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

FORM 8-K

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

Date of report (Date of earliest event reported): April 18, 2017

GULFPORT ENERGY CORPORATION
(Exact Name of Registrant as Specified in Charter)

Delaware	**000-19514**	**73-1521290**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(I.R.S. Employer Identification Number)**

3001 Quail Springs Parkway **Oklahoma City, Oklahoma**	**73134**
(Address of principal executive offices)	**(Zip code)**

(405) 848-8807
(Registrant's telephone number, including area code)

(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 ☐

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. ☐

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:

☐ Written communications pursuant to Rule 425 under the Securities Act

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act

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

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

Item 8.01. Other Events.

As previously disclosed, on February 17, 2017, Gulfport Energy Corporation (the “Company”), through its wholly-owned subsidiary Gulfport MidCon LLC (“Gulfport MidCon”) (formerly known as SCOOP Acquisition Company, LLC), completed its acquisition (the “Acquisition”) of certain assets from Vitruvian II Woodford, LLC, an unrelated third-party seller (the “Seller”), under its previously reported Purchase and Sale Agreement (the “Purchase Agreement”) by and among the Seller, the Company and Gulfport MidCon, dated as of December 13, 2016, as amended and supplemented by that certain Closing Agreement and Amendment, dated as of February 17, 2017, by and among the Seller, the Company and Gulfport MidCon. This Current Report on Form 8-K is being filed solely for the purpose of updating certain historical and pro forma financial statements relating to the Acquisition, originally filed on the Company’s Current Report on Form 8-K on December 15, 2016 in connection with the signing of the Purchase Agreement.

Item 9.01. Financial Statements and Exhibits

(a) Financial Statements of Business Acquired.

- Audited financial statements of Vitruvian II Woodford, LLC, comprised of the balance sheets as of December 31, 2016 and 2015, and the related statements of operations, changes in members’ equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and the related notes to the financial statements, attached as Exhibit 99.1 hereto.

(b) Pro Forma Financial Statements

The following unaudited pro forma consolidated financial information of Gulfport, giving effect to the Acquisition and the related financing transactions, is included in Exhibit 99.2 hereto:

- Unaudited Pro Forma Consolidated Balance Sheet as of December 31, 2016.
- Unaudited Pro Forma Consolidated Statement of Operations for the year ended December 31, 2016.

(d) *Exhibits*

Number	Exhibit
23.1	Consent of PricewaterhouseCoopers LLP.
99.1	Historical audited financial statements of Vitruvian II Woodford, LLC.
99.2	Unaudited pro forma consolidated financial information.

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.

GULFPORT ENERGY CORPORATION

Date: April 18, 2017

By: /s/ Keri Crowell
Keri Crowell
Chief Financial Officer

Exhibit Index

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99.2	Unaudited pro forma consolidated financial information.

Exhibit 23.1

Consent of Independent Accountants

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File No. 333-206564, File No. 333-135728, File No. 333-129178, and File No. 333-55738) and on Form S-3 (File No. 333-215078) of Gulfport Energy Corporation of our report dated February 17, 2017, relating to the financial statements of Vitruvian II Woodford, LLC, which appears in this Current Report on Form 8-K of Gulfport Energy Corporation dated April 18, 2017.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
April 18, 2017

Exhibit 99.1

VITRUVIAN II WOODFORD, LLC

Financial Statements

As of December 31, 2016 and 2015 and
for the years ended December 31, 2016, 2015 and 2014

VITRUVIAN II WOODFORD, LLC
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Report of Independent Auditors

To the Board of Directors and Management of
Vitruvian II Woodford, LLC

We have audited the accompanying financial statements of Vitruvian II Woodford, LLC (the “Company”), which comprise the balance sheets as of December 31, 2016 and 2015, and the related statements of operations, changes in members’ equity and cash flows for December 31, 2016, 2015 and 2014 for the years then ended.

Management’s Responsibility for the Financial Statements

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

Auditors’ Responsibility

Our responsibility is to express an opinion on the 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company’s preparation and fair presentation of the 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 Company’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 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 financial statements referred to above present fairly, in all material respects, the financial position of Vitruvian II Woodford, LLC as of December 31, 2016 and 2015, and the results of its operations and its cash flows for the years ended December 31, 2016, 2015 and 2014 in accordance with accounting principles generally accepted in the United States of America.

/s/ Pricewaterhouse Coopers LLP

Houston, TX
February 17, 2017

VITRUVIAN II WOODFORD, LLC
BALANCE SHEET
(In thousands)

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,632	$ 2,509
Accounts receivable, net:		
Oil and gas	38,304	16,246
Affiliates	2,187	1,177
Total accounts receivable, net	40,491	17,423
Derivative contracts	2,275	66,951
Prepaid and other current assets	12,834	4,784
Total current assets	58,232	91,667
Property and equipment, at cost:		
Oil and natural gas properties (full cost method):		
Proved	884,728	691,464
Unproved	368,238	373,597
Other property and equipment	17,199	13,434
Total property and equipment	1,270,165	1,078,495
Less: accumulated depreciation, depletion and amortization	(498,256)	(243,343)
Net property and equipment	771,909	835,152
Deferred financing costs	1,386	2,602
Derivative contracts	—	14,918
Other assets	28	28
Total assets	$ 831,555	$ 944,367
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable	$ 9,307	$ 8,761
Accrued liabilities	42,320	37,897
Royalties and revenue payable	18,010	7,960
Derivative contracts	15,384	—
Current maturities of long-term debt	221,500	31,000
Total current liabilities	306,521	85,618
Long-term debt	98,731	306,653
Derivative contracts	6,443	—
Asset retirement obligations	6,647	6,184
Total liabilities	418,342	398,455
Commitments and contingencies (Note 11)		
Members' equity	413,213	545,912
Total liabilities and members' equity	$ 831,555	$ 944,367

The accompanying notes are an integral part of these financial statements.

VITRUVIAN II WOODFORD, LLC
STATEMENT OF OPERATIONS
(In thousands)

	Year Ended December 31,		
	2016	2015	2014
Revenues:			
Oil	$ 49,585	$ 39,972	$23,054
Natural gas	96,741	53,674	38,084
Natural gas liquids	29,070	17,693	17,237
Total revenues	175,396	111,339	78,375
Operating expenses:			
Lease operating	6,819	7,182	5,331
Gathering, transportation and processing	42,042	24,306	10,408
Production and other taxes	3,055	1,810	2,229
Depreciation, depletion and amortization	64,751	49,497	23,008
Impairment of oil and natural gas properties	190,532	140,165	—
General and administrative	17,553	6,824	8,960
Total operating expenses	324,752	229,784	49,936
Operating income (loss)	(149,356)	(118,445)	28,439
Other income (expense):			
Interest expense	(18,660)	(11,664)	(3,325)
Interest capitalized	18,660	11,664	3,325
Gain (loss) on derivative contracts, net	(38,209)	87,040	53,506
Loss on sale of assets	(85)	—	(2)
Total other income (expense)	(38,294)	87,040	53,504
Income (loss) before taxes	(187,650)	(31,405)	81,943
Income tax expense	(49)	(7)	(16)
Net income (loss)	$(187,699)	$ (31,412)	$81,927

The accompanying notes are an integral part of these financial statements.

VITRUVIAN II WOODFORD, LLC
STATEMENT OF CHANGES IN MEMBERS' EQUITY
(In thousands)

Balance at January 1, 2014	$ 495,397
Net income	81,927
Balance at December 31, 2014	577,324
Net loss	(31,412)
Balance at December 31, 2015	545,912
Members' contributions	55,000
Net loss	(187,699)
Balance at December 31, 2016	$ 413,213

The accompanying notes are an integral part of these financial statements.

VITRUVIAN II WOODFORD, LLC
STATEMENT OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2016	**2015**	**2014**
Cash flows from operating activities:			
Net income (loss)	$(187,699)	$ (31,412)	$ 81,927
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	64,751	49,497	23,008
Impairment of oil and natural gas properties	190,532	140,165	—
Loss on sale of assets	85	—	2
(Gain) loss on derivative contracts, net	38,209	(87,040)	(53,506)
Cash receipts on derivative contract settlements, net	59,194	62,015	1,445
Allowance for doubtful accounts	4,365	—	—
Amortization of deferred financing costs	1,826	1,411	271
Changes in operating assets and liabilities:			
Accounts receivable – oil and gas	(27,339)	(1,344)	(8,691)
Accounts receivable – affiliates	(1,010)	(753)	(85)
Prepaid and other current assets	180	(2,756)	(3,867)
Accounts payable	(198)	1,790	3,543
Accrued liabilities	12,164	1,867	1,072
Royalties and revenue payable	10,050	2,186	3,030
Other liabilities	(34)	(41)	(161)
Net cash provided by operating activities	165,076	135,585	47,988
Cash flows from investing activities:			
Investments in oil and natural gas properties	(197,259)	(301,210)	(166,196)
Investments in other property and equipment	(1,681)	(9,121)	(3,478)
Proceeds from the sale of assets	19	150	29
Restricted cash	(3,000)	—	—
Net cash used in investing activities	(201,921)	(310,181)	(169,645)
Cash flows from financing activities:			
Proceeds from borrowings under Credit Facility	20,000	172,653	125,000
Repayments of borrowings under Credit Facility	(136,153)	—	—
Issuance of long-term debt	100,000	—	—
Debt issuance costs	(1,879)	(2,858)	(881)
Member Contributions	55,000	—	—
Net cash provided by financing activities	36,968	169,795	124,119
Net increase (decrease) in cash and cash equivalents	123	(4,801)	2,462
Cash and cash equivalents, beginning of period	2,509	7,310	4,848
Cash and cash equivalents, end of period	$ 2,632	$ 2,509	$ 7,310
Supplemental cash flow disclosures:			
Interest paid, net of amounts capitalized	$ —	$ —	$ —
Income taxes paid	49	7	16
Non-cash investing and financing activities – at period end:			
Capital expenditures included in accrued liabilities	24,682	32,427	32,521

The accompanying notes are an integral part of these financial statements.

VITRUVIAN II WOODFORD, LLC
NOTES TO FINANCIAL STATEMENTS

(*Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.)*

References to "we," "us" and "our" mean Vitruvian II Woodford, LLC.

1. Organization and Description of Operations and Basis of Presentation

Organization

We were formed as a Delaware limited liability company on November 14, 2012 by members of our senior management team and affiliates of Quantum Energy Partners ("Quantum"), a private equity investment firm engaged in the acquisition and development of oil and natural gas properties.

Description of Operations

We are an independent energy company engaged in the acquisition, exploration, development and production of crude oil, natural gas and natural gas liquids ("NGLs"). We operate and have non-operating interests in producing wells within the Woodford and Springer shale formations in the South Central Oklahoma Oil Province, or SCOOP, resource play.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Significant estimates and assumptions include:

- estimated future net cash flows from proved reserves;
- depreciation, depletion and amortization expense ("DD&A");
- asset retirement obligations ("AROs");
- capitalized general and administrative ("G&A") expenses and interest;
- unevaluated property costs;
- fair value of properties acquired and liabilities assumed;
- revenue and expense accruals;
- fair value of derivative contracts; and
- fair value of unit-based compensation.

Actual results may differ from the estimates, judgments and assumptions used in the preparation of our financial statements.

2. Summary of Significant Accounting Policies

Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of three months or less from the date of measure.

Restricted Cash

Certain cash balances included in "Other assets" on our balance sheet are classified as restricted and consist of certificates of deposit that serve as collateral for certain performance bonds. These assets will continue to be restricted as long as we conduct oil and natural gas operations.

Accounts Receivable

We routinely assess the recoverability of our accounts receivable, which are comprised of amounts due from (i) purchasers of our oil, natural gas and NGL production and (ii) joint interest owners on properties that we operate. Generally, our oil and gas receivables are collected within 45 to 60 days of production and our joint interest billings are collected within the month after they are billed. We have the ability to withhold future revenue distributions to recover any nonpayment of our joint interest billings.

We establish provisions for losses on accounts receivable if we determine that it is likely that all or part of an outstanding balance will not be collected. As of December 31, 2016, we had a $5.2 million allowance for doubtful accounts. As of December 31, 2015, we had no allowance for doubtful accounts.

Concentration of Credit Risk

We sell a significant amount of our oil, natural gas and NGL production to a limited number of purchasers. The following table identifies customers from whom we derived 10% or more of receipts from the sale of oil and natural gas during the years ended December 31, 2016, 2015 and 2014. We believe that the loss of any of the customers listed below would not result in a material adverse effect on our ability to market future oil and natural gas production.

	2016	2015	2014
Laclede Energy Resources	21%	*	*
DCP NGL Services, LLC	13%	*	*
Southwest Energy LP	12%	*	26%
Murphy Energy Corporation	*	23%	21%
Woodford Express, LLC	*	17%	15%

* Purchaser did not account for greater than 10% of revenues for the year.

Financial instruments that potentially subject us to concentrations of credit risk include our cash and cash equivalents, accounts receivable and derivative contracts. We attempt to minimize credit risk exposure associated with these instruments by placing our assets and other financial interests with credit-worthy institutions and maintaining credit policies, monitoring procedures and letters of credit or guaranties when considered necessary.

Derivative Contracts

We may periodically enter into derivative contracts to manage our exposure to commodity price and interest rate changes. These derivative contracts may take the form of forward contracts, futures contracts, swaps, collars or options. We do not use derivative contracts for trading purposes.

We record our derivative contracts at fair value and do not designate any of our derivative contracts as hedging instruments for accounting purposes. As such, unrealized gains and losses from changes in the valuation of our unsettled derivative contracts are reported in gain on derivative contracts, net, in our statement of operations.

We are exposed to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. To minimize the credit risk in derivative contracts, we enter into derivative contracts only with counterparties that are lenders under our Credit Facility. As of December 31, 2016, we had no past-due receivables from any counterparty. See Notes 7 and 8 for a discussion of the use of derivative instruments, management of credit risk inherent in derivative instruments and fair value information.

Deferred Financing Costs

We capitalize costs incurred in connection with obtaining financing and amortize such costs as additional interest expense over the life of the underlying indebtedness.

Oil and Natural Gas Properties

We use the full cost method of accounting for oil and natural gas properties and equipment. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties, including salaries, benefits, interest and other internal costs directly attributable to these activities, are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include costs of drilling exploratory wells and external geological and geophysical costs. Development costs include the cost of drilling development wells and costs of completions, facilities and gathering systems. Costs associated with production, certain geological and geophysical costs and G&A costs that are not capitalized as described above are expensed in the period incurred. During the years ended December 31, 2016, 2015 and 2014, we capitalized $6.3 million, $8.1 million and $6.5 million, respectively, of salaries, benefits and other internal costs that were directly related to the acquisition, exploration and development activities of our unproved properties. We capitalize interest on expenditures made in connection with the exploration and development of unproved properties that are excluded from the amortization base. Interest is capitalized for the period that exploration and development activities are in progress. During the years ended December 31, 2016, 2015 and 2014, we capitalized $18.7 million, $11.7 million and $3.3 million, respectively, of interest.

DD&A of producing oil and natural gas properties is calculated using the units-of-production method, which is calculated by dividing the amortization base by the volume of total proved reserves, multiplied by the volume of oil and natural gas produced during the period. The amortization base includes the sum of proved property costs net of accumulated DD&A, estimated future development costs (future costs to assess and develop proved reserves) and asset retirement costs that are not already included in oil and gas property, less related salvage value. Our DD&A per Mcfe was $1.08, $1.43 and $1.70 for the years ended December 31, 2016, 2015 and 2014, respectively.

Oil and natural gas properties and equipment include costs of unproved properties, which are excluded from the amortization base until it is determined that proved reserves can be assigned to such properties or until such time that management has made an evaluation that impairment has occurred. All costs excluded from the amortization base are reviewed quarterly to determine if impairment has occurred and evaluation of these properties is expected to be completed within ten years. The costs of drilling exploratory dry holes are included in the amortization base immediately upon determination that such wells are not commercial.

Sales of proved oil and natural gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Impairment of Oil and Gas Properties

Under the full cost method of accounting, we are required to perform a quarterly ceiling test, which establishes a limit on the book value of oil and natural gas properties. The capitalized costs of proved oil and natural gas properties, net of accumulated DD&A and related deferred income taxes, may not exceed this “ceiling.” The ceiling limitation is equal to the sum of (i) the present value of estimated future net revenues from the projected production of proved oil and natural gas reserves, excluding future cash outflows associated with settling AROs accrued on the balance sheet, calculated using the average oil and natural gas sales price as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) and a discount factor of 10%; (ii) the cost of unproved and unevaluated properties excluded from the costs being amortized; (iii) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (iv) related income tax effects. If capitalized costs exceed this ceiling, the excess is charged as impairment expense and any write downs are not recoverable or reversible in future periods.

During the years ended December 31, 2016 and 2015, we recorded an impairment to the carrying value of our oil and natural gas properties of $190.5 million and $140.2 million, respectively. The lower ceiling values resulted primarily from significant decreases in the trailing twelve month average prices for oil and natural gas, which significantly reduced proved reserves values. There was no impairment recorded during the year ended December 31, 2014.

Other Property and Equipment

Other property and equipment primarily consists of water infrastructure facilities, compressors, furniture, fixtures and other equipment. Other property and equipment is recorded at cost and depreciated using the straight-line method over the estimated useful lives of the respective assets, generally ranging from three to ten years. Leasehold improvements are amortized over the shorter of their economic lives or the lease term. The cost of maintenance and repairs are expensed in the period incurred. Expenditures that extend the life or improve existing property and equipment are capitalized.

Oil and Natural Gas Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable in the future from established reservoirs under current operating and economic parameters. We prepare an estimate of proved reserves on a quarterly basis in conjunction with our DD&A calculation and ceiling test. Proved reserves are calculated based on various factors, including an independent reserve engineer’s report on proved reserves and an economic evaluation of all of our properties on a well-by-well basis.

Reserve quantities and their associated estimated future net cash flows impact depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data; the interpretation of that data; the accuracy of various economic assumptions; and the judgment of the individuals preparing the estimates. Proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas that are eventually recovered.

Asset Retirement Obligations

AROs are legal obligations associated with the plugging and abandonment of our oil and natural gas wells and associated equipment. We record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related asset in the period in which our assets are placed in service or acquired. Over time, the ARO liability is accreted to its present value, and the capitalized cost is depleted using the units-of-production method.

Upon initial recognition, AROs are recorded at their fair values using expected present value techniques based on historical experience and third-party proposals for plugging and abandoning wells. The estimated remaining life of each well is based on reserve life estimates and federal and state regulatory requirements. Revisions in estimated AROs may result from changes in estimated inflation rates, service and equipment costs and estimated timing of settlement.

Our AROs relate to the plugging and abandonment of oil and natural gas wellbores and to decommissioning related pipelines and facilities.

Revenue Recognition and Natural Gas Imbalances

We recognize oil and natural gas revenues based on the quantities of our production sold to purchasers at market prices when delivery has occurred, title has transferred and collectability is reasonably assured. We use the sales method of accounting for oil and natural gas revenues from properties with joint ownership. Under this method, we record oil and natural gas revenues based on physical deliveries to our purchasers, which can be different from our entitled share of production. These differences create imbalances that we recognize as a liability only when the estimated remaining recoverable reserves of a property will not be sufficient to enable the under-produced party to recoup its entitled share through production. We do not record receivables for those properties in which we have taken less than our ownership share of production. At December 31, 2015, our natural gas imbalance was a payable of less than $0.1 million.

Segment Reporting

We operate in only one segment: the exploration and production of oil, natural gas and NGLs in the United States. All of our operations are conducted in one geographic area of the United States, and all of our revenues are derived from customers located in the United States.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. In the preparation of our financial statements, management assesses the need for accounting recognition or disclosure of these contingencies, if any, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in such proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

When applicable, we will accrue an undiscounted liability for contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount within the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote.

For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, if feasible, an estimate of the possible loss or range of loss. Loss contingencies considered remote are generally not disclosed. See Note 11 for additional information regarding our contingencies.

Income Taxes

As a limited liability company, we are not a taxpaying entity for federal income tax purposes. Our results of operations are included in the taxable income of our members, and, accordingly, we do not recognize any provision for federal income taxes in our financial statements. Income and losses for tax purposes may differ from our financial statement amounts and may be allocated to members on a different basis for tax purposes than for financial statement purposes. The basis of members’ capital reflected in our financial statements does not represent the members’ tax basis of their respective interests.

We are subject to state income tax in Oklahoma associated with certain of our royalty interests and recorded less than $0.1 million of such expense during the years ended December 31, 2016, 2015 and 2014.

Unit-Based Compensation

Compensation expense related to unit-based payments made to employees is based on the estimated fair value of the equity instruments on the date of grant, net of estimated forfeitures, and is recognized on a straight-line basis over the requisite service period, which is generally the vesting period.

3. Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by various accounting standard-setting bodies.

In February 2016, the FASB issued ASU 2016-02, Leases. This new standard introduces a new lease model that requires the recognition of right-of-use assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. The new guidance will be effective for annual periods beginning after December 15, 2019, and interim periods thereafter. Upon adoption of this standard, a modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are currently assessing the potential impact of this new standard on our financial statements and related disclosures.

In April 2015, the FASB issued ASU 2015-03 which simplifies the presentation of debt issuance costs. This ASU requires companies to present debt issuance costs as a direct deduction from the carrying value of that debt liability for non-revolver type debt. ASU 2015-03 does not impact the recognition and measurement guidance for debt issuance costs. Additionally, in August 2015, the FASB issued ASU 2015-15, Interest-Imputation of Interest: Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (ASU 2015-15). These ASUs are effective for annual reporting periods beginning after December 15, 2015 and early adoption was permitted. Accordingly, we adopted this ASU on December 31, 2016 and reclassified $1.3 million of unamortized debt issuance costs associated with our second lien term loan from deferred financing costs to a reduction of long-term debt on the balance sheet. Adoption of ASU 2015-03 had no impact on our current and previously reported members’ equity, results of operations or cash flows. Unamortized debt issuance costs of $1.4 million and $2.6 million as of December 31, 2016 and 2015, respectively, associated with our revolving credit facility were not reclassified and remain in deferred financing costs on the balance sheet. See Note 5 for additional detail.

In August 2014, the FASB issued ASU 2014-15 which provides guidance regarding disclosures of uncertainties about an entity’s ability to continue as a going concern. The guidance applies prospectively to all entities, requiring management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity’s ability to continue as a going concern and disclose certain information when substantial doubt exists. We adopted this guidance for the annual period ending December 31, 2016, and there was no material impact on our financial statements.

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers, ASU 2014-09. In April and May 2016, the FASB issued additional guidance under ASU 2016-12, addressed implementation issues and provided technical corrections. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings. The guidance is effective for interim and annual periods beginning on or after December 15, 2018. We are currently evaluating the impact of this guidance on our financial statements.

4. Oil and Natural Gas Properties

Capitalized Costs

The following table summarizes the capitalized costs of our oil and natural gas properties:

	December 31, 2016	December 31, 2015
Oil and natural gas properties:		
Proved	$ 884,728	$ 691,464
Unproved, excluded from amortization	368,238	373,597
Total oil and natural gas properties	1,252,966	1,065,061
Less: accumulated DD&A	(496,459)	(242,266)
Net oil and natural gas properties	$ 756,507	$ 822,795

Proved oil and natural gas properties at December 31, 2016 and 2015 includes $5.6 million and $5.5 million, respectively, related to capitalized plugging, abandonment and site restoration costs.

Costs Not Amortized

The following table summarizes the capitalized costs classified within unproved properties that are not subject to amortization at December 31, 2016.

		Costs Incurred In			
	Total	2016	2015	2014	Prior to 2014
Costs not subject to amortization:					
Acquisition costs	$285,673	$20,653	$ 8,895	$ 7,009	$249,116
Exploration costs	25,965	22,146	922	1,506	1,391
Development costs	3,774	3,284	57	433	—
Capitalized interest	31,637	18,660	9,880	2,144	953
Capitalized G&A expenses	21,189	6,308	6,861	4,196	3,824
Total unproved properties	$368,238	$71,051	$26,615	$15,288	$255,284

Oil and gas properties not subject to amortization represent investments in unproved properties in which we own an interest. These unproved property costs include unevaluated leasehold acreage, the majority of which is held by production, geological and geophysical data costs associated with leasehold or drilling interests, costs associated with wells in progress at December 31, 2016 and capitalized internal costs. Costs associated with wells in progress are transferred to the amortization base upon the determination of whether proved reserves can be assigned to the properties, which is generally based on drilling results. All costs excluded from the amortization base are associated with our activities in SCOOP and will continue to be transferred to the full cost pool as we further prove and develop the underlying acreage.

Costs Incurred in Oil and Natural Gas Activities

The following table summarizes the costs incurred related to our oil and natural gas producing activities for the years ended December 31, 2016, 2015 and 2014:

	December 31, 2016	December 31, 2015	December 31, 2014
Acquisition costs:			
Proved	$ —	$ 92	$ 16
Unproved	20,584	10,350	10,871
Exploration costs	135,340	280,447	157,910
Development costs	31,981	8,992	24,008
Total costs incurred	$187,905	$299,881	$192,805

5. Long Term Debt

We have a senior secured revolving credit agreement (the “Credit Facility”) with Wells Fargo Bank, N.A. (“Wells Fargo”) as administrative agent and other lenders. During 2015, we amended this agreement such that it now provides funding up to $650.0 million under two tranches: (i) Tranche A, which matures December 27, 2017, is subject to a borrowing base and is secured by a first lien on substantially all of our assets and (ii) Tranche B, which matured upon closing of a second lien term loan in June 2016, was supported by unfunded capital commitments of our equity sponsors. At December 31, 2016, we had a total of $221.5 million of principal outstanding under Tranche A, all of which was classified under current maturities of long-term debt on our balance sheet. At December 31, 2015, we had a total of $337.7 million of principal outstanding under Tranche A and Tranche B, $31.0 million of which was classified under current maturities of long-term debt on our balance sheet.

Borrowing Base

The amount we may borrow under Tranche A is limited by a borrowing base based on our oil and natural gas properties, proved reserves, total indebtedness and other factors consistent with customary lending criteria. The borrowing base is re-determined quarterly through April 1, 2016 and at least semi-annually thereafter. As of December 31, 2016 and 2015, the borrowing base was $272.0 million and $370.0 million, respectively. The borrowing bases for Tranche A and Tranche B were $295.0 million and $75.0 million, respectively, at December 31, 2015.

Interest

Interest on borrowings is calculated using the adjusted base rate (“ABR”) or the London Interbank Offering Rate (“LIBOR”), plus an applicable margin. The applicable margin ranges from 1.0% to 2.75% for ABR loans and from 2.0% to 3.75% for LIBOR loans, depending on the percentage of the total borrowing base utilization level. In addition to interest, we pay various fees, including a commitment fee equal to 0.50% per annum on the unutilized commitment, which is included within interest expense on our statement of operations. The weighted-average interest rate on loan amounts outstanding during the years ended December 31, 2016, 2015 and 2014 was 4.04%, 3.81% and 3.00%, respectively.

Covenants

The Credit Facility contains certain covenants that restrict the payment of cash dividends, borrowings other than from the Credit Facility, sales of assets, loans to others, investments, merger activity, commodity swap agreements, liens and other transactions without the prior consent of the lenders. We are subject to various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio. The Credit Facility also contains representations, warranties, indemnifications and affirmative and negative covenants, including events of default relating to nonpayment of principal, interest or fees, inaccuracy of representations or warranties in any material respect when made or when deemed made, violation of covenants, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default occurs and we are unable to cure such default as allowed by the Credit Facility, the lenders will be able to accelerate the maturity of the Credit Facility and exercise other rights and remedies.

Second Lien Term Loan

On June 17, 2016, we entered into a second lien term loan agreement with Wells Fargo Energy Capital, Inc., as administrative agent, and a syndicate of lenders in the form of a $100.0 million term loan facility which is due on June 27, 2018. The debt governed by this agreement is effectively subordinated to the prior payment in full of the debt under the Credit Facility discussed above.

Pursuant to the second lien term loan, interest on borrowings is calculated using the alternate base rate plus a margin of 8.00% or LIBOR plus a margin of 9.00%. The alternate base rate is defined as the higher of (a) the prime rate established by the administrative agent, (b) the federal funds rate in effect plus 0.50% and (c) the daily three-month LIBOR plus 1.00%. The weighted average interest rate on loan amounts outstanding during the year ended December 31, 2016 was 10.0%.

The table below shows a reconciliation of the aggregate principal amount of the second lien term loan to the balance shown on the balance sheet.

	December 31, 2016
Principal amount of second lien term loan	$ 100,000
Direct deduction of unamortized deferred financing costs	1,269
Long-term debt	$ 98,731

Letters of Credit

From time to time, we may request the issuance of letters of credit for our own account. Letters of credit are subject to a fee of 25 basis points and accrue interest at a rate equal to the margin associated with LIBOR borrowings. At December 31, 2016 and 2015, we had a letter of credit outstanding of $2.3 million and $5.3 million, respectively, which reduces the amount available to borrow under the Credit Facility.

6. Asset Retirement Obligations

We record an ARO for our future plugging, abandonment and site restoration costs related to our oil and natural gas properties. The changes in our AROs for the years ended December 31, 2016, 2015 and 2014 are presented in the table below:

	December 31,		
	2016	2015	2014
Beginning balance	$6,263	$5,733	$5,583
Acquisitions	—	10	—
Additions	97	241	69
Settlements	—	(59)	(250)
Revisions to estimates	—	—	11
Accretion expense	370	338	320
Ending balance	$6,730	$6,263	$5,733

The amount of the above obligation expected to be incurred during 2017 is $0.1 million and is included in accrued liabilities on our balance sheet.

7. Financial Instruments

In the normal course of business, we are exposed to certain risks including changes in the prices of oil, natural gas and NGLs which may impact the cash flows associated with the sale of our future oil and natural gas production. We enter into derivative contracts with lenders under our Credit Facility that consist of either a single derivative instrument or a combination of instruments to manage our exposure to these risks. As of December 31, 2016, our commodity derivative instruments consisted of fixed price swaps, costless collars and three-way collars, which are described below:

Fixed Price Swaps: Under a swap contract, we will receive payment if the settlement price is less than the fixed price and would be required to make a payment to the counterparty is the settlement price is greater than the fixed price.

Costless Collars: A collar consists of a sold call option (ceiling) and a purchased put option (floor) and allows us to benefit from increases in commodity prices up to the ceiling price of the contract and protects us from decreases in commodity prices below the floor price. At settlement, the counterparty is required to make a payment to us if the settlement price is below the floor price, while we are required to make a payment to the counterparty if the settlement price is above the ceiling price. If the settlement price is between the floor price and ceiling price, no payments are due from either party.

Three-Way Collars: Three-way collars consist of a standard costless collar contract described above plus a put option sold by us with a price below the floor price of the collar. The sold put option requires us to make a payment to the counterparty if the settlement price is below the sold put option price. By combining the standard costless collar contract with the additional sold put option, we are entitled to a net payment equal to the difference between the floor price of the standard costless collar and the additional sold put price if the settlement price is equal to or less than the additional sold put price. If the settlement price is greater than the additional sold put price, the result is the same as it would have been with a standard costless collar only.

The table below presents our open commodity derivative contracts at December 31, 2016, none of which were designated as hedging instruments. Volumes are presented in million British Thermal Units ("MMBtu") for natural gas and in barrels ("Bbls") for oil.

Period	Remaining Volume	Weighted Average NYMEX Contract Price per Unit: Swap	Sold Put	Floor	Ceiling	Fair Value
Crude Oil						
Collar						
Jan 2017	3,528	—	—	$78.85	$95.00	$ 87
Jan – Dec 2018	390,000	—	—	46.00	62.50	(359)
Three-Way Collar						
Jan – Dec 2017	853,000	—	$ 45.00	60.00	71.10	3,858
Total crude oil (Bbls)	1,246,528					$ 3,586
Natural Gas						
Fixed Price Swap						
Jan – Dec 2017	10,800,000	$2.82	—	—	—	$ (8,764)
Jan – Dec 2018	14,600,000	2.86	—	—	—	(4,024)
Collar						
Jan – Dec 2017	29,567,539	—	—	$ 2.97	$ 3.46	(9,514)
Jan – Dec 2018	4,950,000	—	—	3.05	3.47	(2,060)
Total natural gas (MMbtu)	59,917,539					$ (24,362)
Total unrealized derivative contracts						$ (20,776)

We are exposed to credit loss in the event of nonperformance by our derivative counterparties; however, we do not currently anticipate that the counterparties will be unable to fulfill their contractual obligations. Additional collateral is not required by us due to the derivative counterparties' collateral rights as a lender under our Credit Facility, and we do not require collateral from our derivative counterparties.

8. Fair Value Measurements

We classify financial assets and liabilities that are measured and reported at fair value on a recurring basis using a hierarchy based on the inputs used in measuring fair value. GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

We classify the inputs used to measure fair value into the following hierarchy:

Level 1: Quoted market prices in active markets for identical assets or liabilities.

Level 2: Quoted market prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets and liabilities in markets that are not active or other than quoted prices that are observable and can be corroborated by observable market data.

Level 3: Unobservable inputs that reflect management's best estimates and assumptions of what market participants would use in measuring the fair value of an asset or liability.

Recurring Fair Value Measurements

The following tables summarize the location and fair value of our open commodity derivative contracts in our balance sheet at December 31, 2016 and 2015. All items included are reported at fair value using market inputs including quoted forward commodity prices, discount rates, and volatility factors (Level 2 inputs).

	Derivative Assets			
	Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location: Current	Balance Sheet Location: Noncurrent
December 31, 2016	$ 3,965	$(2,914)	$ 1,051	$ —
December 31, 2015	76,627	—	61,709	14,918

	Derivative Liabilities			
	Gross Fair Value	Offset in Balance Sheet	Balance Sheet Location: Current	Balance Sheet Location: Noncurrent
December 31, 2016	$ (24,741)	$ 2,914	$(15,384)	$ (6,443)
December 31, 2015	—	—	—	—

The tables above exclude realized derivative contracts of $1.2 million and $5.2 million for which cash had not been received at December 31, 2016 and 2015, respectively.

Changes in the fair value of our commodity derivative contracts are recognized currently in earnings and were as follows for the years ended December 31, 2016, 2015 and 2014:

	Location in Statements of Operations	Year Ended December 31, 2016	2015	2014
Derivative gain:				
Realized gain	Gain (loss) on derivative contracts, net	$ 59,194	$62,015	$ 1,445
Unrealized gain	Gain (loss) on derivative contracts, net	(97,403)	25,025	52,061
Gain (loss) on derivative contracts, net		$(38,209)	$87,040	$53,506

Nonrecurring Fair Value Measurements

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis (e.g., oil and natural gas properties) and are subject to fair value adjustments under certain circumstances. The inputs used to determine such fair value are primarily based upon internally developed cash flow models, as well as market-based valuations as discussed in Note 2 and are classified within Level 3.

Other Fair Value Measurements

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities and royalties and revenue payable approximate their fair values due to the short-term maturities of these instruments. Our current and long-term debt obligations under the Credit Facility also approximate fair value since the associated variable rates of interest are market based.

9. Members' Equity

Our Limited Liability Company Agreement (the "LLC Agreement") provides for the issuance of three classes of membership interests: a Capital Interest; a Management Incentive Interest; and a Key Employee

Interest. Each member's relative rights, privileges, preferences and obligations are represented by such membership interest. Members owning Capital Interests have voting rights and other interest owners do not. Capital Interest owners are obligated to make Capital Contributions to us, while Management Incentive Interest and Key Employee Interest owners have no such obligation. To the extent we make distributions to our members, such distributions will be made in accordance with a certain order of priority and in amounts that are based upon each membership interest as specified by the LLC Agreement.

Management Incentive Units

We have an Incentive Pool Plan (the "Plan"), whereby we may grant up to 100,000 Management Incentive Units ("MIUs") to certain key employees as an additional form of compensation. Each MIU entitles the holder to share, in accordance with the LLC Agreement, in the allocations and distributions of any potential net proceeds received from a Vesting Event (as defined by the Plan).

The table below presents the activity and weighted average grant date fair value related to our MIUs during the years ended December 31, 2016, 2015 and 2014:

	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, January 1, 2014	76,998	$ 14.18
Granted	2,330	498.79
Vested	(15,418)	10.63
Forfeited	(85)	—
Expired	—	—
Outstanding, December 31, 2014	63,825	32.75
Granted	455	584.63
Vested	(15,752)	21.47
Forfeited	—	—
Expired	—	—
Outstanding, December 31, 2015	48,528	41.59
Granted	—	—
Vested	(15,760)	23.51
Forfeited	(800)	413.92
Expired	—	
Outstanding, December 31, 2016	31,968	$ 41.19

MIUs generally vest in equal fifteen percent increments on each of the first five anniversaries from the date of grant, with any remaining unvested MIUs vesting on the date of a Vesting Event.

Based on the characteristics of the Plan, we concluded that MIUs are considered equity-classified awards and we would record the compensation expense associated with these awards based on their grant date fair value. We calculate grant date fair value based on our total estimated value as of the grant date, which requires several estimates and assumptions including: (i) the value of our oil and natural gas assets; (ii) future oil and natural gas market prices; (iii) the success of our development plan; (iv) future well performance; (v) estimated capital expenditures; and (vi) the potential date, if any, on which a Vesting Event will occur.

As of December 31, 2016, we have not recorded any compensation expense related to MIUs. Because the MIUs vest upon the occurrence of a performance condition, which is not probable to occur and is out of our control, no compensation expense will be recognized until the occurrence of a Vesting Event. At December 31, 2016, unrecognized compensation expense associated with MIUs is approximately $2.2 million.

10. Related Party Transactions

Transactions with Vitruvian Exploration II, LLC

We are majority owned by Vitruvian Exploration II Holdings, LLC ("Holdings"), which is majority owned by Vitruvian Exploration II, LLC ("VEX II"). VEX II and Holdings are affiliates of Quantum. We routinely pay VEX II for certain operating and G&A expenses, consisting primarily of salaries and benefits, incurred on our behalf and have made advances of potential MIU distributions to VEX II Holdings.

During the years ended December 31, 2016, 2015 and 2014, VEX II incurred $16.6 million, $13.4 million and $14.4 million, respectively, of costs and expenses on our behalf. As of December 31, 2016 and 2015, our receivable from VEX II was $1.4 million and $1.0 million, respectively.

Formation of and Transactions with Vitruvian Exploration III, LLC

Vitruvian Exploration III, LLC ("VEX III"), a Delaware limited liability company, was formed on December 18, 2015 by certain members of our management team and affiliates of Quantum to engage in the acquisition, development and production of unconventional resource plays across North America.

During the years ended December 31, 2016 and 2015 we allocated $3.2 million and $0.2 million, respectively, of costs and expenses to VEX III, consisting primarily of salaries, benefits and rent expense. As of December 31, 2016 and 2015, our receivable from VEX III was $0.8 million and $0.2 million, respectively.

Transactions with Quantum

In February and March 2015, we borrowed a total of $30.0 million from Quantum. All amounts were repaid prior to December 31, 2015.

Transactions with Woodford Express, LLC ("WEX")

Woodford Express, LLC, a midstream company with natural gas assets in Oklahoma, was formed by affiliates of Quantum, and is partially owned by certain members of our management team. We have an acreage dedication agreement with WEX, whereby WEX has the right to gather and process the natural gas produced from our leases located in Grady, Stephens, and Garvin counties in Oklahoma. During the years ended December 31, 2016, 2015 and 2014, we paid $43.6 million, $12.9 million and $2.1 million, respectively, to WEX for gathering, transportation and processing fees. Additionally, during the years ended December 31, 2016, 2015 and 2014, we received payments from WEX of $1.8 million, $18.1 million and $11.7 million, respectively, for the sale of oil, natural gas and NGLs.

11. Commitments and Contingencies

Commitments

We have various commitments related to office space, office equipment and drilling rigs utilized in our exploration and development operations. Minimum future lease payments due under non-cancelable operating leases with initial or remaining terms in excess of one year at December 31, 2016 are as follows:

	Rent
2017	$ 819
2018	833
2019	843
2020	214
2021	—
Thereafter	—
Total	$2,709

Operating Leases

We lease office space in Lindsay, Oklahoma and in The Woodlands, Texas under the terms of non-cancelable leases expiring in 2017 and 2020, respectively.

Total rental expense for the years ended December 31, 2016, 2015 and 2014 was $0.9 million, $1.3 million and $1.2 million, respectively.

Delivery Commitments

In addition to the commitments above we are party to various natural gas and NGL agreements which include certain minimum volume delivery commitments. Our NGL volume commitments range from 2,000 bbls to 12,000 bbls per day over the term of the contract, which extends through 2025. Our natural gas volume commitments were 90,000 MMcfe/day in 2016, 80,000 MMcfe/day from 2017 through 2020 and 30,000 MMcfe/day from 2021 through 2025. The table below presents the aggregate amount of payments we expect to make under these various contracts:

	Payments Due by Period for the Year Ending December 31,						
	2017	2018	2019	2020	2021	Thereafter	Total
				(In millions)			
Delivery commitments	$27.4	$29.4	$29.4	$30.5	$29.6	$ 97.0	$243.3

Deficiency payments of $0.9 million and $1.2 million were made during the year ended December 31, 2016 and 2015, respectively. We do not expect to incur any additional volumetric shortfall payments during the remaining contract terms of the agreement.

Performance Bonds

We have performance bonds required by various agencies as collateral against potential damage caused by our development activities. Aggregate amounts associated with our performance bonds were $2.3 million at December 31, 2016.

Contingencies

From time to time, we may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of business.

We are currently unaware of any proceedings that, in the opinion of management, will individually or in the aggregate have a material adverse effect on our financial position, results of operations or cash flows.

12. Subsequent Events

As of February 17, 2017, the date that the financial statements were issued, there have been no events subsequent to December 31, 2016, that would require additional adjustments to or disclosure in our financial statements other than the event noted below:

On February 17, 2017, we sold substantially all of the operating assets and liabilities including certain leasehold interest, mineral rights and producing wells located in the SCOOP to Gulfport Energy Corporation ("Gulfport"), an unaffiliated third-party, for a purchase price of $1.85 billion consisting of $1.35 billion in cash and $500.0 million in shares of Gulfport's common stock subject to certain adjustments. The purchase price is subject to post-closing adjustments, including adjustments for net proceeds of production after the effective date, October 1, 2016, and the satisfactory completion of title review by the purchaser.

Subsequent to the closing of this transaction, we repaid all principal and accrued interest outstanding under the Credit Facility and second lien term loan.

13. Supplemental Oil and Natural Gas Disclosures (Unaudited)

Estimated Quantities of Proved Oil and Natural Gas Reserves

All of our reserve information related to oil, natural gas and NGLs was compiled based on estimates prepared and reviewed by our engineers, each of whom we believe have the appropriate expertise and qualifications. The reserves estimation is part of our internal controls process subject to management’s annual review and approval. The reserve estimates as of December 31, 2016 were reviewed by Netherland, Sewell & Associates, Inc., our independent reserve engineers. All of the subject reserves are located in the continental United States.

Many assumptions and judgmental decisions are required to estimate reserves. Quantities reported are considered reasonable but are subject to future revisions, some of which may be substantial, as additional information becomes available. Such additional information may be gained as the result of reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other factors.

Regulations define proved oil, natural gas and NGL reserves as those quantities of oil, natural gas and NGLs that, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed oil, natural gas and NGL reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well.

Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. For oil volumes as of December 31, 2016, the average West Texas Intermediate spot price of $42.75 per barrel was adjusted for quality and transportation fees. For gas volumes as of December 31, 2016, the average Henry Hub spot price of $2.48 per MMBtu was similarly adjusted for gathering, transportation fees and distance from market. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties as of December 31, 2016, 2015 and 2014 are provided in the table below:

	2016	2015	2014
Oil (per Bbl)	$39.49	$45.43	$89.23
Natural gas (per Mcf)	2.36	2.58	4.62
NGLs (per Bbl)	15.70	13.76	31.90

The following table sets forth our net proved oil, natural gas and NGL reserves at December 31, 2016, 2015 and 2014, and the changes in net proved oil, natural gas and NGL reserves during such years:

	Natural gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total (MMcfe)(1)
Proved reserve quantities January 1, 2014	65,829	1,303	2,874	90,891
Extensions and discoveries	108,589	3,096	7,385	171,475
Production	(8,707)	(257)	(549)	(13,543)
Revisions of previous estimates	25,518	1,143	1,704	42,600
Proved reserve quantities December 31, 2014	191,229	5,285	11,414	291,423
Extensions and discoveries	497,990	17,133	28,773	773,426
Production	(21,327)	(933)	(1,297)	(34,707)
Revisions of previous estimates	(19,213)	(991)	(1,445)	(33,829)
Proved reserve quantities December 31, 2015	648,679	20,494	37,445	996,313
Extensions and discoveries	212,439	2,852	8,426	280,106
Production	(39,576)	(1,308)	(2,084)	(59,928)
Revisions of previous estimates	(19,154)	(1,762)	(4,241)	(55,170)
Proved reserve quantities December 31, 2016	802,388	20,276	39,546	1,161,321
Proved developed reserve quantities:				
December 31, 2014	70,448	2,098	4,309	108,890
December 31, 2015	167,361	5,219	9,310	254,535
December 31, 2016	228,587	5,549	11,634	331,686
Proved undeveloped reserve quantities:				
December 31, 2014	120,781	3,187	7,105	182,533
December 31, 2015	481,318	15,275	28,135	741,778
December 31, 2016	573,801	14,727	27,912	829,635
Total proved:				
December 31, 2014	191,229	5,285	11,414	291,423
December 31, 2015	648,679	20,494	37,445	996,313
December 31, 2016	802,388	20,276	39,546	1,161,321

(1) May not sum or recalculate due to rounding

The changes in proved reserves during 2016, 2015 and 2014 are comprised of the following items:

Revision of previous estimates

The downward revision of previous estimates of 55,170 MMcfe and 33,829 MMcfe during 2016 and 2015, respectively, is attributable to decreased commodity prices, which decreased the useful lives of the wells, decreasing the ultimate reserves recovered. The upward revision of previous estimates of 42,600 MMcfe during 2014 is primarily attributable to well performance exceeding previous estimates.

Extensions and discoveries

Extensions and discoveries of 280,106 MMcfe, 773,426 MMcfe and 171,475 MMcfe during 2016, 2015 and 2014, respectively, are comprised of extensions and discoveries as a result of continuous drilling in the SCOOP play.

Since June 2013 when we began operation of our first drilling rig, we have generally averaged a four-rig drilling program, and we are currently operating four rigs, all of which are drilling Woodford and Springer shale horizontal wells. During this time, our operated horizontal producing wells increased from two wells as of January 1, 2014 to 50 wells as of December 31, 2016 driving a corresponding growth in proved reserves.

Standardized Measure

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves as of the years ended December 31, 2016, 2015 and 2014 are shown in the table below. Since we are not a taxpaying entity for federal income tax purposes, we did not provide for any future income tax expense in our calculation.

	2016	2015	2014
Future cash inflows	$ 3,477,982	$ 3,280,608	$1,796,635
Future production costs	(1,543,393)	(1,281,335)	(483,549)
Future development costs	(766,513)	(737,545)	(241,783)
Future income tax expenses	—	—	—
Future net cash flows	1,168,076	1,261,728	1,071,303
10% annual discount for estimated timing of cash flows	(784,069)	(812,530)	(609,218)
Standardized measure of discounted future net cash flows	$ 384,007	$ 449,198	$ 462,085

Changes in Standardized Measure

The following are the principal sources of change in the standardized measure of discounted future net cash flows for the years shown:

	2016	2015	2014
Standardized measure January 1,	$ 449,198	$ 462,085	$135,056
Sale of oil and natural gas produced, net of production costs	(123,480)	(78,041)	(60,407)
Changes in prices, net of production costs	(81,801)	(338,361)	14,763
Extensions, discoveries and enhanced production	72,595	375,251	290,032
Change in estimated future development costs	92,273	71,109	(34,317)
Development costs incurred, previously estimated	30,199	8,992	9,960
Revision of quantity estimates	(34,504)	(25,485)	84,061
Accretion of discount	44,920	46,209	13,506
Changes in timing of estimated cash flows and other	(65,393)	(72,561)	9,431
Standardized measure December 31,	$ 384,007	$ 449,198	$462,085

Per Unit Sales Price and Costs

The following table presents per unit realized price and costs of our oil, natural gas and NGLs for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
Average unit sales price excluding the effects of hedging:			
Oil (per Bbl)	$37.92	$42.85	$89.76
Natural gas (per Mmcf)	2.44	2.52	4.37
NGLs (per Bbl)	13.95	13.64	31.40
Net equivalent thousand cubic feet of gas (6:1)	$ 2.93	$ 3.21	$ 5.79
Average unit production costs:			
Net equivalent thousand cubic feet of gas (6:1)	$ 0.87	$ 0.96	$ 1.33

Exhibit 99.2

GULFPORT ENERGY CORPORATION
Summary Unaudited Pro Forma Consolidated Financial Information

The following unaudited pro forma consolidated financial information is presented to illustrate the effect of Gulfport's (or our) purchase of oil and gas assets from Vitruvian for cash and shares of our common stock to be issued to Vitruvian in the Acquisition. The unaudited pro forma balance sheet as of December 31, 2016 is based on our historical financial statements as of December 31, 2016 after giving effect to the transaction as if it had occurred on December 31, 2016. The unaudited pro forma statements of operations for the fiscal year ended December 31, 2016 are based on the historical financial statements for such period after giving effect to the transaction as if it had occurred on January 1, 2016. The unaudited pro forma financial information should be read in conjunction with our historical consolidated financial statements and notes thereto included in our reports filed with the SEC under the Securities Exchange Act of 1934, as amended.

The preparation of the unaudited pro forma consolidated financial information is based on financial statements prepared in accordance with accounting principles generally accepted in the United States of America. These principles require the use of estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Actual results could differ from those estimates.

The unaudited pro forma consolidated financial information is provided for illustrative purposes only and does not purport to represent what our actual results of operations or our financial position would have been had the transactions occurred on the respective dates assumed, nor is it indicative of our future operating results or financial position. The pro forma adjustments reflected in the accompanying unaudited pro forma consolidated financial information reflect estimates and assumptions that our management believes to be reasonable.

GULFPORT ENERGY CORPORATION
UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET
At December 31, 2016

	Gulfport Historical	Vitruvian Historical	Pro Forma Adjustments	Gulfport Combined
		(in thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 1,275,875	$ 2,632	$(1,171,725) (1), (2)	$ 106,782
Restricted cash	185,000	—	(185,000) (2)	—
Accounts receivable - oil and gas	136,761	38,304	(38,304) (1)	136,761
Accounts receivable - related parties	16	2,187	(2,187) (1)	16
Prepaid expenses and other current assets	7,639	12,834	(12,834) (1)	7,639
Short-term derivative instruments	3,488	2,275	(2,275) (1)	3,488
Total current assets	1,608,779	58,232	(1,412,325)	254,686
Property and equipment:				
Oil and natural gas properties, full-cost accounting, $1,580,305, $368,238 and $3,058,815 excluded from amortization as reported and pro forma as adjusted, respectively	6,071,920	1,252,966	569,524 (2)	7,894,410
Other property and equipment	68,986	17,199	(17,199) (1)	68,986
Accumulated depletion, depreciation, amortization and impairment	(3,789,780)	(498,256)	498,256 (1)	(3,789,780)
Property and equipment, net	2,351,126	771,909	1,050,581	4,173,616
Other assets				
Equity investments	243,920	—	—	243,920
Deferred financing costs	—	1,386	(1,386) (1)	—
Long-term derivative instruments	5,696	—	—	5,696
Deferred tax asset	4,692	—	—	4,692
Other assets	8,932	28	(28) (1)	8,932
Total other assets	263,240	1,414	(1,414)	263,240
Total assets	$ 4,223,145	$ 831,555	$ (363,158)	$ 4,691,542
Liabilities and Stockholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$ 265,124	$ 69,637	$ (69,637) (1)	$ 265,124
Asset retirement obligation - current	195	—	—	195
Short-term derivative instruments	119,219	15,384	(15,384) (1)	119,219
Current maturities of long-term debt	276	221,500	(221,500) (1)	276
Total current liabilities	384,814	306,521	(306,521)	384,814
Long-term derivative instrument	26,759	6,443	(6,443) (1)	26,759
Asset retirement obligation - long-term	34,081	6,647	(2,889) (1), (2)	37,839
Long-term debt, net of current maturities	1,593,599	98,731	(98,731) (1)	1,593,599
Total liabilities	2,039,253	418,342	(414,584)	2,043,011
Commitments and contingencies				
Preferred stock, $.01 par value				
Stockholders' equity:				
Common stock - $.01 par value	1,588	—	239 (2)	1,827
Paid-in capital	3,946,442	—	464,400 (2)	4,410,842
Accumulated other comprehensive loss	(53,058)	—	—	(53,058)
Retained (deficit) earnings	(1,711,080)	413,213	(413,213) (1)	(1,711,080)
Total stockholders' equity	2,183,892	413,213	51,426	2,648,531
Total liabilities and stockholders' equity	$ 4,223,145	$ 831,555	$ (363,158)	$ 4,691,542

GULFPORT ENERGY CORPORATION
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2016

	Gulfport Historical	Vitruvian Historical	Vitruvian Acquisition Adjustments	Pro Forma
	(in thousands)			
Revenues:				
Gas sales	$ 420,128	$ 96,741	$ —	$ 516,869
Oil and condensate sales	81,173	49,585	—	130,758
Natural gas liquids sales	59,115	29,070	—	88,185
Net loss on gas, oil and NGL derivatives	(174,506)	—	(38,209) (3)	(212,715)
	385,910	175,396	(38,209)	523,097
Costs and expenses:				
Lease operating expenses	68,877	6,819	—	75,696
Production taxes	13,276	3,055	—	16,331
Midstream gathering and processing	165,972	42,042	—	208,014
Depreciation, depletion, and amortization	245,974	64,751	34,396 (4)	345,121
Impairment of oil and gas properties	715,495	190,532	—	906,027
General and administrative	43,409	17,553	(13,188) (5)	47,774
Accretion expense	1,057	—	337 (6)	1,394
	1,254,060	324,752	21,545	1,600,357
LOSS FROM OPERATIONS:	(868,150)	(149,356)	(59,754)	(1,077,260)
OTHER (INCOME) EXPENSE:				
Interest expense	63,530	—	—	63,530
Interest income	(1,230)	—	—	(1,230)
Insurance proceeds	(5,718)	—	—	(5,718)
Loss on debt extinguishment	23,776	—	—	23,776
Gain Loss on derivative contracts, net	—	38,209	(38,209) (3)	—
Loss from equity method investments	33,985	—	—	33,985
Loss on sale of assets	—	85	—	85
Other expense	129	—	—	129
	114,472	38,294	(38,209)	114,557
LOSS BEFORE INCOME TAXES	(982,622)	(187,650)	(21,545)	(1,191,817)
INCOME TAX (BENEFIT) EXPENSE	(2,913)	49	1,528 (7)	(1,336)
NET LOSS	$ (979,709)	$(187,699)	$ (23,073)	$ (1,190,481)
NET LOSS PER COMMON SHARE:				
Basic	$ (7.97)			$ (8.11)
Diluted	$ (7.97)			$ (8.11)
Weighted average common shares outstanding - Basic	122,952,866		23,852,117	146,804,983
Weighted average common shares outstanding - Diluted	122,952,866		23,852,117	146,804,983

Notes:

(1) These adjustments reflect the elimination of certain assets and liabilities that were not part of the assets acquired or liabilities assumed in the Vitruvian Acquisition.

(2) The Vitruvian Acquisition qualified as a business combination for accounting purposes and, as such, the Company estimated the fair value of the acquired properties as of the February 17, 2017 acquisition date. The fair value of the consideration transferred at the closing date of the Vitruvian Acquisition is allocated in the following preliminary purchase price allocation:

	(In thousands)
Consideration:	
Cash	$ 1,354,093
Fair value of Gulfport's common stock issued(i)	464,639
Total Consideration	$ 1,818,732
Estimated Fair Value of Assets Acquired and Liabilities Assumed:	
Oil and natural gas properties	
Proved properties	$ 341,144
Unproved properties	1,481,346
Asset retirement obligations	(3,758)
	$ 1,818,732

(i) 23,852,117 shares of Gulfport common stock at $19.48 per share (closing price at February 17, 2017)

Upon closing of the Vitruvian Acquisition, the Company transferred $1.35 billion in cash, subject to certain adjustments, and approximately 23.9 million shares of the Company's common stock (of which approximately 5.2 million shares are subject to the indemnity escrow). The value of the purchase price consideration may change based upon the finalization of purchase price adjustments and finalization of the Company's valuation of the assets acquired and liabilities assumed.

The initial purchase price of $1.85 billion consisted of cash consideration of $1.35 billion and equity consideration of $500.0 million (23,852,117 shares of Gulfport common stock based on equity offering price of $20.96 on December 15, 2016). The decrease in the price of Gulfport's common stock from $20.96 on December 15, 2016 to $19.48 on February 17, 2017 resulted in a decrease to the fair value of the total consideration paid of approximately $35.3 million, which resulted in a closing date fair value lower than the initial purchase price.

(3) The following adjustment has been made to the presentation of Vitruvian historical amounts to conform with the Company's presentation.

a. Reclassification of $38,209 of loss on derivative contracts, net to net loss on gas, oil and NGL derivatives.

(4) To adjust historical depletion expense associated with the oil and gas properties acquired. The pro forma adjustment includes adjusting the acquired oil and natural gas properties to their fair value calculated as of the acquisition date and applying the full cost method of accounting.
(5) Reflects adjustment for historical general and administrative costs not acquired.
(6) To adjust historical accretion expense associated with the oil and gas properties acquired.
(7) To adjust historical income tax expense for the oil and gas properties acquired.