue as a going concern within one year after the date that the entity's financial statements are issued, or within one year after the date the entity's financial statements are available to be issued, and to provide disclosures when certain criteria are met. This guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. Early application is permitted. We are currently evaluating the impact, if any, that the adoption of this update will have on its consolidated financial statements or disclosures.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. This guidance is to be applied using a full retrospective method or a modified retrospective method, as outlined in the guidance. In August 2015, the FASB deferred the effective date of the new revenue recognition standard by one year. The revenue recognition standard is now effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted but only for annual periods, and interim periods within those annual periods, beginning after December 15, 2016. We are evaluating the impact, if any, that the adoption of this update will have on our consolidated financial statements and related disclosures.

### (3) Oil and Gas Properties and Equipment

The net capitalized costs related to the Company's oil and gas properties were as follows:

| | December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| Oil and natural gas properties, at cost, using full cost method of accounting: | | | |
| Unevaluated property(1) | 184,094,467 | 147,499,344 | 193,739,556 |
| Evaluated property(2) | 640,690,043 | 463,032,228 | 253,464,157 |
| Wells in progress(3) | 29,505,117 | 21,246,571 | 28,086,142 |
| Total oil and gas properties, at costs(4) | 854,289,627 | 631,778,143 | 475,289,855 |
| Less accumulated depletion, depreciation, and amortization(5) | (439,314,183) | (207,881,700) | (12,511,638) |
| Total oil and gas properties, net | 414,975,444 | 423,896,443 | 462,778,217 |

(1) Unevaluated property includes acquisition and leasehold costs which are excluded from the amortization base. Unevaluated properties are assessed for impairment periodically. Costs are transferred into the evaluated basis and are subject to depletion once reserves are established or impairment determined. The Company has a development plan for all properties included in the unevaluated basis within the next five years, otherwise costs are transferred to the evaluated basis.

(2) Costs in the evaluated basis are subject to unit of production depletion.

(3) Costs in wells in progress are excluded from the amortization base until reserves are established or first production occurs, whichever is sooner.

(4) Total oil and gas properties, at cost, included capitalized interest of $4,249,541, $1,227,642 and $94,217 at December 31, 2016, 2015 and 2014, respectively.

(5) Accumulated depreciation, depletion and amortization includes depreciation, depletion and amortization expense, ARO accretion and ceiling impairment expense since inception.

Costs excluded from the amortizable base at December 31, 2016, 2015 and 2014 are categorized as follows:

| | Capitalized cost incurred in the year ended December 31, | | | | |
|---|---|---|---|---|---|
| | **2016** | **2015** | **2014** | **Prior** | **Since Inception** |
| Acquisition | 45,293,633 | 37,408,498 | 47,897,829 | 52,148,051 | 182,748,010 |
| Exploration | 50,464 | (13,960) | 187,766 | 19,967 | 24,234 |
| Development | 27,837,885 | 1,403,513 | 256,938 | 6,782 | 29,505,117 |
| Capitalized interest | 934,195 | 146,762 | 21,265 | — | 1,102,223 |
| Total | 74,116,177 | 38,944,813 | 48,363,798 | 52,174,800 | 213,379,584 |

Oil and natural gas properties are depleted on a unit of production basis. Depletion expense for the years ended December 31, 2016, 2015 and 2014 was $41,605,866, $32,286,689 and $12,172,613, respectively. Depreciation expense for equipment and the midstream assets is calculated on a straight line method. For the years ended December 31, 2016, 2015 and 2014 depreciation expense was $1,774,121, $644,514 and $6,344 respectively.

Brigham capitalizes certain overhead expenses and other internal costs attributable to acquisition, exploration, and development activities as part of its investment in oil and gas properties over the periods benefitted by these activities. Capitalized costs do not include any costs related to production and general corporate overhead, or similar activities. Capitalized costs for the years ended December 31, 2016, 2015 and 2014 were $2,279,964, $2,150,339 and $2,531,649, respectively.

**(4) Acquisitions and Divestitures**

During 2016, 2015 and 2014 the Company did not enter into any individually significant acquisition transactions. The change in the oil and natural gas property balance is comprised of individually insignificant lease bonus payments, land brokerage costs, capitalized general and administrative, and drilling capital expenditures.

On December 13, 2016, Brigham Resources Operating, LLC and Brigham Resources Midstream, LLC entered into a definitive agreement with an third party public entity to sell substantially all of its leasehold and royalty interests and related assets in the Delaware Basin for $1,618,589,633 in cash and 7,685,918 in shares of the buyer’s common stock, valued at $809,173, 428 for a total unadjusted sales price of $2,427,763,061.This transaction closed on February 28, 2017.

**(5) Asset Retirement Obligations**

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred, along with a corresponding increase in the carrying amount of the related long-lived asset. The following table summarizes the activities of the Company’s asset retirement obligations for the years ended December 31, 2016, 2015 and 2014:

| | **2016** | **2015** | **2014** |
|---|---|---|---|
| Asset retirement obligations: | | | |
| Balance beginning of period | $ 3,018,732 | $ 1,974,479 | $ 157,216 |
| AROs created during the year | 586,364 | 991,118 | 1,755,363 |
| Liabilities settled | — | (69,260) | — |
| Accretion expense | 254,068 | 122,395 | 61,900 |
| Balance end of period | $ 3,859,164 | $ 3,018,732 | $ 1,974,479 |

The Company has no assets that are legally restricted for purposes of settling asset retirement obligations. No settlements of asset retirement obligations occurred during the year ended December 31, 2016 and 2014.

## (6) Long-Term Bank Debt

### Brigham Resources Operating Credit Agreement

Brigham Resources Operating, LLC (the Borrower) maintains a secured revolving credit agreement with a syndicate of financial institutions, which has been amended periodically. The credit agreement provides for a $500 million revolving credit facility, subject to periodic borrowing base redeterminations based on the Borrower's oil and natural gas reserves and other factors (the borrowing base). The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1 and November 1. In addition, the Borrower may request up to one additional redetermination of the borrowing base during any fiscal year. The borrowing base and outstanding borrowings were $185 million and $120 million as of December 31, 2016, compared to $60 million and $50 million as of December 31, 2015 and $40 million and $20 million as of December 31, 2014.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company that is equal to either an alternative adjusted base rate, (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% or 3-month LIBOR plus 1.0%,) or 1-month an adjusted LIBOR rate with an interest period selected by the Company, in each case plus the applicable margin. The applicable margin ranges from 1.50% to 2.50% in the case of the alternative adjusted base rate and from 2.50% to 3.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Borrower is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, depending on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be repaid from time to time at the option of the Company without premium or penalty (other than customary LIBOR breakage). Loan principal is required to be paid back to the extent the loan amount exceeds the borrowing base at any time before maturity or the total outstanding balance upon the January 26, 2021 maturity date. The loan is secured by substantially all of the Borrower's assets.

The credit agreement contains various affirmative and negative covenants including limiting additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, and entering into certain swap agreements. Additionally, the credit agreement requires the maintenance of financial ratios including total debt to earnings before interest, taxes, depreciation, amortization and exploration expense (EBITDAX) not to exceed 4 to 1 on a quarterly basis beginning December 31, 2014 and a ratio of current assets to current liabilities of no less than 1 to 1 on a quarterly basis beginning March 31, 2015. At year end 2015, Borrower's current liabilities exceeded current assets; however as the covenant calculation allows for undrawn borrowings to cover any working capital deficiencies, the Company was in compliance with the current ratio and all other financial covenants as of December 31, 2015. The Company was in compliance with all financial covenants as of December 31, 2016 and 2014.

## (7) Drilling commitment

In connection with a certain acquisition on September 1, 2013, the Company entered into a drilling commitment for a $19,367,196 carried interest required to be satisfied within two years from the closing date or otherwise in cash. During 2015 all of this commitment was satisfied.

## (8) Commitments and Contingencies

### (a) Overhead Expense Sharing

Brigham has an overhead expense sharing arrangement provided for under a Management Services Agreement (the MSA) with Brigham Resources Management, LLC (the Management Company), an affiliated company. Under the MSA, the Management Company provides all general and administrative management and similar services to Brigham and other affiliates in return for applicable direct or indirect expense reimbursement plus an annual fee of the greater of 5% of the reimbursement or the subsidiaries' proportionate share of $50,000. For 2016, 2015 and 2014, the Company's annual fee to the Management Company was $473,674, $390,557 and $380,319, respectively.

**(b) Lease obligations**

The Company leases office space under operating leases. Rent expense for 2016, 2015 and 2014 was $414,711, $390,557 and $380,319, respectively. Future minimum lease commitments under noncancelable operating leases at December 31, 2016 are presented below:

| | | |
|---|---|---|
| Noncancelable operating lease obligations: | | |
| 2017 | $ | 646,918 |
| 2018 | | 620,842 |
| 2019 | | 607,814 |
| 2020 | | 168,393 |
| Thereafter | | — |
| Total | $ | 2,043,967 |

**(c) Litigation**

The Company may, from time to time, be a party to certain lawsuits and claims arising in the ordinary course of business. The outcome of such lawsuits and claims cannot be estimated with certainty and management may not be able to estimate the range of possible losses. The Company records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated. The Company was not involved in any litigation, claims, or other legal proceedings at December 31, 2016.

**(9) Related-Party Transactions**

Brigham Land Management (BLM) provides the Company with land brokerage services. BLM is owned by Vince Brigham, an advisor to the Company and brother of Bud Brigham, founder of the Company and Chairman of the Board. For the years ended December 31, 2016, 2015 and 2014 Brigham paid BLM $2,986,192, $2,097,868 and $4,154,865, respectively for land brokerage services. At December 31, 2016, 2015 and 2014, the Company had $410,862, $290,236 and $77,340, respectively, recorded as liabilities for services performed by BLM during the respective periods

**(10) Derivatives**

Brigham uses derivative financial instruments to reduce exposure to fluctuations in commodity prices. These transactions are in the form of swaps, collars and basis swaps. Brigham reports the fair value of derivatives on the balance sheet in derivative instrument assets and liabilities, as applicable, and as either current or noncurrent, based on the timing of expected cash flows of individual trades. We include all derivative settlements and unrealized gains (losses) within the other income section of the Statement of Operations. Gains and losses from derivatives are included in cash flows from operating activities. Brigham's derivative instruments were not designated as cash flow hedges for accounting purposes under Financial Accounting Standards Board Accounting Standards Codification Topic 815 Derivatives and Hedging (FASB ASC 815).

As of December 31, 2016, the Company had open crude oil and natural gas derivative positions with respect to future production as set forth in the table below.

**Oil Swaps**

| Production Period | Volume (Bbl) | Fixed Price Swap ($/Bbl) |
|---|---|---|
| January 2017-March2017 | 45,000 | 50.75 |
| January 201-June 2017 | 90,000 | 49.50 |
| January 2017-December 2017 | 180,000 | 44.42 |
| January 2017-December 2017 | 180,000 | 44.10 |
| January 2017-December 2017 | 180,000 | 46.25 |
| January 2017-December 2017 | 180,000 | 47.70 |
| January 2018-December 2018 | 180,000 | 53.75 |
| January 2017-December 2018 | 360,000 | 54.50 |
| January 2017-December 2018 | 360,000 | 51.50 |
| January 2018-December 2018 | 180,000 | 52.50 |

**Natural Gas Swap**

| Production Period | Volume (MMBTU) | Fixed Price Swap ($/MMBTU) |
|---|---|---|
| January 2017-December 2018 | 1,017,000 | 2.88 |

The following table summarizes the impact of derivative transactions on our income for the presented period.

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Cash settlement receipts (payments) for the period, net | 690,725 | — | — |
| Mark to market gains (losses) for the period, net | (12,721,936) | — | — |

***Credit Risk in Derivatives***

The Company considers and monitors the creditworthiness of its counterparties when entering into derivative contracts. The Company considers the credit risk of our counterparties minimal as contracts are only entered into with a large multinational financial institutions with investment grade credit rating. As of December 31, 2016 we have not incurred any losses due to counterparties' inability to perform under the contract.

**(11) Fair Value**

ASC Topic 820, *Fair Value Measurements and Disclosures*, defines fair value and provides a hierarchal framework associated with the level of subjectivity used in measuring assets and liabilities at fair value.

At December 31, 2016, 2015 and 2014, Brigham's financial instruments consist primarily of cash, trade and other receivables, trade payables, long-term bank debt and derivatives. The carrying value of cash, trade and other receivables, and trade payables are considered to be representative of their respective fair values due to the short-term nature of these instruments. The carrying amount of debt outstanding pursuant to the credit agreement approximates fair value as interest rates on these instruments approximate current market rates. Derivatives are not designated as cash flow hedges and are marked to fair value for accounting purposes. Brigham reports the fair value of derivatives on the balance sheet in derivative instrument assets and liabilities, as applicable, and as either current or noncurrent, based on the timing of expected cash flows of individual trades. Settlements and unrealized gains and losses are recorded on the consolidated statement of operations. The fair value of our derivative contracts are determined based on counterparties' estimates and valuation models, that is considered a Level 2 input.

The following summarizes the fair value of the Company's derivative assets and liabilities according to their fair value hierarchy as of the reporting dates indicated:

| | December 31, 2016 | | | December 31, 2015 | | | December 31, 2014 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Level 1 | Level 2 | Level 3 | Level 1 | Level 2 | Level 3 |
| Derivative assets | | | | | | | | | |
| Short term derivative assets | — | 6,758 | — | — | — | — | — | — | — |
| Long term derivative assets | — | — | — | — | — | — | — | — | — |
| Total derivative assets | — | 6,758 | — | — | — | — | — | — | — |
| Derivative liabilities | | | | | | | | | |
| Short term derivative liabilities | — | 10,113,420 | — | — | — | — | — | — | — |
| Long term derivative liabilities | — | 2,615,274 | — | — | — | — | — | — | — |
| Total derivative liabilities | — | 12,728,694 | — | — | — | — | — | — | — |

## (12) Employee Benefit Plans

In 2013, the Company adopted a defined-contribution 401(k) plan for its employees. The plan provides for Company matching of 100% of each employee's contributions, up to 6% of the employee's total compensation. The Company may also contribute additional amounts at its discretion. The Company contributed $256,743, $$280,561 and $173,815 to the 401(k) plan for the years ended December 31, 2016, 2015 and December 31, 2014, respectively.

## (14) Subsequent Events

The Company has evaluated subsequent events from the balance sheet date through March 31, 2017, the date at which the combined financial statements were available to be issued.

On February 28, 2017, the Company purchased a 5% ownership interest in Oryx Southern Delaware Holdings LLC for $9,387,695.

On February 28, 2017, the Company closed on the sale of substantially all of its Southern Delaware Basin leasehold, royalty interests and related assets to a third party public entity for $1,742,392,261 in cash and 7,685,918 in shares the buyer's common stock valued at $809,173,428 for an adjusted total sales price of $2,551,565,689. In connection with the sale of assets, the Company terminated its credit facility and repaid the outstanding balance plus accrued interest and fees totaling $135,478,392 and also paid $8,451,900 to settle all of its outstanding financial derivative positions.

On March 3, the Company made equity distributions in the amount of $1,397,062,284.

## (15) Reserves And Related Financial Data (SMOG)-Unaudited

The reserves at December 31, 2016, 2015 and 2014 presented below were prepared by Cawley, Gillespie & Associates, Inc. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. The primary location of the reserves is in Pecos and Reeves Counties in Texas. All of the proved reserves are located in the continental United States.

Guidelines prescribed in FASB's Accounting Standards Codification ("ASC") Topic 932 *Extractive Industries-Oil and Gas*, have been followed for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated quantities of oil, natural gas and NGL's to be produced in the future. The resulting future net cash flows are reduced to present value amounts by applying a ten percent annual discount factor. Future operating costs are determined based on estimates of expenditures to be incurred in producing the proved oil and gas reserves in place at the end of the period using year-end costs and assuming continuation of existing economic conditions, plus overhead incurred. Future development costs are determined based on estimates of capital expenditures to be incurred in developing proved oil and gas reserves.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. Reserve estimates are inherently imprecise and estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. The standardized measure excludes income taxes as the Company is a limited liability company and not subject to income taxes.

The following table sets forth information as of and for the years ended December 31, 2016, 2015 and 2014, with respect to changes in the proved reserves:

| | Crude Oil (MBbl) | Natural Gas (Mmcf) | NGLs (MBbl) | Total (MMBOE) |
|---|---|---|---|---|
| **January 1, 2014** | 817 | 582 | 97 | 1,011 |
| Extensions, discoveries and other additions | 9,691 | 8,725 | 2,013 | 13,158 |
| Acquisitions | — | — | — | — |
| Revisions | 312 | (43) | 14 | 319 |
| Production | (354) | (168) | (25) | (407) |
| **December 31, 2014** | 10,466 | 9,096 | 2,099 | 14,081 |
| Extensions, discoveries and other additions | 17,345 | 12,243 | 2,563 | 21,949 |
| Acquisitions | 2,697 | 2,259 | 461 | 3,535 |
| Revisions | 2,414 | 2,812 | 260 | 3,143 |
| Production | (1,292) | (642) | (128) | (1,527) |
| **December 31, 2015** | 31,630 | 25,768 | 5,255 | 41,180 |
| Extensions, discoveries and other additions | 11,253 | 7,710 | 1,882 | 14,420 |
| Acquisitions | 3,645 | 2,247 | 564 | 4,584 |
| Revisions | (10,955) | (11,157) | (1,778) | (14,593) |
| Production | (2,241) | (1,596) | (367) | (2,874) |
| **December 31, 2016** | 33,333 | 22,973 | 5,556 | 42,717 |
| | | | | |
| **Proved developed reserves, included above:** | | | | |
| December 31, 2014 | 3,889 | 3,123 | 721 | 5,131 |
| December 31, 2015 | 8,042 | 7,241 | 1,445 | 10,694 |
| December 31, 2016 | 12,198 | 9,866 | 2,272 | 16,114 |
| | | | | |
| **Proved undeveloped reserves, included above:** | | | | |
| December 31, 2014 | 6,577 | 5,973 | 1,378 | 8,951 |
| December 31, 2015 | 23,588 | 18,526 | 3,810 | 30,486 |
| December 31, 2016 | 21,134 | 13,107 | 3,285 | 26,604 |

The following table summarizes the Company’s proved undeveloped reserves activity during the period ended December 31, 2016.

| | PUD Reserves in MBOE |
|---|---|
| Beginning proved undeveloped reserves | 30,486 |
| Revisions of previous estimates | (15,172) |
| Extentions and discoveries | 9,999 |
| Purchase of minerals in place | 2,579 |
| Transfers to proved developed | (1,288) |
| Ending proved undeveloped reserves | 26,604 |

As of December 31, 2016, the reserves are comprised of 78.0% crude oil, 9.0% natural gas, and 13.0% of NGL on an energy equivalent basis. As of December 31, 2015, the reserves are comprised of 76.8% crude oil, 10.4% natural gas, and 12.8% of NGL on an energy equivalent basis. As of December 31, 2014, the reserves are comprised of 70.2% crude oil, 14.3% natural gas, and 15.6% of NGL on an energy equivalent basis. The following values for the 2016 proved reserves were derived based on prices of $42.60 per Bbl of crude oil and $2.47 per Mcf of natural gas. The following values for the 2015 proved reserves were derived based on prices of $50.00 per Bbl of crude oil and $2.62 per Mcf of natural gas. The following values for the 2014 proved reserves were derived based on prices of $95.28 per Bbl of crude oil, $4.36 per Mcf of natural gas, and $38.11 per Bbl of NGLs. These prices were based on the 12-month arithmetic average first-of-month price for January 2016 through December 2016, January 2015 through December 2015 and January 2014 through December 2014, respectively. The crude oil pricing was based on the West Texas Intermediate price; the natural gas pricing was based on the Henry Hub price; the NGL pricing was 40%, 30%, and 33% of WTI in 2014, 2015, and 2016, respectively. All prices have been adjusted for transportation, quality and basis differentials.

For the years ended December 31, 2016, 2015 and 2014, the Company added 14,420 and 21,949 MBoe and 13,158 MBoe of proved reserves through extensions, discoveries, or other additions due to our ongoing drilling program.

For the years ended December 31, 2016, 2015 and 2014, the Company added 4,584 and 3,535 MBoe and 0 MBoe of proved reserves through acquisitions of small non-operated working interests in our existing wells and leasing of open acreage in our existing leasehold prior to drilling a well.

For the year ended December 31, 2016, the Company had net negative revisions to proved reserves of 14,593 MBoe due to a decrease in commodity prices. For the year ended December 31, 2015, the Company had net positive revisions to proved reserves of 3,143 MBoe due to increased EURs from our improved completion methodology, partially offset by negative revisions due to a significant decrease in commodity prices. For the year ended December 31, 2014, the Company had positive revisions to proved reserves of 319 MBoe due to additional production and performance data.

The following summary sets forth the future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in ASC Topic 932 (in thousands):

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2016 | 2015 | 2014 |
| Future crude oil, natural gas, and NGLs sales | $ 1,422,689 | $ 1,609,302 | $ 1,052,355 |
| Future production costs | (486,050) | (490,617) | (279,089) |
| Future development costs | (428,316) | (452,445) | (168,827) |
| Future income tax expense | (7,469) | (8,449) | (7,366) |
| Future net cash flows | 500,854 | 657,791 | 597,072 |
| 10% discount to reflect timing of cash flows | (303,607) | (406,627) | (324,722) |
| Standardized measure of discounted future net cash flows | $ 197,247 | $ 251,164 | $ 272,350 |

Changes in the standardized measure of discounted future net cash flows relating to proved oil and gas reserves are as follows for the years ended December 31,:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | **2016** | **2015** | **2014** |
| Standardized measure of discounted future net cash flows, beginning of year | $ 251,164 | $ 272,350 | $ 18,986 |
| Changes in the year resulting from: | | | |
| Sales, less production costs | (76,627) | (39,607) | (22,190) |
| Revisions of previous quantity estimates | (35,341) | 31,340 | 7,841 |
| Extensions, discoveries and other additions | 52,373 | 133,717 | 252,722 |
| Net changes in prices and production costs | (52,722) | (209,730) | (3,162) |
| Changes is estimated future development costs | (20,339) | 7,420 | 1,968 |
| Previously estimated development costs incurred during the period | 35,749 | 1,281 | 7,444 |
| Accretion of discount | 25,515 | 27,587 | 1,899 |
| Purchase of reserves in place | 15,573 | 19,246 | — |
| Net change in income taxes | (142) | (465) | (3,272) |
| Timing differences and other | 2,043 | 8,024 | 10,115 |
| Standardized measure of discounted future net cash flows, end of year | $ 197,247 | $ 251,164 | $ 272,350 |

**Exhibit 99.2**

# UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

On February 28, 2017, Diamondback Energy, Inc. completed the acquisition of certain oil and natural gas properties, midstream assets and other related assets in the Delaware Basin (the "Acquisition") from Brigham Resources Operating, LLC ("Brigham"). The following unaudited pro forma condensed combined financial information and related notes are based on the historical financial statements of Diamondback Energy, Inc. and Subsidiaries (“Diamondback” or the “Company,” and also referred to as “we,” “us” or “our”) and Brigham, and have been prepared to give effect to the Acquisition.

The unaudited pro forma condensed combined statement of operations for the year ended December 31, 2016 presented below has been prepared based on Diamondback’s historical audited statement of operations for such period, and was prepared as if the Acquisition had occurred on January 1, 2016. The unaudited pro forma combined balance sheet at December 31, 2016 presented below was prepared based on Diamondback’s historical audited consolidated balance sheet at December 31, 2016, and was prepared as if the Acquisition had occurred on December 31, 2016.

The accompanying unaudited pro forma condensed combined financial statements are based on assumptions and include adjustments as explained in the notes thereto. Certain information (including substantial footnote disclosures) included in our annual historical financial statements has been excluded in these unaudited pro forma condensed combined financial statements. The unaudited pro forma condensed combined financial statements are not intended to represent or be indicative of the consolidated results of operations or financial position that we would have reported had the acquisitions been completed as of the dates presented, and should not be taken as representative of our future consolidated results of operations or financial condition.

The unaudited pro forma condensed combined financial statements should be read in conjunction with the historical consolidated financial statements and accompanying notes of Diamondback included in our Annual Report on Form 10-K for the year ended December 31, 2016 as well as Brigham’s audited historical financial statements and accompanying notes for the year ended December 31, 2016, included as Exhibit 99.1 in this Current Report on Form 8-K.

**Diamondback Energy, Inc. and Subsidiaries**
**Unaudited Pro Forma Condensed Combined Balance Sheet**
**As of December 31, 2016**

| | Diamondback | Brigham | Adjustments | | Pro Forma Adjustments | | Pro Forma Combined |
|---|---|---|---|---|---|---|---|
| | | | (In thousands) | | | | |
| **Assets** | | | | | | | |
| Current assets: | | | | | | | |
| Cash and cash equivalents | $ 1,666,574 | $ 4,774 | $ 1,637 | (a) | $ (1,627,415) | (b) | $ 45,570 |
| Restricted cash | 500 | — | — | | — | | 500 |
| Accounts receivable: | | | | | | | |
| Joint interest and other | 49,476 | 4,082 | — | | (4,082) | (b) | 49,476 |
| Oil and natural gas sales | 70,349 | 8,803 | — | | (8,803) | (b) | 70,349 |
| Related party | 297 | — | — | | — | | 297 |
| Inventories | 1,983 | 410 | — | | 429 | (b) | 2,822 |
| Derivative instruments | — | 7 | — | | (7) | (b) | — |
| Prepaid expenses and other | 2,987 | 3,452 | — | | 8 | (b) | 6,447 |
| Total current assets | 1,792,166 | 21,528 | 1,637 | | (1,639,870) | | 175,461 |
| Property and equipment: | | | | | | | |
| Oil and natural gas properties, at cost, full cost method of accounting | 5,160,261 | 854,290 | 5,485 | (a) | 1,651,017 | (b) | 7,671,053 |
| Pipeline and gas gathering assets | 8,362 | 43,037 | — | | 3,711 | (b) | 55,110 |
| Other property and equipment | 58,290 | 1,008 | — | | (1,008) | (b) | 58,290 |
| Accumulated depletion, depreciation, amortization and impairment | (1,836,056) | (441,739) | 45,026 | (a) | 396,713 | (b) | (1,836,056) |
| Net property and equipment | 3,390,857 | 456,596 | 50,511 | | 2,050,433 | | 5,948,397 |
| Funds held in escrow | 121,391 | — | — | | (121,388) | (b) | 3 |
| Derivative instruments | 709 | — | — | | — | | 709 |
| Other assets | 44,557 | 1,245 | — | | (1,245) | (b) | 44,557 |
| Total assets | $ 5,349,680 | $ 479,369 | $ 52,148 | | $ 287,930 | | $ 6,169,127 |
| **Liabilities and Stockholders' Equity** | | | | | | | |
| Current liabilities: | | | | | | | |
| Accounts payable-trade | $ 47,648 | $ 39,485 | $ — | | $ (39,485) | (b) | $ 47,648 |
| Accounts payable-related party | 1 | — | — | | — | | 1 |
| Accrued capital expenditures | 60,350 | — | — | | — | | 60,350 |
| Other accrued liabilities | 55,330 | | | | | | 55,330 |
| Revenue and royalties payable | 23,405 | 7,292 | — | | 1,431 | (b) | 32,128 |
| Derivative instruments | 22,608 | 10,113 | — | | (10,113) | (b) | 22,608 |
| Total current liabilities | 209,342 | 56,890 | — | | (48,167) | | 218,065 |
| Long-term debt | 1,105,912 | 120,000 | — | | (120,000) | (b) | 1,105,912 |
| Derivative instruments | — | 2,615 | — | | (2,615) | (b) | — |
| Asset retirement obligations | 16,134 | 3,859 | — | | (2,309) | (b) | 17,684 |
| Deferred income taxes | — | 134 | — | | (134) | (b) | — |
| Total liabilities | 1,331,388 | 183,498 | — | | (173,225) | | 1,341,661 |
| Commitments and contingencies | | | | | | | |
| Stockholders' equity: | | | | | | | |
| Common stock | 901 | — | — | | 77 | (b) | 978 |
| Additional paid-in capital | 4,215,955 | 636,211 | 5,378 | (a) | 167,508 | (b) | 5,025,052 |
| Accumulated deficit | (519,394) | (340,340) | 46,770 | (a) | 293,570 | (b) | (519,394) |
| Total Diamondback Energy, Inc. stockholders' equity | 3,697,462 | 295,871 | 52,148 | | 461,155 | | 4,506,636 |
| Non-controlling interest | 320,830 | — | — | | — | | 320,830 |
| Total equity | 4,018,292 | 295,871 | 52,148 | | 461,155 | | 4,827,466 |
| Total liabilities and equity | $ 5,349,680 | $ 479,369 | $ 52,148 | | $ 287,930 | | $ 6,169,127 |

**Diamondback Energy, Inc. and Subsidiaries**
**Unaudited Pro Forma Condensed Combined Statements of Operations**
**For the Year Ended December 31, 2016**

| | Diamondback | Brigham | Adjustments | | Pro Forma Adjustments | | Pro Forma Combined |
|---|---|---|---|---|---|---|---|
| **Revenues:** | | | | | | | |
| Oil sales | $ 470,528 | $ 90,138 | $ 1,646 | (a) | $ — | | $ 562,312 |
| Natural gas sales | 22,506 | 2,725 | 35 | (a) | — | | 25,266 |
| Natural gas liquid sales | 34,073 | 3,488 | 45 | (a) | — | | 37,606 |
| Midstream services | — | 2,117 | — | | — | | 2,117 |
| Total revenues | 527,107 | 98,468 | 1,726 | | — | | 627,301 |
| **Costs and expenses:** | | | | | | | |
| Lease operating expenses | 82,428 | 17,755 | (29) | (a) | — | | 100,154 |
| Production and ad valorem taxes | 34,456 | 5,821 | 89 | (a) | — | | 40,366 |
| Gathering and transportation | 11,606 | — | — | | — | | 11,606 |
| Depreciation, depletion and amortization | 178,015 | 43,634 | 78 | (a) | (23,393) | (c) | 198,334 |
| Impairment of oil and natural gas properties | 245,536 | 189,827 | (67) | (a) | — | | 435,296 |
| Impairment of field inventories | — | 501 | — | | (501) | (d) | — |
| Bad debt expense | — | 344 | — | | — | | 344 |
| General and administrative expenses | 42,619 | 7,212 | — | | (7,212) | (d) | 42,619 |
| Asset retirement obligation accretion expense | 1,064 | — | — | | 90 | (f) | 1,154 |
| Total costs and expenses | 595,724 | 265,094 | 71 | | (31,016) | | 829,873 |
| **Income (loss) from operations** | (68,617) | (166,626) | 1,655 | | 31,016 | | (202,572) |
| **Other income (expense)** | | | | | | | |
| Interest income (expense) | (40,684) | (399) | — | | 399 | (d) | (40,684) |
| Other income | 3,064 | — | — | | — | | 3,064 |
| Other expense | — | (500) | — | | 500 | (d) | — |
| Gain on derivative instruments, net | (25,345) | (12,031) | — | | 12,031 | (d) | (25,345) |
| Loss on extinguishment of debt | (33,134) | — | — | | — | | (33,134) |
| Total other expense, net | (96,099) | (12,930) | — | | 12,930 | | (96,099) |
| Income (loss) before income taxes | (164,716) | (179,556) | 1,655 | | 43,946 | | (298,671) |
| Provision for (benefit from) income taxes | 192 | (492) | — | | 492 | (e) | 192 |
| **Net income (loss)** | (164,908) | (179,064) | 1,655 | | 43,454 | | (298,863) |
| Net income attributable to non-controlling interest | 126 | — | — | | — | | 126 |
| **Net income (loss) attributable to Diamondback Energy, Inc.** | $ (165,034) | $ (179,064) | $ 1,655 | | $ 43,454 | | $ (298,989) |

## 1. DESCRIPTION OF THE ACQUISITION

On February 28, 2017, Diamondback completed the acquisition of certain oil and natural gas properties, midstream service assets and other related assets from Brigham. Diamondback used the net proceeds from its December 2016 equity offering, net proceeds from its December 2016 debt offering, cash on hand and other financing sources to fund the cash portion of the purchase price for this acquisition.

We refer to the acquisition of the oil and natural gas properties, midstream assets and other related assets from Brigham as the "Acquisition."

## 2. BASIS OF PRESENTATION

The unaudited pro forma condensed combined financial statements were prepared using the acquisition method of accounting in accordance with generally accepted accounting principles in the United States (GAAP) and were derived based on the historical financial statements of Diamondback and the financial statements of Brigham after giving effect to the Acquisition and after applying the reclassifications and adjustments described in the accompanying notes to the unaudited pro forma condensed combined financial statements. The unaudited pro forma condensed combined balance sheet as of December 31, 2016 is presented as if the Acquisition had occurred on December 31, 2016. The unaudited pro forma condensed combined statement of operations for the year ended December 31, 2016 is presented as if the Acquisition had occurred on January 1, 2016.

The unaudited pro forma condensed combined financial statements are presented for information purposes only and are not intended to reflect the results of operations or financial position of the combined company that would have resulted had the Acquisition been effective during the period presented or the results that may be obtained by the combined company in the future. Additionally, the unaudited pro forma condensed combined financial statements should be read in conjunction with the historical audited consolidated financial statements and accompanying notes of Diamondback included in our Annual Report on Form 10-K for the year ended December 31, 2016 as well as Brigham's historical audited financial statements and accompanying notes for the year ended December 31, 2016, included as Exhibit 99.1 in this Current Report on Form 8-K/A.

## 3. ADJUSTMENTS

(a) Reflects exclusion of Brigham Illinois Basin assets not included in the Acquisition and inclusion of additional net mineral acres included in the Acquisition.

## 4. PRO FORMA ADJUSTMENTS

The following pro forma adjustments have been reflected in the unaudited pro forma condensed combined financial statements. Such information does not purport to be indicative of the results of operations or financial position that actually would have resulted had the Acquisition occurred on the date indicated, nor is it indicative of the results that may be expected in future periods. The pro forma adjustments are based upon information and assumptions available at the time of filing the Current Report on Form 8-K/A to which these unaudited pro forma condensed combined financial statements are an exhibit.

(b) To eliminate the assets, liabilities and net investment not acquired or assumed in the Acquisition, to record the Acquisition for $1.74 billion in cash and 7.69 million shares, and to allocate the purchase price to the assets acquired and liabilities assumed. The allocation of the purchase price to the assets acquired and liabilities assumed is preliminary and, therefore, subject to change. Any future adjustments to the allocation of the purchase price are not expected to have a material effect on Diamondback’s financial condition, results of operations or cash flows.

| The allocation of the purchase price of the Acquisition to the fair value of the assets acquired and liabilities assumed is as follows (in thousands): | | |
|---|---|---|
| Proved oil and natural gas properties | $ | 387,571 |
| Unevaluated oil and natural gas properties | | 2,122,415 |
| Midstream assets | | 47,554 |
| Prepaid capital costs | | 3,460 |
| Oil inventory | | 839 |
| Revenues payable | | (8,723) |
| Asset retirement obligations | | (1,550) |
| | $ | 2,551,566 |

(c) Reflects depletion, depreciation and amortization of oil and natural gas properties associated with the Acquisition recorded on a combined basis under the full cost method.
(d) Reflects elimination of Brigham expenses not associated with the Acquisition.
(e) Reflects elimination of income tax benefit of Brigham as income tax provision is calculated on a combined basis.
(f) Reflects the calculation of asset retirement obligation accretion expense on a combined basis.

## 4. SUPPLEMENTAL PRO FORMA COMBINED OIL AND GAS RESERVE AND STANDARDIZED MEASURE INFORMATION (Unaudited)

The following table sets forth unaudited pro forma information with respect to Diamondback's estimated proved reserves, including changes therein, and proved developed and proved undeveloped reserves for the year ended December 31, 2016, giving effect to the Acquisition as if it had occurred on January 1, 2016. The estimates of reserves attributable to the Acquisition may include development plans for those properties which are different from those that the Company will ultimately implement. Reserve estimates are inherently imprecise, require extensive judgments of reservoir engineering data and are generally less precise than estimates made in connection with financial disclosures.

| | Diamondback Historical | | | | | Brigham | | | Total Pro Forma | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil (MBbls) | | Natural Gas Liquids (MBbls) | | Natural Gas (MMcf) | Oil (MBbls) | Natural Gas Liquids (MBbls) | Natural Gas (MMcf) | Oil (MBbls) | Natural Gas Liquids (MBbls) | Natural Gas (MMcf) |
| **Proved Developed and Undeveloped Reserves:** | | | | | | | | | | | |
| **As of January 1, 2015** | 105,979 | — | 26,004 | — | 149,503 | 31,804 | 5,276 | 25,877 | 137,783 | 31,280 | 175,380 |
| Extensions and discoveries | 55,069 | — | 13,962 | — | 64,758 | 11,419 | 1,913 | 7,856 | 66,488 | 15,875 | 72,614 |
| Revisions of previous estimates | (12,483) | — | (1,888) | — | (34,519) | 4,607 | 711 | 2,825 | (7,876) | (1,177) | (31,694) |
| Purchase of reserves in place | 2,171 | — | 1,455 | — | 5,582 | (10,941) | (1,774) | (11,163) | (8,770) | (319) | (5,581) |
| Production | (11,562) | — | (2,399) | — | (10,428) | (2,267) | (370) | (1,609) | (13,829) | (2,769) | (12,037) |
| **As of December 31, 2016** | 139,174 | | 37,134 | | 174,896 | 34,622 | 5,756 | 23,786 | 173,796 | 42,890 | 198,682 |
| **Proved Developed Reserves:** | | | | | | | | | | | |
| December 31, 2016 | 79,457 | | 22,080 | | 105,399 | 12,506 | 2,318 | 16,500 | 91,963 | 24,398 | 121,899 |
| **Proved Undeveloped Reserves:** | | | | | | | | | | | |
| December 31, 2016 | 59,717 | | 15,054 | | 69,497 | 22,117 | 3,439 | 27,844 | 81,834 | 18,493 | 97,341 |

The following pro forma standardized measure of the discounted net future cash flows and changes applicable to proved reserves reflect the effect of income taxes assuming the Acquisition had been subject to federal income tax at a rate of 35%. The future net cash flows are based on a 10% annual discount rate. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to Diamondback. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

| | Diamondback Historical | Brigham | Pro Forma as Adjusted |
|---|---|---|---|
| | (In thousands) | | |
| Future cash inflows | $ 6,275,705 | $ 1,478,098 | $ 7,753,803 |
| Future development costs | (617,636) | (489,787) | (1,107,423) |
| Future production costs | (1,392,852) | (428,316) | (1,821,168) |
| Future production taxes | (459,244) | — | (459,244) |
| Future income tax expenses | (75,595) | (7,469) | (83,064) |
| Future net cash flows | 3,730,378 | 552,526 | 4,282,904 |
| 10% discount to reflect timing of cash flows | (2,018,965) | (328,150) | (2,347,115) |
| Standardized measure of discounted future net cash flows | $ 1,711,413 | $ 224,376 | $ 1,935,789 |

The changes in Diamondback's pro forma standardized measure of discounted estimated future net cash flows were as follows for 2016:

| | Diamondback Historical | Brigham | Pro Forma as Adjusted |
|---|---|---|---|
| | (In thousands) | | |
| Standardized measure of discounted future net cash flows at the beginning of the period | $ 1,418,133 | $ 255,044 | $ 1,673,177 |
| Sales of oil and natural gas, net of production costs | (411,558) | (77,295) | (488,853) |
| Purchase of minerals in place | 37,661 | (35,341) | 2,320 |
| Extensions and discoveries, net of future development costs | 779,359 | 56,180 | 835,539 |
| Previously estimated development costs incurred during the period | 85,696 | (53,143) | 32,553 |
| Net changes in prices and production costs | (150,509) | (20,339) | (170,848) |
| Changes in estimated future development costs | 20,647 | 35,749 | 56,396 |
| Revisions of previous quantity estimates | (123,795) | 25,903 | (97,892) |
| Accretion of discount | 143,134 | 35,015 | 178,149 |
| Net change in income taxes | (30,530) | (142) | (30,672) |
| Net changes in timing of production and other | (56,825) | 2,358 | (54,467) |
| Standardized measure of discounted future net cash flows at the end of the period | $ 1,711,413 | $ 223,989 | $ 1,935,402 |