Liberty Tax, Inc.
Form EFFECT
December 05, 2014

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The total volume hedged for 2016 represented approximately 77% of our total sales volumes for the year. The total volume hedged for 2015 represented approximately 46% of our total sales volumes for the year. The total volume hedged for 2014 represented approximately 62% of our total sales volumes for the year.

From 2015 to 2016, our net equivalent gas production increased 32% from 200,089 MMcfe to 263,430 MMcfe primarily as a result of the continued development of our Utica Shale acreage. From 2014 to 2015, our net equivalent gas production increased 128% from 87,719 MMcfe to 200,089 MMcfe primarily as a result of the development of our Utica Shale acreage. We currently estimate that our 2017 production will be between 381,425 and 401,500 MMcfe. However, our actual production may be different due to changes in our currently anticipated drilling and recompletion activities, changing economic climate, adverse weather conditions or other unforeseen events. See Item 1A. "Risk Factors."

Comparison of the Years Ended December 31, 2016 and December 31, 2015

We reported a net loss of $979.7 million for the year ended December 31, 2016 as compared to a net loss of $1.2 billion for the year ended December 31, 2015. This decrease in period-to-period net loss was due primarily to a $724.9 million decrease of impairment of oil and gas properties, a $91.7 million decrease in depreciation, depletion and amortization expense and a $72.1 million decrease in loss from equity method investments, partially offset by a $323.1 million decrease in oil and gas revenues, a $27.4 million increase in midstream gathering and processing expenses, a $23.8 million loss on debt extinguishment and a $253.1 million decrease in income tax benefit for the year ended December 31, 2016, as compared to the year ended December 31, 2015.

Oil and Gas Revenues. For the year ended December 31, 2016, we reported oil and natural gas revenues of $385.9 million as compared to oil and natural gas revenues of $709.0 million during 2015. This $323.1 million, or 46%, decrease in revenues was primarily attributable to the following:

- A $378.0 million decrease in natural gas and oil sales due to an unfavorable change in gains and losses from derivative instruments. Of the total change, $407.0 million was due to unfavorable changes in the fair value of our open derivative positions in each period and $29.0 million was due to a favorable change in settlements related to our derivative positions.
- A $95.4 million increase in gas sales without the impact of derivatives due to a 46% increase in gas sales volumes, partially offset by an 11% decrease in natural gas market prices.
- A $41.4 million decrease in oil and condensate sales without the impact of derivatives due to a 27% decrease in oil and condensate sales volumes and a 10% decrease in oil and condensate market prices.
- A $1.0 million increase in natural gas liquids sales without the impact of derivatives due to a 17% increase in natural gas liquids market prices, partially offset by a 13% decrease in natural gas liquids sales volumes.

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes decreased to $68.9 million for the year ended December 31, 2016 from $69.5 million for the year ended December 31, 2015. This decrease was mainly the result of an decrease in expenses related to contract labor and field supervision, field telemetry, facility repairs and maintenance and water disposal, partially offset by increases in water hauling, compression and ad valorem taxes.

Production Taxes. Production taxes decreased to $13.3 million for the year ended December 31, 2016 from $14.7 million for 2015. This decrease was primarily related to changes in our product mix and production location, as well as a decrease in commodity prices.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by $27.4 million to $166.0 million for the year ended December 31, 2016 from $138.6 million for 2015. This increase was primarily the result of midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2016 and 2015 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense decreased to $246.0 million for the year ended December 31, 2016, and consisted of $243.1 million in depletion of oil and natural gas properties and $2.9 million in depreciation of other property and equipment, as compared to total DD&A expense of $337.7 million for 2015. This decrease was due to a decrease in our full cost pool as a result of our 2015 and 2016 ceiling test

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impairments and an increase in our total proved reserves volume used to calculate our total DD&A expense, partially offset by an increase in our production.

General and Administrative Expenses. Net general and administrative expenses increased to $43.4 million for the year ended December 31, 2016 from $42.0 million for the year ended December 31, 2015. This $1.4 million increase was due to an increase in salaries and benefits resulting from an increased number of employees, increases in fees for tax services, bank service charges, computer support, legal fees and consulting services, partially offset by a decrease in stock compensation expense.

Accretion Expense. Accretion expense increased to $1.1 million for the years ended December 31, 2016 from $0.8 million for the year ended December 31, 2015.

Interest Expense. Interest expense increased to $63.5 million for the year ended December 31, 2016 from $51.2 million for the year ended December 31, 2015 due primarily to the issuance of $350.0 million of 6.625% Senior Notes due 2023 on April 21, 2015 and the issuance of $600.0 million of the 2025 Notes on December 21, 2016, partially offset by our repurchase or redemption of the 2020 Notes in October 2016 with the net proceeds from our issuance of $650.0 million of the 2024 Notes. Total weighted debt outstanding under our revolving credit facility was $0.2 million for the year ended December 31, 2016 as compared to $46.6 million outstanding under such facility for 2015. Additionally, we capitalized approximately $8.7 million and $13.3 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2016 and December 31, 2015, respectively. This decrease in capitalized interest in the 2016 period was the result of changes to our development plan for our oil and natural gas properties.

Income Taxes. As of December 31, 2016, we had a net operating loss carry forward of approximately $463.1 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2016, a valuation allowance of $645.8 million was established against the net deferred tax asset, with the exception of certain state NOLs and AMT credits that we expect to be able to utilize with net operating loss carrybacks and tax planning in the amount of $4.7 million. We recognized an income tax benefit from continuing operations of $2.9 million for the year ended December 31, 2016.

Comparison of the Years Ended December 31, 2015 and December 31, 2014

We reported a net loss of $1.2 billion for the year ended December 31, 2015 as compared to net income of $246.9 million for the year ended December 31, 2014. This decrease in period-to-period net income was due primarily to to an impairment charge of $1.4 billion, a $17.3 million increase in lease operating expenses, a $74.1 million increase in midstream gathering and processing expenses, a $3.7 million increase in general and administrative expenses, a $245.5 million decrease in income from equity method investments and a $27.2 million increase in interest expense, partially offset by a $38.2 million increase in oil and natural gas revenues, $10.0 million of insurance proceeds and a $409.3 million decrease in income tax expense for the year ended December 31, 2015, as compared to the year ended December 31, 2014. In addition, our 2014 net income included $79.7 million of income recognized from our equity method investment in Diamondback, $84.8 million of income recognized from our equity method investment in Blackhawk and $84.5 million of income recognized from our contribution of investments to Mammoth.

Oil and Gas Revenues. For the year ended December 31, 2015, we reported oil and natural gas revenues of $709.0 million as compared to oil and natural gas revenues of $670.8 million during 2014. This $38.2 million, or 6%, increase in revenues was primarily attributable to the following:

- A $94.2 million increase in natural gas and oil sales due to favorable change in gains and losses from derivative instruments. Of the total change, $131.7 million was due to a favorable change in settlements related to our derivative positions and $37.5 million was due to unfavorable changes in the fair value of our open derivative positions in each period.
- A $98.6 million increase in gas sales without the impact of derivatives due to a 163% increase in gas sales volumes, partially offset by a 45% decrease in natural gas market prices.

- a $118.6 million decrease in oil and condensate sales without the impact of derivatives due to a 53% decrease in oil and condensate market prices, partially offset by an 8% increase in oil and condensate sales volumes.

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- A $36.0 million decrease in natural gas liquids sales without the impact of derivatives due to a 71% decrease in natural gas liquids market prices, partially offset by a 116% increase in natural gas liquids sales volumes.

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $69.5 million for the year ended December 31, 2015 from $52.2 million for the year ended December 31, 2014. This increase was mainly the result of an increase in expenses related to property taxes, contract labor and field supervision, field telemetry, location repair, rentals, facility repairs and maintenance and water hauling and disposal due to our increased production in the Utica Shale.

Production Taxes. Production taxes decreased to $14.7 million for the year ended December 31, 2015 from $24.0 million for 2014. This decrease was primarily related to changes in our product mix and production location, as well as the decline in commodity prices.

Midstream Gathering and Processing Expenses. Midstream gathering and processing expenses increased by $74.1 million to $138.6 million for the year ended December 31, 2015 from $64.5 million for 2014. This increase was primarily the result of midstream expenses related to our increased production volumes in the Utica Shale resulting from our 2015 and 2014 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $337.7 million for the year ended December 31, 2015, and consisted of $335.3 million in depletion of oil and natural gas properties and $2.4 million in depreciation of other property and equipment, as compared to total DD&A expense of $265.4 million for 2014. This increase was due to an increase in our full cost pool as a result of our capital activities as well as an increase in our production, partially offset by an increase in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $42.0 million for the year ended December 31, 2015 from $38.3 million for the year ended December 31, 2014. This $3.7 million increase was due to an increase in salaries and benefits resulting from an increased number of employees, increases in fees for audit services, bank service charges, computer support and travel expense, partially offset by decreases in stock compensation expense, consulting expense, legal expense and franchise taxes and an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense remained relatively flat at $0.8 million for the years ended December 31, 2015 and 2014.

Interest Expense. Interest expense increased to $51.2 million for the year ended December 31, 2015 from $24.0 million for the year ended December 31, 2014 due primarily to the issuance of $300.0 million of additional 7.75% Senior Notes due 2020 on August 18, 2014, the issuance of $350.0 million of 6.625% Senior Notes due 2023 on April 21, 2015 and increased borrowings under our revolving credit facility during 2015. Total weighted debt outstanding under our revolving credit facility was $46.6 million for the year ended December 31, 2015 as compared to $22.8 million outstanding under such facility for 2014. Additionally, we capitalized approximately $13.3 million and $9.7 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2015 and December 31, 2014, respectively. This increase in capitalized interest in the 2015 period was the result of an increase in our undeveloped oil and natural gas properties.

Income Taxes. As of December 31, 2015, we had a net operating loss carry forward of approximately $132.0 million, in addition to numerous temporary differences, which gave rise to a net deferred tax asset as a result of recording a full cost ceiling impairment of $1.4 billion. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2015, a valuation allowance of $281.8 million was established against the net deferred tax asset, with the exception of certain state NOL's and AMT credits that we expect to be able to utilize with net operating loss carrybacks and tax planning in the amount of $24.2 million. We recognized an income tax benefit from continuing operations of $256.0 million for the year ended December 31, 2015.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our credit facility and issuances of equity and debt securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and natural gas production.

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Net cash flow provided by operating activities was $337.8 million for the year ended December 31, 2016 as compared to net cash flow provided by operating activities of $322.2 million for 2015. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 13% increase in net revenues after giving effect to settled derivative instruments, partially offset by an increase in our operating expenses.

Net cash flow provided by operating activities was $322.2 million for the year ended December 31, 2015, as compared to net cash flow provided by operating activities of $409.9 million for 2014. This decrease was primarily the result of a 54% decrease in net realized Mcfe prices and increases in our operating expenses due to our increased activity in the Utica Shale, partially offset by an increase in cash receipts from our oil and natural gas purchasers due to a 128% increase in our net Mcfe production.

Net cash used in investing activities for the year ended December 31, 2016 was $905.6 million as compared to $1.6 billion for 2015. During the year ended December 31, 2016, we spent $724.9 million in additions to oil and natural gas properties, of which $346.7 million was spent on our 2016 drilling and recompletion programs, $145.3 million was spent on expenses attributable to the wells spud, completed and recompleted during 2015, $4.3 million was spent on facility enhancements, $3.7 million was spent on plugging costs, $154.5 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, with the remainder attributable mainly to future location development and capitalized general and administrative expenses. In addition, $15.5 million was invested in Grizzly and $11.0 million was invested in Strike Force. We did not make any material investments in our our other equity investments during the year ended December 31, 2016. We also received approximately $45.8 million from the sale of oil and gas properties, primarily the sale of non-producing leasehold acreage in the non-core area of our Utica acreage and spent $185.0 million to fund the escrow deposit for our pending acquisition. During the year ended December 31, 2016, we used cash from operations and proceeds from our 2015 and 2016 equity and debt offerings for our investing activities.

Net cash used in investing activities for the year ended December 31, 2015 was $1.6 billion as compared to $1.1 billion for 2014. During the year ended December 31, 2015, we spent $1.6 billion in additions to oil and natural gas properties, of which $217.6 million was spent on our 2015 drilling and recompletion programs, $512.0 million was spent on expenses attributable to the wells drilled and recompleted during 2014, $705.1 million was spent on the AEU and Paloma acquisitions, $9.9 million was spent on facility enhancements, $3.1 million was spent on plugging costs and $96.2 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $14.5 million was invested in Grizzly. We did not make an material investments in our other equity investments during the year ended December 31, 2015. During the year ended December 31, 2015, we used cash from operations and proceeds from our 2014 equity and 2015 debt offerings for our investing activities.

Net cash provided by financing activities for the year ended December 31, 2016 was $1.7 billion as compared to net cash provided by financing activities of $1.2 billion for 2015. The 2016 amount provided by financing activities is primarily attributable to the net proceeds of $1.2 billion from our 2016 debt offerings. partially offset by the redemption of our 2020 Notes, and net proceeds of $1.1 billion from our 2016 equity offerings.

Net cash provided by financing activities for the year ended December 31, 2015 was $1.2 billion as compared to $410.2 million for 2014. The 2015 amount provided by financing activities is primarily attributable to the gross proceeds of $350.0 million from our 2015 debt offering and net proceeds of $981.5 million from our 2015 equity offerings.

Credit Facility. We have entered into a senior secured revolving credit facility, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The credit agreement provides for a maximum facility amount of $1.5 billion and matures on December 13, 2021. As of December 31, 2016, we had no balance outstanding under our revolving credit facility and total funds available for borrowing, after giving effect to an aggregate of $209.7 million of letters of credit, were $490.3 million. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Advances under our revolving credit facility may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.00% to 2.00%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its "prime rate," and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.00% to 3.00%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or other service that displays an average

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London interbank offered rate as administered by ICE Benchmark Administration (or any other person that takes over the administration of such rate) for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the "London Interbank Offered Rate" for deposits in U.S. dollars.

Our revolving credit facility contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries' ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in our revolving credit facility. Our revolving credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or non-cash revenue or expense attributable to minority investment plus without duplication and, in the case of expenses, to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) exploration costs deducted in determining net income under successful efforts accounting, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings (provided that expenses related to any unsuccessful dispositions will be limited to $3.0 million in the aggregate) for a twelve-month period may not be greater than 4.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at December 31, 2016.

Senior Notes. In October 2012, December 2012 and August 2014, we issued an aggregate of $600.0 million in principal amount of our 7.75% senior notes due 2020 which were subsequently exchanged for substantially identical senior notes registered under the Securities Act. These senior notes, which were issued under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, were treated as a single class of debt securities under the senior note indenture and are referred to collectively as the 2020 Notes. Interest on the 2020 Notes accrued at a rate of 7.75% per annum on the outstanding principal amount payable semi-annually on May 1 and November 1 of each year. The 2020 Notes were senior unsecured obligations and ranked equally in the right of payment with all of our other senior indebtedness and were senior in right of payment to any of our future subordinated indebtedness. We had the option to redeem some or all of the 2020 Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, we had the option to redeem the 2020 Notes at a price equal to 100% of the principal amount plus a "make-whole" premium. In addition, prior to November 1, 2015, we had the option to redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the 2020 Notes initially issued remained outstanding immediately after such redemption.

On October 6, 2016, we commenced a cash tender offer to purchase any and all of the 2020 Notes, which tender offer expired on October 13, 2016 and settled on October 14, 2016. Holders of the 2020 Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2020 Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,042 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date. An aggregate of $403.5 million in principal amount of the 2020 Notes was validly tendered in the tender offer. The remaining 2020 Notes that were not tendered in the tender offer were redeemed by us. The redemption payment included approximately $196.5 million in aggregate principal amount at a redemption price of 103.875% of the principal amount of the redeemed 2020 Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 14, 2016, the indenture governing the 2020 Notes was fully satisfied and discharged. The cash tender offer for the 2020 Notes and redemption of the remaining 2020 Notes were funded with the net proceeds from the offering of the 2024 Senior Notes (as discussed below) and cash on hand.

In April 2015, we issued an aggregate of $350.0 million in principal amount of our 6.625% senior notes due 2023 under a new indenture, dated as of April 21, 2015, among us, our subsidiary guarantors and Wells Fargo Bank, N.A., as trustee. Interest on these senior notes, which we refer to as the 2023 Notes, accrues at a rate of 6.625% per annum on the outstanding principal amount thereof from April 21, 2015, payable semi-annually on May 1 and November 1 of each year, commencing on November 1, 2015. The 2023 Notes will mature on May 1, 2023 and are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness, including the 2020 Notes, and senior in right of payment to any of our future subordinated indebtedness. We may redeem some or all of the 2023 Notes at any time on or after May 1, 2018, at the

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redemption prices listed in the indenture relating to the 2023 Notes. Prior to May 1, 2018, we may redeem all or a portion of the 2023 Notes at a price equal to 100% of the principal amount of the 2023 Notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to May 1, 2018, we may redeem the 2023 Notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2023 Notes issued prior to such date at a redemption price of 106.625%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

On October 14, 2016, we issued the 2024 Notes in aggregate principal amount of $650.0 million. The 2024 Notes were issued under an indenture, dated as of October 14, 2016, among us, the subsidiary guarantors party thereto and the senior note indenture, to qualified institutional buyers pursuant to Rule 144A under the Securities Act, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under this indenture, interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof from October 14, 2016, payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2017. The 2024 Notes will mature on October 15, 2024. We received approximately $638.9 million in net proceeds from the offering of the 2024 Notes, which was used, together with cash on hand, to purchase the outstanding 2020 Notes in a concurrent cash tender offer, to pay fees and expenses thereof, and to redeem any of the 2020 Notes that remained outstanding after the completion of the tender offer.

On December 21, 2016, we issued $600.0 million in aggregate principal amount of 2025 Notes. The 2025 Notes were issued under an indenture, dated as of December 21, 2016, among us, the subsidiary guarantors party thereto and the senior note indenture, to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under this indenture, interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from December 21, 2016, payable semi-annually on May 15 and November 15 of each year, commencing on May 15, 2017. The 2025 Notes will mature on May 15, 2025. We received approximately $590.8 million in net proceeds from the offering of the 2025 Notes, which we intend to use, together with the net proceeds from our December 2016 offering of common stock and cash on hand, to fund the cash portion of the purchase price for the Pending Acquisition with Vitruvian.

All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the 2023 Notes, 2024 Notes, and 2025 Notes, provided, however, that the 2023 Notes, 2024 Notes, and 2025 Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of our future unrestricted subsidiaries. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The 2023 Notes, 2024 Notes, and 2025 Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our amended and restated credit agreement) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the 2023 Notes, 2024 Notes, and 2025 Notes.

If we experience a change of control (as defined in the senior note indentures relating to the 2023 Notes, 2024 Notes, and 2025 Notes), we will be required to make an offer to repurchase the 2023 Notes, 2024 Notes, and 2025 Notes and at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. If we sell certain assets and fail to use the proceeds in a manner specified in our senior note indentures, we will be required to use the remaining proceeds to make an offer to repurchase the 2023 Notes, 2024 Notes, and 2025 Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. The senior note indentures relating to the 2023 Notes, 2024 Notes, and 2025 Notes contain certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

Under the indenture relating to the 2023 Notes, 2024 Notes and 2025 Notes, certain of these covenants are subject to termination upon the occurrence of certain events, including in the event the 2023 Notes, 2024 Notes, and 2025 Notes are ranked as "investment grade."

In connection with the offerings of the 2024 Notes and the 2025 Notes, we and our subsidiary guarantors entered into registration rights agreements with the representatives of the initial purchasers pursuant to which we agreed to file a registration statement with respect to an offer to exchange the 2024 Notes and the 2025 Notes for new issues of substantially identical debt securities registered under the Securities Act.

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Construction Loan. On June 4, 2015, we entered into a construction loan agreement, or the construction loan, with InterBank for the construction of our new corporate headquarters in Oklahoma City. The construction loan allows for maximum principal borrowings of $24.5 million and requires us to fund 30% of the cost of the construction before any funds can be drawn, which occurred in January 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum and is payable on the last day of the month through May 31, 2017. Monthly interest and principal payments are due beginning June 30, 2017, with the final payment due June 4, 2025. As of December 31, 2016, the total borrowings under the construction loan were approximately $21.0 million.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions primarily in the Utica Shale, and for investments in entities that may provide services to facilitate the development of our acreage. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, (2) pursue acquisition and disposition opportunities and (3) pursue business integration opportunities.

Of our net reserves at December 31, 2016, 63.0% were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

During 2016, we spud 50 gross (43.5 net) and commenced sales from 54 gross (40.2 net) wells in the Utica Shale for a total cost of approximately $330.1 million. In addition, 35 gross (6.9 net) wells were drilled and 25 gross (6.3 net) wells were turned to sales by other operators on our Utica Shale acreage during 2016 for a total cost to us of approximately $19.3 million. We currently expect to drill 87 to 97 gross (67 to 74 net) horizontal wells and commence sales from 72 to 80 gross (61 to 67 net) wells on our Utica Shale acreage. As of February 10, 2017, we had six operated horizontal rigs drilling in the play. We also anticipate an additional 30 to 34 gross (10 to 11 net) horizontal wells will be drilled, and sales commenced from 42 to 46 gross (nine to 10 net) horizontal wells, on our Utica Shale acreage by other operators. We currently anticipate our 2017 capital expenditures to be $645.0 million to $690.0 million related to our operated and non-operated Utica Shale activities.

During 2017, we currently expect to drill 19 to 21 gross (16 to 18 net) wells and commence sales from 17 to 19 gross (14 to 16 net) wells on the acreage subject to our pending SCOOP acquisition. We also anticipate ten to 12 gross (one to two net) wells will be drilled, and sales commenced from ten to 12 gross (one to two net) wells on this SCOOP acreage by other operators. We currently expect to spend $170.0 million to $190.0 million on these activities for our pending SCOOP acreage during 2017.

In addition, we currently expect to spend an aggregate of $110.0 million to $120.0 million in 2017 for acreage expenses in the Utica Shale and SCOOP.

During 2016, we recompleted 54 existing wells and spud no new wells for a total cost of approximately $11.7 million at our WCBB field. In our Hackberry fields, in 2016, we recompleted 23 existing wells and spud no new wells for a total cost of approximately $4.4 million. We currently expect to spend $30.0 million to $35.0 million in 2017 to drill 12 to 15 gross and net wells and perform recompletion activities in Southern Louisiana.

During 2016, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2017.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2016, our net investment in Grizzly was approximately $45.2 million. Our capital requirements in 2016 for Grizzly were approximately $15.5 million. Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which Grizzly paid the outstanding balance in full in July 2016. Gulfport paid its share of this amount on June 30, 2016. We do not currently anticipate any material capital expenditures in 2017 related to Grizzly's activities.

We had no material capital expenditures during the during the year ended December 31, 2016 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2017.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. See Item 1. "Business–Our Equity Investments" and Note 4 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments. During the years ended December 31, 2016 and 2015, we did not make any additional investments in these

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entities, and we do not currently anticipate any capital expenditures related to these entities in 2017. We are currently evaluating strategic alternatives with respect to some of these oil field service entities. In the fourth quarter of 2014, we contributed our investments in Stingray Pressure, Stingray Logistics, Bison and Muskie to Mammoth, in exchange for a 30.5% limited partner interest in this newly formed limited partnership. On October 19, 2016, Mammoth Energy completed its IPO of 7,750,000 shares of its common stock at a public offering price of $15.00 per share, of which 7,500,000 shares were sold by Mammoth Energy and 250,000 shares were sold by certain selling stockholders, including 76,250 shares sold by us for which we received net proceeds of $1.1 million. Prior to the completion of the IPO, we were issued 9,150,000 shares of Mammoth Energy common stock in return for the contribution of our 30.5% interest in Mammoth. Following the IPO, we owned an approximate 24.2% interest in Mammoth Energy.

In February 2016, we, through Midstream Holdings, entered into an agreement with Rice to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio, which we refer to as the dedicated areas. We own a 25% interest in the newly formed entity Strike Force, and Rice acts as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is underway, is providing gathering services for an increasing number of Gulfport operated wells and connectivity of existing dry gas gathering systems and interchangeability of natural gas across our firm portfolio. The first phase of the project has been completed: a lateral that connects two existing dry gas gathering systems on which we currently flow the majority of our dry gas volumes. First flow commenced through this lateral on February 1, 2016. In connection with the agreement, we contributed certain assets, including an approximately 11 mile-long, 12-inch diameter gathering line. During the year ended December 31, 2016, we also paid $11.0 million in cash calls related to Strike Force. We currently anticipate that we will also make $50.0 million to $60.0 million in cash contributions to Strike Force in 2017.

During 2015 and 2016, we continued to focus on operational efficiencies in an effort to reduce our overall well costs and deliver better results in a more economical manner, particularly in light of the continued downturn in commodity prices. We have successfully leveraged the lower commodity price environment to gain access to higher-quality equipment and superior services for reduced costs, which has contributed to increased productivity. We have also renegotiated the contracts for our horizontal drilling rigs and locked in approximately 85% of our currently anticipated drilling and completion costs for 2017. This has allowed us to secure a base level of activity for 2017, hedge against expected increases in service costs and ensure access to quality equipment and experienced crews, all of which we expect to contribute to further efficiency gains. With regard to our leasehold position, we continue to upgrade our acreage within our portfolio and focus our efforts on consolidating our premium, core position in the wet gas and dry gas windows of the Utica Shale. During the third quarter of 2016, we sold a non-core exploratory acreage position in the Utica Shale in West Virginia and re-invested the net proceeds from that sale in the dry gas window of the Utica Shale in Ohio. As a result of the continued decline in commodity prices in early 2016, our initial 2016 development plan contemplated running three rigs beginning in January 2016 and reducing activity levels throughout the year for an average of 2.5 rigs on our operated Utica Shale acreage during 2016, as compared to an average of 3.7 rigs in 2015. However, in response to the strengthening of natural gas prices later in 2016, we contracted three additional rigs, for a total of six rigs, that were phased in between September and December 2016.

Our total capital expenditures for 2017 are currently estimated to be in the range of $845.0 million to $915.0 million for drilling and completion expenditures. In addition, we currently expect to spend $110.0 million to $120.0 million in 2017 for acreage expenses, primarily lease extensions, in the Utica Shale and $50.0 million to $60.0 million to fund our investment in Strike Force. Approximately 75% of our 2017 estimated capital expenditures are currently expected to be spent in the Utica Shale. The 2017 range of capital expenditures is higher than the $549.5 million spent in 2016, primarily due to the increase in current commodity prices.

We continually monitor market conditions and are prepared to adjust our drilling program if commodity prices dictate. Currently, we believe that our cash flow from operations, cash on hand and borrowings under our loan agreements will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months, including the operations related to our pending acquisition. We believe that our strong liquidity position, hedge portfolio and conservative balance sheet position us well to react quickly to changing commodity prices and accelerate our activity within the Utica Basin from the current six rigs, or to scale back our activity, as the market conditions warrant. Notwithstanding the foregoing, in the event commodity prices decline from current levels, our capital or other costs increase, our equity investments require additional contributions and/or we pursue additional equity method investments or acquisitions, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. Further, if we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us. If the current low commodity price environment worsens, our revenues, cash flows, results of operations, liquidity and reserves may be materially and adversely affected.

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Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. During the past seven years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $26.05 per barrel, or Bbl, in February 2016 to a high of $113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.61 per MMBtu in March 2016 to a high of $7.51 per MMBtu in January 2010. During 2016, WTI prices ranged from $26.21 to $54.51 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.61 to $3.99 per MMBtu. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

See Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" for information regarding our open fixed price swaps at December 31, 2016.

Commitments

In connection with our acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2016, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2016, we have plugged 513 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2016:

	Payment due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
6.625% senior unsecured notes due 2023 (1)	$500,719	$ 23,188	$46,375	$46,375	384,781
6.000% senior unsecured notes due 2024 (2)	962,210	37,637	78,000	78,000	768,573
6.375% senior unsecured notes due 2024 (3)	921,423	33,006	76,500	76,500	735,417
Asset retirement obligations	34,276	195	599	760	32,722
Employment agreements	350	350	—	—	—
Building loan (4)	15,467	276	1,108	1,361	12,722
Firm transportation contracts	3,820,181	176,800	474,201	474,201	2,694,979
Purchase obligations (5)	91,770	52,440	39,330	—	—
Operating leases	637	583	54	—	—
Total	$6,347,033	$ 324,475	$716,167	$677,197	$4,629,194

(1) Includes estimated interest of $23.2 million due in less than one year; $46.4 million due in 1-3 years; $46.4 million due in 3-5 years and $34.8 million due thereafter.

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(2) Includes estimated interest of $37.6 million due in less than one year; $78.0 million due in 1-3 years; $78.0 million due in 3-5 years and $118.6 million due thereafter.
(3) Includes estimated interest of $33.0 million due in less than one year; $76.5 million due in 1-3 years; $76.5 million due in 3-5 years and $135.4 million due thereafter.
(4) Does not include estimated interest of $543,000 due in less than one year; $1.7 million due in 1-3 years: $1.4 million due in 3-5 years and $1.9 million due thereafter.
(5) The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2016.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which we expect to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. In July 2015, the FASB decided to defer the effective date by one year (until 2018). We are evaluating the impact of this ASU on our consolidated financial statements and, based on the continuing evaluation of our revenue streams, this ASU is not expected to have a material impact on our net income. We are still in the process of determining whether or not we will use the retrospective method or the modified retrospective approach to implementation.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40). The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for periods after December 15, 2016, with early adoption permitted. We adopted this guidance in the fourth quarter of 2016 with no impact to our consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. We adopted this ASU on January 1, 2016. As a result, certain of our equity investments were determined to be variable interest entities; however, we were not required to consolidate these investments.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. To simplify the presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. This guidance is effective for periods after December 15, 2015. We adopted this guidance on a retrospective basis in the fourth quarter of 2015 and have debt issuance costs offsetting long-term debt at December 31, 2016 and December 31, 2015 as shown in Note 6.

In September 2015, the FASB issued ASU No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if the prior-period information had been revised. The guidance is effective for periods after December 15, 2015. We adopted this guidance in the first quarter of 2016 and there was no impact to our consolidated financial statements.

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In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 705). Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We adopted this guidance in the fourth quarter of 2016 on a prospective basis; therefore, prior periods were not retrospectively adjusted.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15, 2018, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements and related disclosures; however, based on our current operating leases, it is not expected to have a material impact.

In March 2016, the FASB issued ASU No. 2016-05, Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships. The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. This guidance is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact on our consolidated financial statements. We do not believe that the adoption of this guidance will have a material impact on our consolidated financial statements as all current derivative instruments are not designated for hedge accounting.

In March 2016, the FASB issued ASU No. 2016-07, Equity Method and Joint Ventures. This guidance simplified current requirements by eliminating the need to retrospectively apply the equity method of accounting upon obtaining significant influence over an investment that it previously accounted for under the cost basis or at fair value. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We adopted this guidance in fourth quarter of 2016 and there was no impact to our consolidated financial statements as all current investments are accounted for under the equity method of accounting.

In March 2016, the FASB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This guidance is effective for periods after December 15, 2016, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In May 2016, the FASB issued ASU No. 2016-11, Revenue Recognition and Derivatives and Hedging: Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. This guidance rescinds SEC Staff Observer comments that are codified in Topic 606, Revenue Recognition, and Topic 932, Extractive Activities--Oil and Gas. This amendment is effective upon adoption of Topic 606. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and instead, requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposure, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. We are currently evaluating the impact this standard will have on our financial statements and related disclosures and do not anticipate it to have a material affect.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. This guidance provides guidance of eight specific cash flow issues. This amendment is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact of this guidance on our consolidated financial statements.

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In October 2016, the FASB issued ASU No. 2016-17, Consolidation: Interests Held through Related Parties That Are under Common Control. This guidance provides an amendment to the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. We have adopted this ASU and there was no current impact to our consolidated financial statements.
In December 2016, the FASB issued ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers. This guidance updates narrow aspects of the guidance issued in Update 2014-09. This amendment is effective for periods after December 15, 2017, with early adoption permitted. We are in the process of evaluating the impact of this ASU on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment.
These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. During the past seven years, the posted price for West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, has ranged from a low of $26.05 per barrel, or Bbl, in February 2016 to a high of $113.39 per Bbl in April 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.61 per MMBtu in March 2016 to a high of $7.51 per MMBtu in January 2010. During 2016, WTI prices ranged from $26.05 to $54.51 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.61 to $3.99 per MMBtu. If the prices of oil and natural gas continue at current levels or decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.
To mitigate the effects of commodity price fluctuations on our oil and natural gas production, we had the following open fixed price swap positions as of December 31, 2016.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2017	NYMEX Henry Hub	531,171	$ 3.17
2018	NYMEX Henry Hub	296,438	$ 3.10
2019	NYMEX Henry Hub	4,932	$ 3.37

	Location	Daily Volume (Bbls/day)	Weighted Average Price
2017	ARGUS LLS	1,748	$ 51.97

2017	NYMEX WTI	3,353	$	54.98
2018	NYMEX WTI	899	$	55.31

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	Location	Daily Volume (Bbls/day)	Weighted Average Price
2017	Mont Belvieu C3	1,630	$ 25.70
2017	Mont Belvieu C5	250	$ 49.14

We sold call options and used the associated premiums to enhance the fixed price for a portion of the fixed price natural gas swaps listed above. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, we pay our counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volumes.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2017	NYMEX Henry Hub	60,068	$ 3.12
2018	NYMEX Henry Hub	4,932	$ 2.91

For a portion of the combined natural gas derivative instruments containing fixed price swaps and sold call options, the counterparty has an option to extend the terms an additional twelve months for the period January 2018 through December 2018. These options expire in December 2017. If executed, we would have additional fixed price swaps for 30,000 MMBtu per day with the option to double at a weighted average price of $3.36 and additional short call options for 30,000 MMBtu per day with the option to double at a weighted average ceiling price of $3.36.

In addition, we have entered into natural gas basis swap positions, which settle on the pricing index to basis differential of Tetco M2 to the NYMEX Henry Hub natural gas price. As of December 31, 2016, we had the following natural gas basis swap positions for Tetco M2.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2017	Tetco M2	12,329	$ (0.59)

In January and February 2017, we entered into fixed price swaps for 2017 for approximately 23,000 MMBtu of natural gas per day at a weighted average price of $3.44 per MMbtu and for approximately 1,000 Bbls of C3 propane per day at a weighted average price of $28.56 per Bbl. For 2018, we entered into fixed price swaps for approximately 87,000 MMBtu of natural gas per day at a weighted average price of $3.19 per MMBtu. Our fixed price swap contracts are tied to the commodity prices on NYMEX for natural gas and Mont Belvieu for propane. We will receive the fixed priced amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas or Mont Belvieu for propane.

In addition, we entered into natural gas basis swap positions, which settle on the pricing index to basis differential of NPGL MC to the NYMEX Henry Hub natural gas price. In January and February 2017, we entered into natural gas basis swap positions for 2017 for approximately 38,000 MMBtu of natural gas per day at a weighted average differential of $0.26 per MMBtu. For 2018, we entered into natural gas basis swap positions for approximately 12,000 MMBtu of natural gas per day at a weighted average differential of $0.26 per MMBtu.

Under our 2017 contracts, we have hedged approximately 60% to 63% of our expected 2017 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. At December 31, 2016, we had a net liability derivative position of $136.8 million as compared to a net asset derivative position of $186.5 million as of December 31, 2015, related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $119.3 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $119.3 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the eurodollar rates are elected, the eurodollar rates. At December 31, 2016, we had no variable interest rate borrowings

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outstanding; therefore, an increase in interest rates would not have impacted our interest expense. As of December 31, 2016, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 following the signature pages of this Report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and President and our Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and President and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2016, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and President and our Chief Financial Officer have concluded that, as of December 31, 2016, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal controls over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2013 Internal Control-Integrated Framework, management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2016.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2016 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2016, as stated in their accompanying report.

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/s/ Michael G. Moore		/s/ Keri Crowell	
Name:	Michael G. Moore	Name:	Keri Crowell
Title:	Chief Executive Officer and President	Title:	Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the internal control over financial reporting of Gulfport Energy Corporation and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2016 and our report dated February 14, 2017 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP
Oklahoma City, Oklahoma
February 14, 2017

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10-Directors, Executive Officers and Corporate Governance, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 11. EXECUTIVE COMPENSATION

For information concerning Item 11-Executive Compensation, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

For information concerning Item 12-Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For information concerning Item 13-Certain Relationships and Related Transactions, and Director Independence, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For information concerning Item 14-Principal Accounting Fees and Services, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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PART IV
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES
The following documents are filed as part of this report or incorporated by reference herein:
(1) Financial Statements
Reference is made to the Index to Financial Statements appearing on Page F-1.
Reference is also made to the Financial Statements of Diamondback Energy, Inc. ("Diamondback") that have been included on pages F-1 to F-54 in Diamondback's Annual Report on Form 10-K (File No. 001-35700) filed with the SEC on February 19, 2015, as such Annual Report on Form 10-K may be amended from time to time, which Financial Statements are incorporated herein by reference.
(2) Financial Statement Schedules
All financial statement schedules have been omitted because they are not applicable or the required disclosure is presented in the financial statements or notes thereto.
(3) Exhibits

Exhibit Number	Description
2.1##	Purchase and Sale Agreement, dated as of December 13, 2016, by and among Gulfport Energy Corporation, SCOOP Acquisition Company, LLC and Vitruvian II Woodford, LLC (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 15, 2016).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
3.5	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 2, 2014).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company's 6.625% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 21, 2015).
4.3	

Indenture, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.000% Senior Notes due 2024) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 19, 2016).

4.4 Registration Rights Agreement, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC and Scotia Capital (USA) Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 19, 2016).

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4.5	Indenture, dated as of December 21, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.375% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 21, 2016).
4.6	Registration Rights Agreement, dated as of December 21, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 21, 2016).
4.7	Voting Rights Waiver Agreement, dated June 10, 2015, by and among Gulfport Energy Corporation, Putnam Investment Management, LLC, The Putnam Advisory Company, LLC and Putnam Fiduciary Trust Company (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 12, 2015)
10.1+	2013 Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form S-4, File No. 333-189992, filed by the Company with the SEC on July 17, 2013).
10.2+	2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 7, 2014).
10.3+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.4+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to the Form 10-K, File No. 000-19514, filed by the Company with the SEC on February 28, 2014).
10.5+	Consulting Agreement, effective as of June 14, 2013, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 19, 2013).
10.6+	Separation and Release Agreement, dated as of January 31, 2014, by and between the Company and James D. Palm (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 4, 2014).
10.7+	Amended and Restated Employment Agreement, dated as of April 29, 2015, by and between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 7, 2015).
10.8	Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 3, 2014).
10.9	First Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole

	bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 28, 2014).
10.10	Second Amendment to Amended and Restated Credit Agreement, dated as of November 26, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 3, 2014).
10.11	Third Amendment to Amended and Restated Credit Agreement, dated as of April 10, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 15, 2015).
10.12	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 29, 2015, among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on August 7, 2015).

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10.13	Fifth Amendment to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on September 24, 2015).
10.14	Sixth Amendment, dated February 19, 2016, to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 5, 2016).
10.15	Seventh Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2016, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 15, 2016).
10.16#	Sand Supply Agreement, effective as of October 1, 2014, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).
10.17#	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 5, 2015).
10.18#	Amended and Restated Master Services Agreement, effective as of October 1, 2014, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).
10.19#	Amendment to Amended and Restated Master Services Agreement, dated as of February 18, 2016 to be effective as of January 1, 2016, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC.
10.20+	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-4, File No. 333-199905, filed by the Company with the SEC on November 6, 2014).
10.21+	Separation and Release Agreement by and between Gulfport Energy Corporation and Ross Kirtley entered into November 2, 2016 (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 3, 2016).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company.
23.3*	Consent of Netherland, Sewell & Associates, Inc.

23.4*	Consent of Grant Thornton LLP with respect to financial statements of Diamondback Energy, Inc.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document.

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101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.
** Furnished herewith, not filed.
+ Management contract, compensatory plan or arrangement.
# Confidential treatment with respect to certain portions of this agreement was granted by the SEC which portions have been omitted and filed separately with the SEC.

The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 14, 2017

GULFPORT ENERGY CORPORATION

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

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:	February 14, 2017	By:	/s/ MICHAEL G. MOORE Michael G. Moore Chief Executive Officer and President, Director (Principal Executive Officer)
Date:	February 14, 2017	By:	/s/ DAVID L. HOUSTON David L. Houston Chairman of the Board and Director
Date:	February 14, 2017	By:	/s/ KERI CROWELL Keri Crowell Chief Financial Officer (Principal Accounting and Financial Officer)
Date:	February 14, 2017	By:	/s/ CRAIG GROESCHEL Craig Groeschel Director
Date:	February 14, 2017	By:	/s/ C. DOUG JOHNSON C. Doug Johnson Director
Date:	February 14, 2017	By:	/s/ BEN T. MORRIS Ben T. Morris Director
Date:	February 14, 2017	By:	/s/ SCOTT E. STRELLER Scott E. Streller Director

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
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Report of Independent Registered Public Accounting Firm
Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive (loss) income, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gulfport Energy Corporation and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company adopted new accounting guidance in 2016 related to the presentation of deferred income taxes.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 14, 2017 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP
Oklahoma City, Oklahoma
February 14, 2017

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GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$1,275,875	$112,974
Restricted cash	185,000	—
Accounts receivable—oil and gas	136,761	71,872
Accounts receivable—related parties	16	16
Prepaid expenses and other current assets	7,639	3,905
Derivative instruments	3,488	142,794
Total current assets	1,608,779	331,561
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $1,580,305 and $1,817,701 excluded from amortization in 2016 and 2015, respectively	6,071,920	5,424,342
Other property and equipment	68,986	33,171
Accumulated depletion, depreciation, amortization and impairment	(3,789,780)	(2,829,110)
Property and equipment, net	2,351,126	2,628,403
Other assets:		
Equity investments	243,920	242,393
Derivative instruments	5,696	51,088
Deferred tax asset	4,692	74,925
Other assets	8,932	6,364
Total other assets	263,240	374,770
Total assets	$4,223,145	$3,334,734
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$265,124	$265,128
Asset retirement obligation	195	75
Derivative instruments	119,219	437
Deferred tax liability	—	50,697
Current maturities of long-term debt	276	179
Total current liabilities	384,814	316,516
Long-term derivative instrument	26,759	6,935
Asset retirement obligation	34,081	26,362
Long-term debt, net of current maturities	1,593,599	946,084
Total liabilities	2,039,253	1,295,897
Commitments and contingencies (Notes 15 and 16)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—	—
Stockholders' equity:		
Common stock, $.01 par value; 200,000,000 authorized, 158,829,816 issued and outstanding in 2016 and 108,322,250 in 2015	1,588	1,082
Paid-in capital	3,946,442	2,824,303
Accumulated other comprehensive loss	(53,058)	(55,177)

Retained deficit	(1,711,080)	(731,371)
Total stockholders' equity	2,183,892	2,038,837
Total liabilities and stockholders' equity	$4,223,145	$3,334,734

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2016	2015	2014
	(In thousands, except share data)		
Revenues:			
Gas sales	$420,128	$324,733	$226,126
Oil and condensate sales	81,173	122,615	241,210
Natural gas liquid sales	59,115	58,129	94,127
Net (loss) gain on gas, oil, and NGL derivatives	(174,506)	203,513	109,299
	385,910	708,990	670,762
Costs and expenses:			
Lease operating expenses	68,877	69,475	52,191
Production taxes	13,276	14,740	24,006
Midstream gathering and processing	165,972	138,590	64,467
Depreciation, depletion and amortization	245,974	337,694	265,431
Impairment of oil and gas properties	715,495	1,440,418	—
General and administrative	43,409	41,967	38,290
Accretion expense	1,057	820	761
Gain on sale of assets	—	—	(11)
	1,254,060	2,043,704	445,135
(LOSS) INCOME FROM OPERATIONS	(868,150)	(1,334,714)	225,627
OTHER (INCOME) EXPENSE:			
Interest expense	63,530	51,221	23,986
Interest income	(1,230)	(643)	(195)
Litigation settlement	—	—	25,500
Insurance proceeds	(5,718)	(10,015)	—
Loss on debt extinguishment	23,776	—	—
Gain on contribution of investments	—	—	(84,470)
Loss (income) from equity method investments	33,985	106,093	(139,434)
Other expense (income)	129	(485)	(504)
	114,472	146,171	(175,117)
(LOSS) INCOME BEFORE INCOME TAXES	(982,622)	(1,480,885)	400,744
INCOME TAX (BENEFIT) EXPENSE	(2,913)	(256,001)	153,341
NET (LOSS) INCOME	$(979,709)	$(1,224,884)	$247,403
NET (LOSS) INCOME PER COMMON SHARE:			
Basic	$(7.97)	$(12.27)	$2.90
Diluted	$(7.97)	$(12.27)	$2.88
Weighted average common shares outstanding—Basic	122,952,866	99,792,401	85,445,963
Weighted average common shares outstanding—Diluted	122,952,866	99,792,401	85,813,182

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	For the Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Net (loss) income	$(979,709)	$(1,224,884)	$247,403
Foreign currency translation adjustment (1)	2,119	(28,502)	(16,894)
Other comprehensive income (loss)	2,119	(28,502)	(16,894)
Comprehensive (loss) income	$(977,590)	$(1,253,386)	$230,509

(1) Net of $1.3 million in taxes for the year ended December 31, 2016. No taxes were recorded for the years ended December 31, 2015 and 2014.

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Paid-in	Accumulated Other Comprehensive Loss	Retained Earnings (Deficit)	Total Stockholders' Equity
	Shares	Amount	Capital			
	(In thousands, except share data)					
Balance at January 1, 2014	85,177,532	$ 851	$ 1,813,058	$ (9,781)	$ 246,110	$ 2,050,238
Net income	—	—	—	—	247,403	247,403
Other Comprehensive Loss	—	—	—	(16,894)	—	(16,894)
Stock Compensation	—	—	14,860	—	—	14,860
Issuance of Restricted Stock	272,665	3	(3)	—	—	—
Issuance of Common Stock through exercise of options	205,241	2	687	—	—	689
Balance at December 31, 2014	85,655,438	856	1,828,602	(26,675)	493,513	2,296,296
Net loss	—	—	—	—	(1,224,884)	(1,224,884)
Other Comprehensive Loss	—	—	—	(28,502)	—	(28,502)
Stock Compensation	—	—	14,359	—	—	14,359
Issuance of Common Stock in public offerings, net of related expenses	22,425,000	224	981,299	—	—	981,523
Issuance of Restricted Stock	236,812	2	(2)	—	—	—
Issuance of Common Stock through exercise of options	5,000	—	45	—	—	45
Balance at December 31, 2015	108,322,250	1,082	2,824,303	(55,177)	(731,371)	2,038,837
Net loss	—	—	—	—	(979,709)	(979,709)
Other Comprehensive Income	—	—	—	2,119	—	2,119
Stock Compensation	—	—	12,251	—	—	12,251
Issuance of Common Stock in public offerings, net of related expenses	50,255,000	503	1,109,891	—	—	1,110,394
Issuance of Restricted Stock	252,566	3	(3)	—	—	—
Balance at December 31, 2016	158,829,816	$ 1,588	$ 3,946,442	$ (53,058)	$ (1,711,080)	$ 2,183,892

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Cash flows from operating activities:			
Net (loss) income	$(979,709)	$(1,224,884)	$247,403
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Accretion of discount—Asset Retirement Obligation	1,057	820	761
Depletion, depreciation and amortization	245,974	337,694	265,431
Impairment of oil and gas properties	715,495	1,440,418	—
Stock-based compensation expense	7,351	8,616	8,916
Loss (gain) from equity investments	34,397	113,120	(54,171)
Gain on debt extinguishment	(1,108)	—	—
Gain on contribution of investments	—	—	(84,470)
Interest income - note receivable	—	—	(46)
Loss (gain) on derivative instruments	323,303	(83,671)	(121,148)
Deferred income tax expense (benefit)	18,188	(254,493)	122,917
Amortization of loan commitment fees	3,660	3,219	1,685
Amortization of note discount and premium	(1,716)	(2,165)	(533)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(64,889)	31,986	(45,034)
Decrease in accounts receivable—related party	—	30	2,571
Increase in prepaid expenses	(3,734)	(191)	(1,133)
Increase (decrease) in accounts payable and accrued liabilities and other	43,763	(47,199)	73,925
Settlement of asset retirement obligation	(4,189)	(1,121)	(7,201)
Net cash provided by operating activities	337,843	322,179	409,873
Cash flows from investing activities:			
Deductions to cash held in escrow	8	8	8
Additions to other property and equipment	(33,152)	(13,572)	(7,030)
Additions to oil and gas properties	(724,925)	(1,579,129)	(1,329,277)
Proceeds from sale of oil and gas properties	45,812	27,998	4,404
Repayments on note receivable to related party	—	—	875
Proceeds from sale of investments	—	—	258,362
Contributions to equity method investments	(26,472)	(14,472)	(63,999)
Distributions from equity method investments	18,147	4,914	—
Funding of restricted cash	(185,000)	—	—
Net cash used in investing activities	(905,582)	(1,574,253)	(1,136,657)
Cash flows from financing activities:			
Principal payments on borrowings	(87,685)	(350,172)	(115,690)
Borrowings on line of credit	86,000	250,000	215,000
Proceeds from bond issuance	1,250,000	350,000	318,000
Repayment of bonds	(624,561)	—	—
Borrowings on term loan	21,049	—	—
Debt issuance costs and loan commitment fees	(24,718)	(8,688)	(7,831)
Proceeds from issuance of common stock, net of offering costs and exercise of stock options	1,110,555	981,568	689

Net cash provided by financing activities	1,730,640	1,222,708	410,168
Net increase (decrease) in cash and cash equivalents	1,162,901	(29,366)	(316,616)
Cash and cash equivalents at beginning of period	112,974	142,340	458,956
Cash and cash equivalents at end of period	$1,275,875	$112,974	$142,340
Supplemental disclosure of cash flow information:			
Interest payments	$68,966	$59,736	$28,646
Income tax (receipts) payments	$(19,770)	$16,156	$23,800
Supplemental disclosure of non-cash transactions:			
Capitalized stock based compensation	$4,900	$5,743	$5,944
Asset retirement obligation capitalized	$10,971	$8,800	$9,295
Interest capitalized	$9,148	$13,580	$9,687
Foreign currency translation gain (loss) on equity method investments	$3,468	$(28,502)	$(16,894)

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2016, 2015 AND 2014

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation ("Gulfport" or the "Company") is an independent oil and gas exploration, development and production company with its principal properties located in the Utica Shale primarily in Eastern Ohio and along the Louisiana Gulf Coast. The Company also has an interest in producing properties in Northwestern Colorado in the Niobrara Formation and in Western North Dakota in the Bakken Formation, and has investments in companies operating in the United States, Canada and Thailand.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the statement of cash flows.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly owned subsidiaries, Grizzly Holdings Inc., Jaguar Resources LLC, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Westhawk Minerals LLC, Puma Resources, Inc., Gulfport Buckeye LLC, Gulfport Midstream Holdings, LLC, and SCOOP Acquisition Company, LLC. All intercompany balances and transactions are eliminated in consolidation.

Accounts Receivable

The Company's accounts receivable—oil and gas primarily are from companies in the oil and gas industry. The majority of its receivables are from three purchasers of the Company's oil and gas and receivables from joint interest owners on properties the Company operates. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2016 and December 31, 2015.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for 2016, 2015 and 2014, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can result in a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. As a result of the decline in commodity prices, the Company recognized a ceiling test impairment of $715.5 million for the year ended

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December 31, 2016. If prices of oil, natural gas and natural gas liquids continue to decline, the Company may be required to further write down the value of its oil and natural gas properties, which could negatively affect its results of operations.

Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting barrels to gas at the ratio of one barrel of oil to six Mcf of gas. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled approximately $1.6 billion and $1.8 billion at December 31, 2016 and December 31, 2015, respectively. These costs are reviewed quarterly by management for impairment. If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities under Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 410, “Asset Retirement and Environmental Obligations” (“FASB ASC 410”), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over the estimated useful lives of the related assets, which range from 3 to 30 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport’s consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. The assets and liabilities of the Canadian investment are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented and equity contributions are translated at the current exchange rate in effect at the date of the contribution. In addition, the Company has an equity investment in a U.S. company that has a subsidiary that is a Canadian entity whose functional currency is the Canadian dollar. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders’ equity. The following table presents the balances of the Company’s cumulative translation adjustments included in accumulated other comprehensive loss, exclusive of taxes.

	(In thousands)
December 31, 2013	$ (9,781)
December 31, 2014	$ (26,675)
December 31, 2015	$ (55,175)
December 31, 2016	$ (51,709)

Net Income per Common Share

Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net income per common share are illustrated in Note 11.

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Income Taxes

Gulfport uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company’s 1998 – 2015 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2016, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. For the year ended December 31, 2016, there is no interest or penalties associated with uncertain tax positions in the Company’s consolidated financial statements.

Revenue Recognition

Natural gas revenues are recorded in the month produced and delivered to the purchaser using the entitlement method, whereby any production volumes received in excess of the Company’s ownership percentage in the property are recorded as a liability. If less than Gulfport’s entitlement is received, the underproduction is recorded as a receivable. At December 31, 2016 and 2015, the Company had no gas imbalance liability. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments—Equity Method

Investments in entities in which the Company owns an equity interest greater than 20% and less than 50% and/or investments in which it has significant influence are accounted for under the equity method. Under the equity method, the Company’s share of investees’ earnings or loss is recognized in the statement of operations. In accordance FASB ASC 825, "Financial Instruments," the Company elected the fair value option of accounting for its equity method investment in the common stock of Diamondback Energy Inc. ("Diamondback"). At the end of each reporting period, the quoted closing market price of Diamondback's common stock was multiplied by the total shares owned by the Company and the resulting gain or loss was recognized in loss (income) from equity method investments in the consolidated statements of operations. As of December 31, 2016 and 2015, the Company did not own any shares of Diamondback's common stock.

The Company reviews its investments annually to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. The Company recognized impairment charges of $23.1 million and $101.6 million related to its investment in Grizzly Oil Sands ULC for the years ended December 31, 2016 and December 31, 2015, respectively. At December 31, 2014, the Company recognized an impairment of $12.1 million related to its investment in Tatex Thailand III, LLC. See Note 4 for further discussion of these impairments.

Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of FASB ASC 718, “Compensation—Stock Compensation” (“FASB ASC 718”). FASB ASC 718 requires share-based payments to employees, including grants of restricted stock, to be recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period. The vesting periods for restricted shares range between two to five years with either quarterly or annual vesting installments.

Derivative Instruments

The Company utilizes commodity derivatives to manage the price risk associated with forecasted sale of its natural gas, crude oil and natural gas liquid production. The Company follows the provisions of FASB ASC 815, “Derivatives and Hedging” (“FASB ASC 815”) as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value.

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The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. While the Company has historically designated derivative instruments as accounting hedges, effective January 1, 2015, the Company discontinued hedge accounting prospectively. The Company's current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company’s oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Reclassification

Certain reclassifications have been made to prior period financial statements and related disclosures to conform to current period presentation.

Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The core principle of the new standard is for the recognition of revenue to depict the transfer of goods or services to customers in amounts that reflect the payment to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those years, using either a full or a modified retrospective application approach. In July 2015, the FASB decided to defer the effective date by one year (until 2018). The Company is evaluating the impact of this ASU on its consolidated financial statements, and based on the continuing evaluation of its revenue streams, this ASU is not expected to have a material impact on its net income. The Company is still in the process of determining whether or not it will use the retrospective method or the modified retrospective approach to implementation.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40). The new guidance addresses management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and in certain circumstances to provide related footnote disclosures. The standard is effective for periods after December 15, 2016, with early adoption permitted. The Company adopted this guidance in the fourth quarter of 2016 with no impact to its consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities, such as limited partnerships, limited liability corporation and securitization structure, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models. The ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. The Company adopted this ASU on January 1, 2016. As a result, certain of the Company's equity investments were determined to be variable interest entities; however, the Company was not required to consolidate these investments.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. To simplify the presentation of debt issuance costs, ASU 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. This guidance is effective for periods after December 15, 2015. The Company adopted this guidance on a retrospective basis in the fourth quarter of 2015 and has debt issuance costs offsetting long-term debt at December 31, 2016 and December 31, 2015 as shown in Note 6.

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In September 2015, the FASB issued ASU No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments. The guidance eliminates the requirement to retrospectively adjust the financial statements for measurement-period adjustments that occur in periods after a business combination is consummated. Measurement period adjustments are calculated as if they were known at the acquisition date, but are recognized in the reporting period in which they are determined. Additional disclosures are required about the impact on current-period income statement line items of adjustments that would have been recognized in prior periods if the prior-period information had been revised. The guidance is effective for periods after December 15, 2015. The Company adopted this guidance in the first quarter of 2016 and there was no impact to its consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes (Topic 705). Current guidance requires an entity to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified statement of financial position. Deferred tax liabilities and assets are classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. Deferred tax liabilities and assets that are not related to an asset or liability for financial reporting are classified according to the expected reversal date of the temporary difference. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred income tax liabilities and assets be classified as noncurrent in a classified statement of financial position. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company adopted this guidance in the fourth quarter of 2016 on a prospective basis; therefore, prior periods were not retrospectively adjusted.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The guidance requires the lessee to recognize most leases on the balance sheet thereby resulting in the recognition of lease assets and liability for those leases currently classified as operating leases. The accounting for lessors is largely unchanged. The guidance is effective for periods after December 15, 2018, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements and related disclosures; however, based on the Company's current operating leases, it is not expected to have a material impact.

In March 2016, the FASB issued ASU No. 2016-05, Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships. The guidance was issued to clarify that change in the counterparty to a derivative instrument that had been designated as the hedging instrument under Topic 815, does not require designation of that hedging relationship provided that all other hedge accounting criteria continue to be met. This guidance is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact on its consolidated financial statements. The Company does not believe that the adoption of this guidance will have a material impact on its consolidated financial statements as all current derivative instruments are not designated for hedge accounting.

In March 2016, the FASB issued ASU No. 2016-07, Equity Method and Joint Ventures. This guidance simplified current requirements by eliminating the need to retrospectively apply the equity method of accounting upon obtaining significant influence over an investment that it previously accounted for under the cost basis or at fair value. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company adopted this guidance in the fourth quarter of 2016 and there was no impact to its consolidated financial statements as all current investments are accounted for under the equity method of accounting.

In March 2016, the FASB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance was intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This guidance is effective for periods after December 15, 2016, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In May 2016, the FASB issued ASU No. 2016-11, Revenue Recognition and Derivatives and Hedging: Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. This guidance rescinds SEC Staff Observer comments that are codified in Topic 606, Revenue Recognition, and Topic 932, Extractive Activities--Oil and Gas. This amendment is effective upon adoption of Topic 606. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and instead, requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposure,

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reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. The Company is currently evaluating the impact this standard will have on its financial statements and related disclosures and does not anticipate it to have a material affect.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. This guidance provides guidance of eight specific cash flow issues. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements.

In October 2016, the FASB issued ASU No. 2016-17, Consolidation: Interests Held through Related Parties That Are under Common Control. This guidance provides an amendment to the consolidation guidance on how a reporting entity that is the single decision maker of a VIE should treat indirect interests in the entity held through related parties that are under common control with the reporting entity when determining whether it is the primary beneficiary of that VIE. The Company has adopted this ASU and there was no current impact on its consolidated financial statements.

In December 2016, the FASB issued ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers. This guidance updates narrow aspects of the guidance issued in Update 2014-09. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this ASU on its consolidated financial statements.

2. ACQUISITIONS

In April 2015, the Company entered into an agreement to acquire Paloma Partners III, LLC, which is now know as Gulfport Buckeye LLC ("Buckeye"), for a total purchase price of approximately $301.9 million, subject to certain adjustments. Buckeye holds approximately 24,000 net nonproducing acres in the Utica Shale of Ohio. In accordance with the agreement, the Company deposited $75.0 million into an escrow account. At the closing of the transaction the deposit was credited toward the purchase price. This transaction closed on August 31, 2015 for a purchase price of approximately $302.3 million, net of purchase price adjustments. At closing, approximately $30.1 million of the purchase price was placed in escrow as security to the Company for potential indemnification claims that may occur as a result of the sale.

On June 9, 2015, the Company completed the acquisition of 6,198 gross and net acres located in Belmont and Jefferson Counties, Ohio from American Energy-Utica, LLC ("AEU") for a purchase price of approximately $68.2 million, subject to adjustment. On June 12, 2015, the Company completed the acquisition of 38,965 gross (27,228 net) acres located in Monroe County, Ohio, 14.6 MMcf per day of average net production (estimated for April 2015), 18 gross (11.3 net) drilled but uncompleted wells, an 11 mile gas gathering system and a four well pad location from AEU for a total purchase price of approximately $319.0 million (the "Monroe Acquisition"). On June 29, 2015, the Company acquired an additional 4,950 gross (1,900 net) acres in Monroe County for an additional $18.2 million from AEU. The total purchase price of these transactions (collectively referred to as the "AEU Acquisition"), was approximately $405.4 million ($405.0 million net of purchase price adjustments). At closing, approximately $67.1 million of the purchase price was placed in escrow pending completion of title review after the closing. In December 2015, approximately $2.4 million of the escrow was released and returned to the Company as a result of final title review.

The AEU 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 June 12, 2015 acquisition date. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See Note 13 for additional discussion of the measurement inputs.

The Company estimated that the consideration paid in the AEU Acquisition for these properties approximated the fair value that would be paid by a typical market participant. As a result, no goodwill or bargain purchase gain was recognized in conjunction with the purchase.

The following table summarizes the consideration paid in the AEU Acquisition to acquire the properties and the fair value amount of the assets acquired as of June 12, 2015. Both the consideration paid and the fair value assigned to the assets is preliminary and subject to adjustment upon final closing.

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	(In thousands)
Consideration paid	
Cash, net of purchase price adjustments	$ 405,029
Fair value of identifiable assets acquired	
Oil and natural gas properties	
Proved	$ 70,804
Unevaluated	334,225
Fair value of net identifiable assets acquired	$ 405,029

3. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2016 and 2015 are as follows:

	December 31,	
	2016	2015
	(In thousands)	
Oil and natural gas properties	$6,071,920	$5,424,342
Office furniture and fixtures	21,204	12,589
Building	42,530	16,915
Land	5,252	3,667
Total property and equipment	6,140,906	5,457,513
Accumulated depletion, depreciation, amortization and impairment	(3,789,780)	(2,829,110)
Property and equipment, net	$2,351,126	$2,628,403

At December 31, 2016 and 2015, the net book value of the Company's oil and natural gas properties was above the calculated ceiling as a result of the reduced commodity prices during the years ended December 31, 2016 and 2015, respectively. As a result, the Company recorded an impairment of its oil and natural gas properties under the full cost method of accounting in the amount of $715.5 million and $1.4 billion for the years ended December 31, 2016 and 2015, respectively. No impairment of oil and natural gas properties was required under the ceiling test for the year ended December 31, 2014.

Included in oil and natural gas properties at December 31, 2016 and 2015 is the cumulative capitalization of $129.9 million and $100.6 million, respectively, in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management’s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $29.3 million, $27.9 million and $25.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

The following is a summary of Gulfport’s oil and gas properties not subject to amortization as of December 31, 2016:

	Costs Incurred in				
	2016	2015	2014	Prior to 2014	Total
	(In thousands)				
Acquisition costs	$147,382	$515,905	$314,077	$571,924	$1,549,288
Exploration costs	—	—	—	—	—
Development costs	18,853	5,067	3,248	1,533	28,701
Capitalized interest	3,632	(876)	(2,504)	2,064	2,316
Total oil and gas properties not subject to amortization	$169,867	$520,096	$314,821	$575,521	$1,580,305

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The following table summarizes the Company’s non-producing properties excluded from amortization by area as of December 31, 2016:

	December 31, 2016 (In thousands)
Utica	$ 1,577,207
Niobrara	2,172
Southern Louisiana	462
Bakken	96
Other	368
	$ 1,580,305

As of December 31, 2015, approximately $1.8 billion of non-producing leasehold costs was not subject to amortization.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company’s activities, the inclusion of most of the above referenced costs into the Company’s amortization calculation typically occurs within three to five years. However, the majority of the Company's non-producing leases have five year extension terms which could extend this time frame beyond five years.

A reconciliation of the Company's asset retirement obligation for the years ended December 31, 2016 and 2015 is as follows:

	December 31,	
	2016	2015
	(In thousands)	
Asset retirement obligation, beginning of period	$26,437	$17,938
Liabilities incurred	10,971	8,800
Liabilities settled	(4,189)	(1,121)
Accretion expense	1,057	820
Asset retirement obligation as of end of period	34,276	26,437
Less current portion	195	75
Asset retirement obligation, long-term	$34,081	$26,362

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4. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2016 and 2015:

	Approximate Ownership %	Carrying Value December 31, 2016	Carrying Value December 31, 2015	Loss (income) from equity method investments For the Year Ended December 31, 2016	2015	2014
		(In thousands)				
Investment in Tatex Thailand II, LLC	23.5 %	$—	$—	$(412)	$189	$(475)
Investment in Tatex Thailand III, LLC	17.9 %	—	—	—	—	12,408
Investment in Grizzly Oil Sands ULC	24.9999 %	45,213	50,645	25,150	115,544	13,159
Investment in Bison Drilling and Field Services LLC	— %	—	—	—	—	213
Investment in Muskie Proppant LLC	— %	—	—	—	—	371
Investment in Timber Wolf Terminals LLC	50.0 %	991	999	8	14	9
Investment in Windsor Midstream LLC	22.5 %	25,749	27,955	(13,618)	(18,398)	(477)
Investment in Stingray Pressure Pumping LLC	— %	—	—	—	—	2,027
Investment in Stingray Cementing LLC	50.0 %	1,920	2,487	263	147	344
Investment in Blackhawk Midstream LLC	48.5 %	—	—	—	(7,216)	(84,787)
Investment in Stingray Logistics LLC	— %	—	—	—	—	(464)
Investment in Diamondback Energy, Inc.	— %	—	—	—	—	(79,654)
Investment in Stingray Energy Services LLC	50.0 %	4,215	5,908	1,044	557	(88)
Investment in Sturgeon Acquisitions LLC	25.0 %	20,526	22,769	993	(1,229)	(1,819)
Investment in Mammoth Energy Services, Inc.	24.2 %	111,717	131,630	20,646	16,485	(201)
Investment in Strike Force Midstream LLC	25.0 %	33,589	—	(89)	—	—
		$243,920	$242,393	$33,985	$106,093	$(139,434)

The tables below summarize financial information for the Company's equity investments, as of December 31, 2016 and 2015.

Summarized balance sheet information:

	December 31, 2016	2015
	(In thousands)	
Current assets	$148,733	$105,537
Noncurrent assets	$1,305,407	$1,293,925
Current liabilities	$57,173	$56,559
Noncurrent liabilities	$67,680	$155,995

Summarized results of operations:

	December 31, 2016	2015	2014
	(In thousands)		
Gross revenue	$287,733	$430,729	$390,620
Net loss (income)	$65,070	$(16,761)	$140,796

Gross revenue and net loss presented above for 2014 include approximately one month of activity for Mammoth Energy Partners LP ("Mammoth") and approximately eleven months of activity for Stingray Pressure Pumping LLC ("Stingray

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Pressure"), Stingray Logistics LLC ("Stingray Logistics"), Muskie Proppant LLC ("Muskie") and Bison Drilling and Field Services LLC ("Bison"), which were contributed to Mammoth in November 2014. In October 2016, Mammoth converted into a limited liability company and the Company contributed its interest in that entity to Mammoth Energy Services, Inc. ("Mammoth Energy") in connection with Mammoth Energy's initial public offering. See further discussion of these contributions below.

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC (“Tatex”). Tatex holds an 8.5% interest in APICO, LLC (“APICO”), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 180,000 acres which includes the Phu Horm Field.

Tatex Thailand III, LLC

The Company has an ownership interest in Tatex Thailand III, LLC ("Tatex III"). Tatex III previously owned a concession covering approximately 245,000 acres in Southeast Asia. The Company paid cash calls of $1.6 million during the year ended December 31, 2014. As of December 31, 2014, the Company reviewed its investment in Tatex III and, together with Tatex III, made the decision to allow the concession to expire in January 2015. As such, the Company fully impaired the asset as of December 31, 2014, recognizing a loss of $12.1 million which is included in loss (income) from equity method investments in the accompanying consolidated statements of operations.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns an interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. ("Oil Sands"). As of December 31, 2016, Grizzly had approximately 830,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. Initiation of steam injection at its first project, Algar Lake Phase 1, commenced in January 2014 and first bitumen production was achieved during the second quarter of 2014. In April 2015, Grizzly determined to cease bitumen production at its Algar Lake facility due to the level of commodity prices. Grizzly continues to monitor market conditions as it assesses future plans for the facility. The Company reviewed its investment in Grizzly as of September 30, 2015 and December 31, 2015, and again at March 31, 2016 for impairment based on FASB ASC 323 due to certain qualitative factors and as such, engaged an independent third party to assist management in determining fair value calculations of its investment. As a result of the calculated fair values and other qualitative factors, the Company concluded that an other than temporary impairment was required under FASB ASC 323, resulting in an aggregate impairment loss of $101.6 million for the year ended December 31, 2015 and $23.1 million for the year ended December 31, 2016, which is included in loss (income) from equity method investments in the consolidated statements of operations. As of and during the period ended December 31, 2016, commodity prices had increased as compared to the quarter ended March 31, 2016, and there were no impairment indicators that required further evaluation for impairment. If commodity prices decline in the future however, further impairment of the investment in Grizzly may be necessary. During the years ended December 31, 2016 and 2015, Gulfport paid $15.5 million and $14.5 million, respectively, in cash calls. Grizzly’s functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by $4.2 million as a result of a foreign currency translation gain and decreased by $28.5 million and $16.9 million as a result of a foreign currency translation loss for the years ended December 31, 2016, 2015, and 2014, respectively.

Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which Grizzly paid the outstanding balance in full in July 2016. Gulfport paid its share of this amount on June 30, 2016.

Bison Drilling and Field Services LLC

During 2011, the Company invested in Bison. Bison owns and operates drilling rigs. During the year ended December 31, 2014, the Company paid $17.0 million in cash calls.

The Company contributed its investment in Bison to Mammoth during the fourth quarter of 2014. See below under "Mammoth Energy Partners LP/Mammoth Energy Services, Inc." for information regarding this contribution.

Muskie Proppant LLC

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During 2011, the Company invested in Muskie. Muskie processes and sells sand for use in hydraulic fracturing by the oil and natural gas industry and holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. During the year ended December 31, 2014, the Company paid $1.0 million in cash calls to Muskie. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

The Company entered into a loan agreement with Muskie effective July 1, 2013, under which it loaned Muskie $0.9 million. Interest accrued at the prime rate plus 2.5%. The loan had an original maturity date of July 31, 2014. Effective July 31, 2014, an amendment was made to the loan agreement which changed the maturity date of the loan to July 31, 2015. During the fourth quarter of 2014, Muskie repaid the outstanding balance and the loan agreement was terminated.

The Company contributed its investment in Muskie to Mammoth during the fourth quarter of 2014. See below under "Mammoth Energy Partners LP/Mammoth Energy Services, Inc." for information regarding this contribution.

Timber Wolf Terminals LLC

During 2012, the Company invested in Timber Wolf Terminals LLC (“Timber Wolf”). Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. During the years ended December 31, 2016 and 2015, the Company paid no cash calls to Timber Wolf.

Windsor Midstream LLC

During 2012, the Company purchased an ownership interest in Windsor Midstream LLC (“Midstream”). Midstream owned a 28.4% interest in Coronado Midstream LLC ("Coronado"), a gas processing plant in West Texas. In March 2015, Coronado was sold to Enlink Midstream Partners, LP ("Enlink") for proceeds of approximately $600.0 million, consisting of cash and units representing a limited partnership interest in Enlink. Midstream recorded an $81.6 million gain on the sale of its investment in Coronado. During the years ended December 31, 2016 and 2015, the Company received $15.8 million and $3.9 million, respectively, in distributions from Midstream.

Stingray Pressure Pumping LLC

During 2012, the Company invested in Stingray Pressure. Stingray Pressure provides well completion services. During the year ended December 31, 2014, the Company paid $2.5 million in cash calls. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

The Company contributed its investment in Stingray Pressure to Mammoth during the fourth quarter of 2014. See below under "Mammoth Energy Partners LP/Mammoth Energy Services, Inc." for information regarding this contribution.

Stingray Cementing LLC

During 2012, the Company invested in Stingray Cementing LLC ("Stingray Cementing"). Stingray Cementing provides well cementing services. During the years ended December 31, 2016 and 2015, the Company did not pay any cash calls related to Stingray Cementing. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC ("Blackhawk"). Blackhawk coordinates gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. On January 28, 2014, Blackhawk closed on the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of $190.0 million, of which $14.3 million was placed in escrow. Gulfport received $84.8 million in net proceeds from this transaction in the first quarter of 2014, which is included as income from equity method investments in the accompanying consolidated statements of operations. During the year ended December 31, 2015, the Company received net proceeds of approximately $7.2 million from the release of escrow from the Blackhawk sale, which is included in loss (income) from equity investments in the consolidated statements of operations.

Stingray Logistics LLC

During 2012, the Company invested in Stingray Logistics. Stingray Logistics provides well services.

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The Company contributed its investment in Stingray Logistics to Mammoth during the fourth quarter of 2014. See below under "Mammoth Energy Partners LP/Mammoth Energy Services, Inc." for information regarding this contribution.

Diamondback Energy, Inc.

On May 7, 2012, the Company entered into a contribution agreement with Diamondback. Under the terms of the contribution agreement, the Company agreed to contribute to Diamondback, prior to the closing of the Diamondback initial public offering ("Diamondback IPO"), all its oil and natural gas interests in the Permian Basis (the "Contribution"). The Contribution was completed on October 11, 2012. Following the closing of the Diamondback IPO, the Company owned 7,914,036 shares of Diamondback's outstanding common stock for an initial investment in Diamondback valued at $138.5 million. In 2013, the Company sold an aggregate of 4,534,536 shares of its Diamondback common stock and received aggregate net proceeds of approximately $192.7 million. In June and September of 2014, the Company sold an aggregate of 2,437,500 shares of its Diamondback common stock and received aggregate net proceeds of approximately $197.6 million. On November 12, 2014, the Company sold its remaining 942,000 shares of Diamondback common stock for net proceeds of approximately $60.8 million, and therefore, did not own any shares of Diamondback common stock as of December 31, 2016 or 2015.

The Company accounted for its interest in Diamondback as an equity method investment and had elected the fair value option of accounting for this investment. While the Company's ownership interest in Diamondback was below 20% prior to the Company's sale of its remaining Diamondback common stock in November 2014, the Company had appointed a member of Diamondback's Board. The individual appointed by the Company continues to serve on Diamondback's board and the Company had influence through this board seat. The Company recognized a gain of approximately $79.7 million on its investment in Diamondback for year ended December 31, 2014, which is included as loss (income) from equity method investments in the consolidated statements of operations.

The Company has determined that for the 2014 period presented in its consolidated financial statements, Diamondback met the conditions of a significant subsidiary under Rule 1-02(w) of Regulation S-X, for which the Company is required, pursuant to Rule 3-09 of Regulation S-X, to attach separate financial statements as exhibits to its Annual Report on Form 10-K. During 2015 and 2016, the Company did not own any shares of Diamondback common stock and, as such, Rule 3-09 of Regulation S-X is not applicable and the 2015 and 2016 consolidated financial statements of Diamondback are not attached.

Stingray Energy Services LLC

During 2013, the Company invested in Stingray Energy Services LLC ("Stingray Energy"). Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. During the years ended December 31, 2016 and 2015, the Company did not pay any cash calls to Stingray Energy. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

Sturgeon Acquisitions LLC

During the third quarter of 2014, the Company invested $20.7 million and received an ownership interest of 25% in Sturgeon Acquisitions LLC ("Sturgeon"). Sturgeon owns and operates sand mines that produce hydraulic fracturing grade sand. During the years ended December 31, 2016 and 2015, the Company received approximately $1.3 million and $1.0 million, respectively, in distributions from Sturgeon.

Mammoth Energy Partners LP/Mammoth Energy Services, Inc.

In the fourth quarter of 2014, the Company contributed its investments in four entities to Mammoth for a 30.5% interest in this entity. Mammoth originally intended to pursue its initial public offering in 2014 or 2015; however, due to low commodity prices, the offering was postponed. In October 2016, Mammoth converted from a limited partnership into a limited liability company named Mammoth Energy Partners LLC ("Mammoth LLC") and the Company and the other members of Mammoth LLC contributed their interests in Mammoth LLC to Mammoth Energy Services, Inc. ("Mammoth Energy"). The Company received 9,150,000 shares of Mammoth Energy common stock in return for its contribution. Following the contribution, Mammoth Energy completed its initial public offering (the "IPO") of 7,750,000 shares of its common stock at a public offering price of $15.00 per share, of which 7,500,000 shares were sold by Mammoth Energy and 250,000 shares were sold by certain selling stockholders, including 76,250 shares sold by the Company for which it received net proceeds of $1.1 million. At December 31, 2016, the Company owned an approximate 24.2% interest in Mammoth Energy. To reflect the dilution of the Company's shares of Mammoth Energy stock after the IPO, the Company recognized a gain of $3.4 million,

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which is included in loss (income) from equity method investments in the accompanying consolidated statements of operations. The Company's investment in Mammoth Energy was decreased by a $0.8 million foreign currency loss resulting from Mammoth Energy's foreign subsidiary for the year ended December 31, 2016. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

The Company accounted for the 2014 contribution to Mammoth as a sale of financial assets under FASB ASC 860. The Company estimated the fair market value of its investment in Mammoth as of the contribution date using an average of the market approach and the income approach, based on a independently prepared valuation of the contributed assets. The fair market value was reduced by a discount factor for lack of marketability due to the Company's minority interest, resulting in a fair value of $143.5 million for the Company's 30.5% interest. The fair value of the assets and liabilities acquired was estimated using assumptions that represent Level 3 inputs. See "Note 13 - Fair Value Measurements" for additional discussion of the measurement inputs. The Company recognized a gain of $84.5 million from its contribution of assets to Mammoth, which is included in gain on contribution of investments in the accompanying consolidated statements of operations.

The Company reviewed its investment in Mammoth Energy at December 31, 2016 and determined no impairment was needed. If commodity prices decline, an impairment of the investment in Mammoth Energy may result in the future.

Strike Force Midstream LLC

In February 2016, the Company, through its wholly owned subsidiary Gulfport Midstream Holdings, LLC ("Midstream Holdings"), entered into an agreement with Rice Midstream Holdings LLC ("Rice"), a subsidiary of Rice Energy Inc., to develop natural gas gathering assets in eastern Belmont County and Monroe County, Ohio (the "dedicated areas"). The Company contributed certain gathering assets for a 25% interest in the newly formed entity called Strike Force Midstream LLC ("Strike Force"). Rice acts as operator and owns the remaining 75% interest in Strike Force. Construction of the gathering assets, which is underway, is expected to provide gathering services for Gulfport operated wells and connectivity of existing dry gas gathering systems. During the year ended December 31, 2016, Gulfport paid $11.0 million in cash calls to Strike Force.

The Company accounted for its contribution to Strike Force at fair value under applicable codification guidance. The Company estimated the fair market value of its investment in Strike Force as of the contribution date using the discounted cash flow method under the income approach, based on an independently prepared valuation of the contributed assets. The fair market value was reduced by a discount factor for the lack of marketability due to the Company's minority interest, resulting in a fair value of $22.5 million for the Company's 25% interest. The fair value of the assets contributed was estimated using assumptions that represent Level 3 inputs. See Note 13 - Fair Value Measurements for additional discussion of the measurement inputs. The Company has elected to report its proportionate share of Strike Force's earnings on a one-quarter lag as permitted under FASB ASC 323. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

5. VARIABLE INTEREST ENTITIES

As of December 31, 2016, the Company held variable interests in the following variable interest entities ("VIEs"), but was not the primary beneficiary: Stingray Energy, Stingray Cementing, Sturgeon, Midstream and Timber Wolf. These entities have governing provisions that are the functional equivalent of a limited partnership and are considered VIEs because the limited partners or non-managing members lack substantive kick-out or participating rights which causes the equity owners, as a group, to lack a controlling financial interest. The Company is a limited partner or non-managing member in each of these VIEs and is not the primary beneficiary because it does not have a controlling financial interest. The general partner or managing member has power to direct the activities that most significantly impact the VIEs' economic performance. The Company also held a variable interest in Strike Force due to the fact that it does not have sufficient equity capital at risk. The Company is not the primary beneficiary of this entity. Prior to Mammoth's IPO, Mammoth was considered a variable interest entity. As a result of the IPO, Mammoth was incorporated and the Company determined that Mammoth is no longer a variable interest entity.

The Company accounts for its investment in these VIEs following the equity method of accounting. The carrying amounts of the Company's equity investments are classified as other non-current assets on the accompanying consolidated balance sheets. The Company's maximum exposure to loss as a result of its involvement with these VIEs is based on the Company’s capital contributions and the economic performance of the VIEs, and is equal to the carrying value of the Company’s investments which is the maximum loss the Company could be required to record in the consolidated statements of operations. See Note 4 for further discussion of these entities, including the carrying amounts of each investment.

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6. LONG-TERM DEBT

Long-term debt consisted of the following items as of December 31:

	2016	2015
	(In thousands)	
Revolving credit agreement (1)	$—	$—
Building loans (2)	—	1,653
7.75% senior unsecured notes due 2020 (3)	—	600,000
6.625% senior unsecured notes due 2023 (4)	350,000	350,000
6.000% senior unsecured notes due 2024 (5)	650,000	—
6.375% senior unsecured notes due 2025 (6)	600,000	—
Net unamortized original issue premium (discount) (7)	—	12,493
Net unamortized debt issuance costs (8)	(27,174)	(17,883)
Construction loan (9)	21,049	—
Less: current maturities of long term debt	(276)	(179)
Debt reflected as long term	$1,593,599	$946,084

Maturities of long-term debt (excluding premiums, discounts and unamortized debt issuance costs) as of December 31, 2016 are as follows:

	(In thousands)
2017	$276
2018	522
2019	586
2020	649
2021	712
Thereafter	1,618,304
Total	$1,621,049

(1) The Company has entered into a senior secured revolving credit facility as amended, with the Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The credit agreement provides for a maximum facility amount of $1.5 billion and matures on June 6, 2018. On February 19, 2016, the Company further amended its revolving credit facility to, among other things, (a) increase the basket for unsecured debt issuances to $1.4 billion from $1.2 billion (of which $950 million was then outstanding), (b) reaffirm the Company's borrowing base of $700.0 million, and (c) increase the percentage of projected oil and gas production that may be hedged by the Company during 2016. On December 13, 2016, the Company further amended its revolving credit facility to, among other things, (a) reset the maturity date to December 31, 2021, (b) adjust lenders, (c) increase the basket for unsecured debt issuances to $1.6 billion, (d) increase the interest rates by 50 basis points, (e) increase the mortgage requirement to 85% (from 80%), and (f) add deposit account control agreement language. As of December 31, 2016, the Company did not have any outstanding borrowing under the Amended and Restated Credit Agreement. At December 31, 2016, the total availability for future borrowings under Amended and Restated Credit Agreement, after giving effect to an aggregate of $209.7 million of letters of credit, was $490.3 million. The Company's wholly-owned subsidiaries have guaranteed the obligations of the Company under the Amended and Restated Credit Agreement.

Advances under the Amended and Restated Credit Agreement may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.00% to 2.00%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its “prime rate,” and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 2.00% to 3.00%, plus (2) the London interbank

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offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or service that displays on average London interbank offered rate as determined by ICE Benchmark Administration (or any other person that takes over administration of such rate) for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the "London Interbank Offered Rate" for deposits in U.S. dollars.

The Amended and Restated Credit Agreement contains customary negative covenants including, but not limited to, restrictions on the Company's and its subsidiaries' ability to:

•incur indebtedness;
•grant liens;
•pay dividends and make other restricted payments;
•make investments;
•make fundamental changes;
•enter into swap contracts and forward sales contracts;
•dispose of assets;
•change the nature of their business; and
•enter into transactions with affiliates.

The negative covenants are subject to certain exceptions as specified in the Amended and Restated Credit Agreement.

The Amended and Restated Credit Agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants:

(i) the ratio of net funded debt to EBITDAX (net income, excluding (i) any non-cash revenue or expense associated with swap contracts resulting from ASC 815 and (ii) any cash or noncash revenue or expense attributable to minority investments plus without duplication and, in the case of expenses, to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) exploration costs deducted in determining net income under successful efforts accounting, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings (provided that expenses related to any unsuccessful disposition will be limited to $3.0 million in the aggregate) for a twelve-month period may not be greater than 4.00 to 1.00; and

(ii) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00.

The Company was in compliance with all covenants at December 31, 2016.

(2) In March 2011, the Company entered into a new building loan agreement for the office building it occupies in Oklahoma City, Oklahoma. The new loan agreement refinanced the $2.4 million outstanding under the previous building loan agreement. The new agreement matured in February 2016 and bore interest at the rate of 5.82% per annum. The new building loan required monthly interest and principal payments of approximately $22,000 and was collateralized by the Oklahoma City office building and associated land. Subsequently, the loan was refinanced with a new interest rate of 4.00% per annum. The building loan matured in December 2018 and required monthly interest and principal payments of approximately $20,000. The Company paid the balance of the loan in full in February 2016.

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(3) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of Senior Notes due 2020 (the "October Notes") under an indenture among the Company, its subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, (the "senior note indenture"). On December 21, 2012, the Company issued an additional $50.0 million in aggregate principal amount of 7.75% Senior Notes due 2020 (the "December Notes") as additional securities under the senior note indenture. On August 18, 2014, the Company issued an additional $300.0 million in aggregate principal amount of 7.75% Senior Notes due 2020 (the "August Notes"). The August Notes were issued as additional securities under the senior note indenture. The October Notes, December Notes and the August Notes are collectively referred to as the "2020 Notes."

On October 6, 2016, the Company commenced a cash tender offer to purchase any and all of its 2020 Notes, which tender offer expired on October 13, 2016 and settled on October 14, 2016. Holders of the 2020 Notes that were validly tendered and accepted at or prior to the expiration time of the tender offer, or who delivered the 2020 Notes pursuant to the guaranteed delivery procedures, received total cash consideration of $1,042 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date. An aggregate of $403.5 million in principal amount of the 2020 Notes was validly tendered in the tender offer. The remaining 2020 Notes that were not tendered in the tender offer were redeemed by the Company. The redemption payment included approximately $196.5 million in aggregate principal amount at a redemption price of 103.875% of the principal amount of the redeemed 2020 Notes, plus accrued and unpaid interest thereon to the redemption date. Upon deposit of the redemption payment with the paying agent on October 14, 2016, the indenture governing the 2020 Notes was fully satisfied and discharged. The cash tender offer for the 2020 Notes and redemption of the remaining 2020 Notes were funded with the net proceeds from the offering of the 6.000% Senior Notes due 2024 (the “2024 Notes”) as discussed below and cash on hand.

(4) On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2023 (the "2023 Notes") to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act (the "2023 Notes Offering"). The Company received net proceeds of approximately $343.6 million after initial purchaser discounts and commissions and estimated offering expenses.

The 2023 Notes were issued under an indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee. Pursuant to the indenture relating to the 2023 Notes, interest on the 2023 Notes will accrue at a rate of 6.625% per annum on the outstanding principal amount thereof from April 21, 2015, payable semi-annually on May 1 and November 1 of each year, commencing on November 1, 2015. The 2023 Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries.

In connection with the 2023 Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the 2023 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the 2023 Notes was completed on October 13, 2015.

(5) On October 14, 2016, the Company issued the 2024 Notes in aggregate principal amount of $650.0 million. The 2024 Notes were issued under an indenture, dated as of October 14, 2016, among the Company, the subsidiary guarantors party thereto and the senior note indenture trustee (the "2024 Indenture"), to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act (the “2024 Notes Offering”). Under the 2024 Indenture, interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof from October 14, 2016, payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2017. The 2024 Notes will mature on October 15, 2024. The Company received approximately $638.9 million in net proceeds from the offering of the 2024 Notes, which was used, together with cash on hand, to purchase the outstanding 2020 Notes in a concurrent cash tender offer, to pay fees and expenses thereof, and to redeem any of the 2020 Notes that remained outstanding after the completion of the tender offer.

(6) On December 21, 2016, the Company issued $600.0 million in aggregate principal amount of 6.375% Senior Notes due 2025 (the “2025 Notes”). The 2025 Notes were issued under an indenture, dated as of December 21, 2016, among the Company, the subsidiary guarantors party thereto and the senior note indenture trustee (the "2025 Indenture"), to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. Under the 2025 Indenture, interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof from December 21, 2016, payable semi-annually on May 15 and November 15 of each year, commencing on May 15, 2017. The 2025 Notes will mature on May 15, 2025. The Company received approximately $590.8 million in net proceeds from the offering of the 2025 Notes, which the Company intends to use, together with the net proceeds from the Company's December 2016 common stock offering and cash on hand, to fund the cash portion

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of the purchase price for the pending acquisition of certain assets from Vitruvian II Woodford, LLC ("Vitruvian"). See Note 15 for more details on the pending Vitruvian Acquisition.

(7) The October Notes were issued at a price of 98.534% resulting in a gross discount of $3.7 million and an effective rate of 8.000%. The December Notes were issued at a price of 101.000% resulting in a gross premium of $0.5 million and an effective rate of 7.531%. The August Notes were issued at a price of 106.000% resulting in a gross premium of $18.0 million and an effective rate of 6.561%. The 2023 Notes, 2024 Notes, and 2025 Notes were issued at par. The premium and discount was amortized using the effective interest method until the bonds were redeemed, at which point the remaining premium and discount of $10.8 million was written off and is included in loss on debt extinguishment on the consolidated statements of operations.

(8) In accordance with ASU 2015-03, loan issuance cost related to the Notes have been presented as a reduction to the Notes. At December 31, 2016, total unamortized debt issuance costs were $6.0 million for the 2023 Notes, $10.9 million for the 2024 Notes, and $10.1 million for the 2025 Notes. In addition, loan commitment fee costs for the construction loan agreement described immediately below were $0.1 million at December 31, 2016.

(9) On June 4, 2015, the Company entered into a construction loan agreement (the "Construction Loan") with InterBank for the construction of a new corporate headquarters in Oklahoma City. The Construction Loan allows for maximum principal borrowings of $24.5 million and requires the Company to fund 30% of the cost of the construction before any funds can be drawn, which occurred in January 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum and is payable on the last day of the month through May 31, 2017. Monthly interest and principal payments are due beginning June 30, 2017, with the final payment due June 4, 2025. At December 31, 2016, the total borrowings under the Construction loan were approximately $21.0 million.

Interest Expense

The following schedule shows the components of interest expense for the year ended December 31:

	2016	2015	2014
	(In thousands)		
Cash paid for interest	$68,966	$59,736	$28,646
Change in accrued interest	1,768	4,011	3,875
Capitalized interest	(9,148)	(13,580)	(9,687)
Amortization of loan costs	3,660	3,219	1,685
Amortization of note discount and premium	(1,716)	(2,165)	(533)
Total interest expense	$63,530	$51,221	$23,986

The Company capitalized approximately $8.7 million and $13.3 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2016 and 2015, respectively. During the year ended December 31, 2016 and 2015, the Company also capitalized approximately $0.4 million and $0.3 million in interest expense related to building construction, respectively.

7. COMMON STOCK OPTIONS, RESTRICTED STOCK AND CHANGES IN CAPITALIZATION

Options

In January 2005, the Company adopted the 2005 Stock Incentive Plan (“2005 Plan”), which is administered by the Compensation Committee (the "Committee"). Under the terms of the 2005 Plan, the Committee may determine when options shall be granted, to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting periods of such options and the exercisable period of such options. Eligible participants are defined as employees, consultants, and directors of the Company.

On April 20, 2006, the Company amended and restated the 2005 Plan to (i) include (a) incentive stock options, (b) nonstatutory stock options, (c) restricted awards (restricted stock and restricted stock units), (d) performance awards and (e) stock appreciation rights and (ii) increase the maximum aggregate amount of common stock that may be issued under the

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2005 Plan from 1,904,606 shares to 3,000,000 shares, including the 627,337 shares underlying options granted to employees under the Plan prior to adoption of the 2005 Plan. As of December 31, 2016, the Company had granted 997,269 options for the purchase of shares of the Company's common stock and 1,143,217 shares of restricted stock under the 2005 Plan. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

On April 19, 2013, the Company amended and restated the 2005 Plan with the 2013 Restated Stock Incentive Plan ("2013 Plan"). The 2013 Plan increased the numbers of shares that may be awarded from 3,000,000 to 7,500,000 shares, including the 627,337 shares underlying options granted to employees under the Plan. The shares of stock issued once the options are exercised will be from authorized but unissued common stock. As of December 31, 2016, the Company had granted 1,062,207 shares of restricted stock under the 2013 Plan.

Sale of Common Stock

On April 21, 2015, the Company issued 10,925,000 shares of its common stock in an underwritten public offering. The net proceeds from this equity offering were approximately $501.8 million after underwriting discounts and commissions and offering expenses. The Company used a portion of these net proceeds, together with a portion of the net proceeds from its concurrent senior notes offering (see Note 6), to repay all amounts outstanding at that time under its revolving credit facility and to fund the acquisition of Paloma (see Note 2) and used the remaining net proceeds from these offerings for general corporate purposes, including the funding of a portion of its 2015 capital development plans.

On June 12, 2015, the Company issued 11,500,000 shares of its common stock in an underwritten public offering. The net proceeds from this equity offering were approximately $479.7 million after underwriting discounts and commissions and offering expenses. The Company used a portion of the net proceeds to fund the Monroe Acquisition (see Note 2) and used the remaining funds for general corporate purposes, including the funding of a portion of its 2015 capital development plans.

On March 15, 2016, the Company issued 16,905,000 shares of its common stock in an underwritten public offering (which included 2,205,000 shares sold pursuant to an option to purchase additional shares of the Company's common stock granted by the Company to, and exercised in full by, the underwriters). The net proceeds from this equity offering were approximately $411.7 million, after underwriting discounts and commissions and offering expenses. The Company intends to use the net proceeds from this offering primarily to fund a portion of its 2017 capital development plan and for general corporate purposes.

On December 21, 2016, the Company issued an aggregate 33,350,000 shares of its common stock in an underwritten public offering (which included 4,350,000 shares subject to an option to purchase additional shares exercised by the underwriters). The net proceeds from this equity offering were approximately $698.8 million, after deducting underwriting discounts and commissions and estimated offering expenses. The Company intends to use the net proceeds from this offering, together with the net proceeds from the offering of the 2025 Notes and cash on hand, to fund the cash portion of the purchase price for the pending Vitruvian Acquisition (see Note 15) and intends to use the remaining funds for general corporate purposes, including the funding of a portion of its capital development plans.

8. STOCK-BASED COMPENSATION

During the years ended December 31, 2016, 2015 and 2014 the Company's stock-based compensation cost was $12.3 million, $14.4 million and $14.9 million, respectively, of which the Company capitalized $4.9 million, $5.7 million and $5.9 million, respectively, relating to its exploration and development efforts.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. Expected volatilities are based on the historical volatility of the market price of Gulfport's common stock over a period of time ending on the grant date. Based upon the historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The 2013 Restated Stock Incentive Plan (which amended and restated the 2005 Plan) provides that all options must have an exercise price not less than the fair value of the Company's common stock on the date of the grant.

No stock options were issued during the years ended December 31, 2016, 2015 and 2014.

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. In each case, the actual value that will be realized, if any, depends on the future performance of the common

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stock and overall stock market conditions. There is no assurance that the value an optionee actually realizes will be at or near the value estimated using the Black-Scholes model.
A summary of the status of stock options and related activity for the years ended December 31, 2016, 2015 and 2014 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at January 1, 2014	210,241	$ 3.50	1.07	$ 12,538
Granted	—	—		
Exercised	(205,241)	3.36		12,822
Forfeited/expired	—	—		
Options outstanding at December 31, 2014	5,000	9.07	0.69	$ 163
Granted	—	—		
Exercised	(5,000)	9.07		124
Forfeited/expired	—	—		
Options outstanding at December 31, 2015	—	—	—	$ —
Granted	—	—		
Exercised	—	—		—
Forfeited/expired	—	—		
Options outstanding at December 31, 2016	—	$ —	—	$ —
Options exercisable at December 31, 2016	—	$ —	—	$ —

The following table summarizes restricted stock activity for the twelve months ended December 31, 2016, 2015 and 2014:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2014	463,637	$ 44.80
Granted	246,409	65.07
Vested	(272,665)	45.76
Forfeited	(50,136)	53.72
Unvested shares as of December 31, 2014	387,245	$ 55.87
Granted	352,605	$ 35.99
Vested	(236,812)	52.39
Forfeited	(18,799)	45.21
Unvested shares as of December 31, 2015	484,239	$ 43.51
Granted	451,241	$ 27.78
Vested	(252,566)	43.94
Forfeited	(69,858)	33.43
Unvested shares as of December 31, 2016	613,056	$ 32.90

Unrecognized compensation expense as of December 31, 2016 related to outstanding stock options and restricted shares was $14.3 million. The expense is expected to be recognized over a weighted average period of 1.60 years.

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9. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the building loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities.

At December 31, 2016, the carrying value of the outstanding debt represented by the Notes was $1.6 billion including the unamortized debt issuance cost of approximately $6.0 million related to the 2023 Notes, approximately $10.9 million related to the 2024 Notes, and approximately $10.1 million related to the 2025 Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $1.6 billion at December 31, 2016.

10. INCOME TAXES

The income tax provision consists of the following:

	2016	2015	2014
	(In thousands)		
Current:			
State	$(1,330)	$(1,069)	$14,384
Federal	(19,770)	(439)	16,039
Deferred:			
State	(386)	(14,218)	4,314
Federal	18,573	(240,275)	118,604
Total income tax (benefit) expense provision	$(2,913)	$(256,001)	$153,341

A reconciliation of the statutory federal income tax amount to the recorded expense follows:

	2016	2015	2014
	(In thousands)		
(Loss) income before federal income taxes	$(982,622)	$(1,480,885)	$400,744
Expected income tax at statutory rate	(343,918)	(518,310)	140,259
State income taxes	(5,883)	(15,908)	11,570
Other differences	4,293	(420)	1,512
Intraperiod tax allocation	(1,349)	—	—
Changes in valuation allowance	343,944	278,637	—
Income tax (benefit) expense recorded	$(2,913)	$(256,001)	$153,341

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The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2016, 2015 and 2014 are estimated as follows:

	2016	2015	2014
	(In thousands)		
Deferred tax assets:			
Net operating loss carryforward	$162,073	$46,209	$1,091
Oil and gas property basis difference	386,302	292,838	—
Investment in pass through entities	27,469	14,034	—
FASB ASC 718 compensation expense	2,084	1,922	1,562
Business energy investment tax credit	369	—	—
AMT credit	3,842	23,629	24,053
Charitable contributions carryover	303	146	150
Unrealized loss on hedging activities	48,317	—	—
Foreign tax credit carryforwards	2,074	2,074	2,074
Accrued liabilities	397	—	1,260
ARO liability	12,107	9,415	—
State net operating loss carryover	5,351	4,344	2,627
Total deferred tax assets	650,688	394,611	32,817
Valuation allowance for deferred tax assets	(645,841)	(303,246)	(13,522)
Deferred tax assets, net of valuation allowance	4,847	91,365	19,295
Deferred tax liabilities:			
Oil and gas property basis difference	—	—	183,767
Investment in pass through entities	—	—	27,938
Non-oil and gas property basis difference	155	715	849
Unrealized gain on hedging activities	—	66,422	37,006
Total deferred tax liabilities	155	67,137	249,560
Net deferred tax asset (liability)	$4,692	$24,228	$(230,265)

The Company has an available federal tax net operating loss carryforward estimated at approximately $463.1 million as of December 31, 2016. This carryforward will begin to expire in the year 2036. Based upon the December 31, 2016 net deferred tax asset position and a significant loss in 2016, management believes that there is sufficient negative evidence to place a valuation allowance on the net deferred tax asset that may not be utilized based upon a more likely than not basis. The Company also has state net operating loss carryovers of $111.9 million that will begin to expire in 2016, alternative minimum tax credits of $3.8 million with no expiration date and federal foreign tax credit carryovers of $2.1 million which begin to expire in 2017. The Company believes that it can utilize an Oklahoma state NOL as well as a portion of the AMT credit through carrybacks and a refundable election. Therefore, the Company has recorded a total valuation allowance of $645.8 million related to the remaining net deferred tax asset.

In 2014, the Company's sale of its remaining shares of Diamondback common stock, as well as its share of the proceeds from Blackhawk's sale of its interest in Ohio Gas Gathering Company, LLC and Ohio Condensate Company, LLC, generated $203.3 million and $83.7 million of taxable gain, respectively, resulting in a deferred tax expense of $79.4 million and $32.3 million, respectively. The Company's current federal tax benefit in 2016 and 2015 is primarily attributable to the Company recording a full cost ceiling impairment of $715.5 million and $1.4 billion against the oil and gas assets, while the federal tax expense in 2014 is a result of operations plus the sale of Diamondback common shares and the sale of assets by Blackhawk.

No amounts for state and federal income taxes payable were owed at December 31, 2016 and 2015.

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11. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net income per common share are presented in the tables below:

	For the Year Ended December 31,								
	2016			2015			2014		
	Loss	Shares	Per Share	Loss	Shares	Per Share	Income	Shares	Per Shar
	(In thousands, except share data)								
Basic:									
Net (loss) income	$(979,709)	122,952,866	$(7.97)	$(1,224,884)	99,792,401	$(12.27)	$247,403	85,445,963	$2.9
Effect of dilutive securities:									
Stock options and awards	—	—		—	—		—	367,219	
Diluted:									
Net (loss) income	$(979,709)	122,952,866	$(7.97)	$(1,224,884)	99,792,401	$(12.27)	$247,403	85,813,182	$2.8

There were 539,988 and 449,880 shares of common stock that were considered anti-dilutive for the years ended December 31, 2016 and 2015, respectively. There were no potential shares of common stock that were considered anti-dilutive for the year ended December 31, 2014.

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12. DERIVATIVE INSTRUMENTS

Natural Gas, Oil and Natural Gas Liquids Derivative Instruments

The Company seeks to reduce its exposure to unfavorable changes in natural gas, oil and natural gas liquids prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps and various types of option contracts. These contracts allow the Company to predict with greater certainty the effective oil, natural gas and natural gas liquids prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

Fixed price swaps are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. When the referenced settlement price is less than the price specified in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the volume. The prices contained in these fixed price swaps are based on the NYMEX Henry Hub for natural gas, Argus Louisiana Light Sweet Crude for oil, the NYMEX West Texas Intermediate for oil, and Mont Belvieu for propane and pentane. Below is a summary of the Company's open fixed price swap positions as of December 31, 2016.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2017	NYMEX Henry Hub	531,171	$ 3.17
2018	NYMEX Henry Hub	296,438	$ 3.10
2019	NYMEX Henry Hub	4,932	$ 3.37

	Location	Daily Volume (Bbls/day)	Weighted Average Price
2017	ARGUS LLS	1,748	$ 51.97
2017	NYMEX WTI	3,353	$ 54.98
2018	NYMEX WTI	899	$ 55.31

	Location	Daily Volume (Bbls/day)	Weighted Average Price
2017	Mont Belvieu C3	1,630	$ 25.70
2017	Mont Belvieu C5	250	$ 49.14

The Company sold call options and used the associated premiums to enhance the fixed price for a portion of the fixed price natural gas swaps listed above. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, the Company pays its counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volumes.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2017	NYMEX Henry Hub	60,068	$ 3.12
2018	NYMEX Henry Hub	4,932	$ 2.91

For a portion of the combined natural gas derivative instruments containing fixed price swaps and sold call options, the counterparty has an option to extend the terms an additional twelve months for the period January 2018 through December 2018. These options expire in December 2017. If executed, the Company would have additional fixed price swaps for 30,000 MMBtu per day with the option to double at a weighted average price of $3.36 and additional short call options for 30,000 MMBtu per day with the option to double at a weighted average ceiling price of $3.36.

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In addition, the Company has entered into natural gas basis swap positions, which settle on the pricing index to basis differential of Tetco M2 to the NYMEX Henry Hub natural gas price. As of December 31, 2016, the Company had the following natural gas basis swap positions for Tetco M2.

	Location	Daily Volume (MMBtu/day)	Weighted Average Price
2017	Tetco M2	12,329	$ (0.59)

Balance sheet presentation

The Company reports the fair value of derivative instruments on the consolidated balance sheets as derivative instruments under current assets, noncurrent assets, current liabilities, and noncurrent liabilities on a gross basis. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual trades. The following table presents the fair value of the Company's derivative instruments on a gross basis at December 31, 2016 and 2015:

	December 31,	
	2016	2015
	(In thousands)	
Short-term derivative instruments - asset	$3,488	$142,794
Long-term derivative instruments - asset	$5,696	$51,088
Short-term derivative instruments - liability	$119,219	$437
Long-term derivative instruments - liability	$26,759	$6,935

Gains and losses

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, the effective portion of changes in fair value are recognized in accumulated other comprehensive income (loss) and subsequently reclassified out of accumulated other comprehensive income (loss) into earnings as the underlying hedged transaction impacts earnings. The Company had no cash flow hedges in place for the years ended December 31, 2016, 2015 and 2014, as all fixed price swaps, swaptions and basis swaps had either been deemed ineffective at their inception or had been accounted for using the mark-to-market accounting method.

The following table presents the gain and loss recognized in Net (loss) gain on gas, oil and NGL derivatives in the accompanying consolidated statements of operations due to derivative instruments for the years ended December 31, 2016, 2015, and 2014.

	Gain (loss) on derivative instruments For the Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Natural gas derivatives	$(165,933)	$182,993	$103,128
Oil derivatives	(5,387)	19,201	6,171
Natural gas liquids derivatives	(3,186)	1,319	—
Total	$(174,506)	$203,513	$109,299

The Company delivered approximately 77% of its 2016 production under fixed price swaps.

Offsetting of derivative assets and liabilities

The following table presents the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets as of the dates presented, all at fair value.

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	As of December 31, 2016		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$9,184	$ (9,184)	$—
Derivative liabilities	$(145,978)	$ 9,184	$(136,794)

	As of December 31, 2015		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$193,882	$ (7,372)	$ 186,510
Derivative liabilities	$(7,372)	$ 7,372	$ —

Concentration of Credit Risk

By using derivative instruments that are not traded on an exchange, the Company is exposed to the credit risk of its counterparties. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. When the fair value of a derivative instrument is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The Company's derivative contracts are with multiple counterparties to lessen its exposure to any individual counterparty. Additionally, the Company uses master netting agreements to minimize credit risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. None of the Company's derivative instrument contracts contain credit-risk related contingent features. Other than as provided by the Company's revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under its derivative instruments, nor are the counterparties required to provide credit support to the Company.

13. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value in accordance with FASB ASC 820, "Fair Value Measurement and Disclosures" ("FASB ASC 820"). FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 – Significant inputs to the valuation model are unobservable.

Valuation techniques that maximize the use of observable inputs are favored. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

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The following tables summarize the Company's financial and non-financial liabilities by FASB ASC 820 valuation level as of December 31, 2016 and 2015:

	December 31, 2016		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$—	$9,184	$ —
Liabilities:			
Derivative Instruments	$—	$145,978	$ —

	December 31, 2015		
	Level 1	Level 2	Level 3
	(In thousands)		
Assets:			
Derivative Instruments	$—	$193,882	$ —
Liabilities:			
Derivative Instruments	$—	$7,372	$ —

The Company estimates the fair value of all derivative instruments industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.

The estimated fair values of proved oil and gas properties assumed in business combinations are based on a discounted cash flow model and market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk-adjusted discount rates. The estimated fair values of unevaluated oil and gas properties was based on geological studies, historical well performance, location and applicable mineral lease terms. Based on the unobservable nature of certain of the inputs, the estimated fair value of the oil and gas properties assumed is deemed to use Level 3 inputs. See Note 2 for further discussion of the Company's acquisitions.

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, "Asset Retirement and Environmental Obligations" ("FASB ASC 410"). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 3 for further discussion of the Company's asset retirement obligations. Asset retirement obligations incurred during the year ended December 31, 2016 were approximately $11.0 million.

Due to the unobservable nature of the inputs, the fair value of the Company's initial investment in Mammoth was estimated using assumptions that represent Level 3 inputs. The Company's estimated fair value of the investment as of the November 24, 2014 contribution date was $143.5 million. See Note 4 for further discussion of the Company's contribution to Mammoth.

Due to the unobservable nature of the inputs, the fair value of the Company's investment in Grizzly was estimated using assumptions that represent Level 3 inputs. The Company estimated the fair value of the investment as of March 31, 2016 to be approximately $39.1 million. See Note 4 for further discussion of the Company's investment in

Grizzly.

Due to the unobservable nature of the inputs, the fair value of the Company's investment in Strike Force was estimated using assumptions that represent Level 3 inputs. The Company's estimated fair value of the investment as of the February 1, 2016 contribution date was $22.5 million. See Note 4 for further discussion of the Company's contribution to Strike Force.

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14. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company has conducted business activities with certain related parties.

Stingray Cementing, which is 50% owned by the Company, provides well cementing services as discussed above in Note 4. At December 31, 2016 and 2015, the Company owed Stingray Cementing approximately $0.5 million and $2.1 million, respectively, related to these services. Approximately $6.3 million and $7.0 million of services provided by Stingray Cementing are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2016 and 2015, respectively.

Stingray Energy, which is 50% owned by the Company, provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites as discussed above in Note 4. At December 31, 2016 and 2015, the Company owed Stingray Energy approximately $3.6 million and $2.2 million, respectively, related to these services. Approximately $1.1 million and $2.2 million of services provided by Stingray Energy are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2016 and 2015, respectively. Approximately $11.0 million and $16.0 million of services provided by Stingray Energy are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2016 and 2015, respectively.

After completing the contributions to Mammoth and Mammoth Energy and Mammoth Energy's IPO, all as discussed above in Note 4, the Company owned an approximate 24.2% equity investment in Mammoth Energy. Approximately $110.5 million and $141.2 million of services provided by Mammoth Energy are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2016 and 2015, respectively. At December 31, 2016 and 2015, the Company owed Mammoth Energy approximately $23.5 million and $24.7 million, respectively, related to these services.

Strike Force, which is 25% owned by the Company, develops natural gas gathering assets in dedicated areas as discussed above in Note 4. At December 31, 2016 the Company owed approximately $1.6 million to Strike Force for these related services. Approximately $1.8 million of services provided by Strike Force are included in midstream gathering and processing on the accompanying consolidated statement of operations for the year ended December 31, 2016.

15. COMMITMENTS

Plugging and Abandonment Funds

In connection with the Company's acquisition in 1997 of the remaining 50% interest in its WCBB properties, the Company assumed the seller’s (Chevron) obligation to contribute approximately $18,000 per month through March 2004 to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company could access the trust for use in plugging and abandonment charges associated with the property, although it has not yet done so. As of December 31, 2016, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2016, the Company had plugged 513 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to 100% of their total compensation up to the maximum pre-tax threshold through salary deferrals. Also under the plan, the Company will make a contribution each calendar year on behalf of each employee equal to at least 3% of his or her salary, regardless of the employee’s participation in salary deferrals and may also make additional discretionary contributions. During the years ended December 31, 2016, 2015 and 2014, Gulfport incurred $1.7 million, $1.4 million, and $0.8 million, respectively, in contributions expense related to this plan.

Employment Agreements

Effective November 1, 2012, the Company entered into employment agreements with Messrs. James Palm, Mike Liddell, and Michael G. Moore, each with an initial three-year term expiring on November 1, 2015 subjected to automatic one-year extensions unless terminated by either party to the agreement at least 90 days prior to the end of the then current term. These

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agreements provided for minimum salary and bonus levels which were subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits.

Effective February 15, 2014, Gulfport's former Chief Executive Officer, Mr. Palm, retired and his employment agreement with the Company terminated. The Company entered into a separation agreement with Mr. Palm, under which agreement certain benefits are provided to, and obligations imposed on, Mr. Palm.

Mr. Liddell resigned as the Company's Chairman effective June 2013 at which date his employment agreement with Gulfport terminated. At that same time, the Company entered into a consulting agreement with Mr. Liddell. Mr. Liddell terminated his consulting agreement with the Company effective January 1, 2015.

On April 22, 2014, the Board of Directors appointed Mr. Moore as Chief Executive Officer of the Company. The Company and Mr. Moore entered into an amended and restated employment agreement. The agreement has a three-year term commencing effective April 22, 2014, which was amended effective as of April 29, 2015. The employment agreement, as amended and restated as of April 29, 2015, provides, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits.

On March 13, 2015, the Company entered into an employment agreement with Ross Kirtley, the Company's Chief Operating Officer. The agreement had a two-year term commencing effective April 22, 2014. This agreement provided, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits. On August 5, 2016, Mr. Kirtley’s employment as the Company's Chief Operating Officer terminated.

In connection with Mr. Kirtley’s termination, the Company entered into a separation and release agreement with Mr. Kirtley, dated as of November 2, 2016 (the “Separation Agreement”), pursuant to which the Company agreed to provide Mr. Kirtley with (i) the cash compensation specified in his employment agreement, (ii) health care benefits for Mr. Kirtley and his eligible dependents for up to eighteen (18) months following the termination date, (iii) his company vehicle, (iv) the vesting of 3,000 shares of restricted stock and (v) the vesting of 14,820 restricted stock units provided that such restricted stock units will be settled in four substantially equal annual installments beginning in March 2017 in accordance with the original vesting schedule. All other restricted stock and restricted stock unit awards granted to Mr. Kirtley were forfeited and terminated.

Under the Separation Agreement, Mr. Kirtley is subject to certain covenants regarding confidentiality, non-solicitation, non-competition, trade secrets, unfair competition and inventions. The Separation Agreement also contains customary waiver and release provisions pursuant to which Mr. Kirtley waived, released and discharged the Company and certain other related parties from any and all claims that Mr. Kirtley may have had against the Company or such other parties as of the date of the Separation Agreement.

On March 13, 2015, the Company entered into an employment agreement with Aaron Gaydosik, the Company's Chief Financial Officer. The agreement had a three-year term commencing effective August 11, 2014. This agreement provided, among other things, for a minimum salary level, subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's incentive plans and other employee benefits. Mr. Gaydosik's employment agreement was terminated upon his resignation as the Company's Chief Financial Officer, effective January 4, 2017. As provided in such employment agreement, upon resignation, Mr. Gaydosik was entitled to any of his earned but unpaid salary through the date of resignation. Any unvested awards granted to Mr. Gaydosik under the Company’s equity incentive plan lapsed.

The aggregated minimum commitment for future salary at December 31, 2016 under the above listed employment agreements was approximately $0.4 million.

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Firm Transportation Commitments

The Company had approximately 1,379,000 MMBtu per day of firm sales contracted with third parties. The table below presents these commitments at December 31, 2016 as follows:

	(MMBtu per day)
2017	516,000
2018	257,000
2019	226,000
2020	223,000
2021	126,000
Thereafter	31,000
Total	1,379,000

The Company also had approximately $3.8 billion of firm transportation contracted with third parties. The table below presents these commitments at December 31, 2016 as follows:

	(In thousands)
2017	$176,800
2018	237,101
2019	237,100
2020	237,100
2021	237,101
Thereafter	2,694,979
Total	$3,820,181

Operating Leases

The Company leases office facilities under non-cancellable operating leases exceeding one year. Future minimum lease commitments under these leases at December 31, 2016 are as follows:

	(In thousands)
2017	$ 583
2018	54
Total	$ 637

Presented below is rent expense for the years ended December 31, 2016, 2015 and 2014, respectively.

	For the years ended December 31,		
	2016	2015	2014
	(In thousands)		
Minimum rentals	$840	$759	$733
Less: Sublease rentals	—	8	15
	$840	$751	$718

Other Commitments

Effective October 1, 2014, the Company entered into a Sand Supply Agreement with Muskie that expires on September 30, 2018. Pursuant to this agreement, the Company has agreed to purchase annual and monthly amounts of

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proppant sand subject to exceptions specified in the agreement at a fixed price per ton, subject to certain adjustments, plus agreed costs and expenses. Failure by either Muskie or the Company to deliver or accept the minimum monthly amount results in damages calculated per ton based on the difference between the monthly obligation amount and the amount actually delivered or accepted, as applicable. The Company incurred $1.9 million and $0.3 million related to non-utilization fees during the year ended December 31, 2016 and December 31, 2015, respectively.

Effective October 1, 2014, the Company entered into an Amended and Restated Master Services Agreement for pressure pumping services with Stingray Pressure that expires on September 30, 2018. Pursuant to this agreement, Stingray Pressure has agreed to provide hydraulic fracturing, stimulation and related completion and rework services to the Company and the Company has agreed to pay Stingray Pressure a monthly service fee plus the associated costs of the services provided.

Future minimum commitments under these agreements at December 31, 2016 are as follows:

	(In thousands)
2017	$ 52,440
2018	39,330
Total	$ 91,770

Other Agreements

On December 13, 2016, the Company entered into a Purchase and Sale Agreement (the “Purchase Agreement”) with Vitruvian, an unrelated third-party seller, pursuant to which the Company agreed to acquire certain assets of the seller (the “Acquisition”). Under the terms of the Purchase Agreement, the purchase price for these assets will consist of approximately 23.9 million shares of the Company’s common stock and $1.4 billion of cash, subject to adjustment as described in the Purchase Agreement. The closing of the Acquisition is expected to occur during February 2017, however, the closing of the Acquisition remains subject to customary closing conditions, including the completion of due diligence and the satisfaction or waiver of the closing conditions set forth in the Purchase Agreement. The Company has funded the $185.0 million deposit required under the Purchase Agreement into an escrow account.

16. CONTINGENCIES

In two separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermillion on July 29, 2016, the Company was named as a defendant, among 26 oil and gas companies, in the Cameron Parish complaint and among more than 40 oil and gas companies in the Vermillion Parish complaint, or the Complaints. The Complaints were filed under the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder, which Gulfport referred to collectively as the CZM Laws, and allege that certain of the defendants’ oil and gas exploration, production and transportation operations associated with the development of the East Hackberry and West Hackberry oil and gas fields, in the case of the Cameron Parish complaint, and the Tigre Lagoon oil and gas field, in the case of the Vermillion Parish complaint, were conducted in violation of the CZM Laws. The Complaints allege that such activities caused substantial damage to land and waterbodies located in the coastal zone of the relevant Parish, including due to defendants’ design, construction and use of waste pits and the alleged failure to properly close the waste pits and to clear, re-vegetate, detoxify and return the property affected to its original condition, as well as the defendants’ alleged discharge of waste into the coastal zone. The Complaints also allege that the defendants’ oil and gas activities have resulted in the dredging of numerous canals, which had a direct and significant impact on the state coastal waters within the relevant Parish and that the defendants, among other things, failed to design, construct and maintain these canals using the best practical techniques to prevent bank slumping, erosion and saltwater intrusion and to minimize the potential for inland movement of storm-generated surges, which activities allegedly have resulted in the erosion of marshes and the degradation of terrestrial and aquatic life therein. The Complaints also allege that the defendants failed to re-vegetate, refill, clean, detoxify and otherwise restore these canals to their original condition. In these two petitions, the plaintiffs seek damages and other appropriate relief under the CZM Laws, including the payment of costs necessary to clear, re-vegetate, detoxify and otherwise restore the affected coastal zone of the relevant Parish to its original condition, actual restoration of such coastal zone to its original condition, and the payment of reasonable attorney fees and legal expenses and pre-judgment and post judgment interest.

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The Company was served with the Cameron complaint in early May 2016 and with the Vermillion Complaint in early September 2016. The Louisiana Attorney General and the Louisiana Department of Natural Resources intervened in both the Cameron Parish suit and the Vermillion Parish suit. Shortly after the Complaints were filed, certain defendants removed the cases to the lawsuit to the United States District Court for the Western District of Louisiana. In both cases, the plaintiffs have filed a motion to remand, but both Courts have stayed further proceedings on the motions to remand pending a ruling from the United States Court of Appeals, Fifth Circuit on similar jurisdictional issues in another matter. The plaintiffs have granted all defendants an extension of time to file responsive pleadings to the Complaints until the District Courts rule on the motions to remand. Gulfport has not had the opportunity to evaluate the applicability of the allegations made in such complaints to their operations. Due to the early stages of these matters, management cannot determine the amount of loss, if any, that may result.

Due to the nature of the Company's business, it is, from time to time, involved in routine litigation or subject to disputes or claims related to its business activities, including workers' compensation claims and employment related disputes. In the opinion of the Company's management, none of the pending litigation, disputes or claims against the Company, if decided adversely, will have a material adverse effect on its financial condition, cash flows or results of operations.

Insurance Proceeds

In September 2014, the Company settled its legacy surface contamination lawsuit with Reeds et al. Under the terms of the settlement agreement, Gulfport paid $18.0 million, which is included in litigation settlement in the accompanying consolidated statements of operations for the year ended December 31, 2014. For the years ended December 31, 2016 and 2015 the Company was reimbursed $5.7 million and $10.0 million, respectively, net of related legal fees by its insurance provider, which is included in insurance proceeds in the accompanying consolidated statements of operations.

Concentration of Credit Risk

Gulfport operates in the oil and natural gas industry principally in the states of Ohio and Louisiana with sales to refineries, re-sellers such as pipeline companies, and local distribution companies. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company’s results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. At December 31, 2016, Gulfport held cash in excess of insured limits in these banks totaling $1.5 billion.

During the year ended December 31, 2016, Gulfport sold approximately 68% and 10% of its natural gas production to BP Energy Company ("BP") and DTE Energy Trading, Inc. ("DTE"), respectively, 72% and 24% of its oil production to Shell Trading Company ("Shell") and Marathon Oil Corporation ("Marathon"), respectively, and 74% and 23% of its natural gas liquids production to MarkWest Utica EMG ("MarkWest"), and Antero Resources ("Antero"), respectively. During the year ended December 31, 2015, Gulfport sold approximately 79% and 14% of its natural gas production to BP and DTE, respectively, 90% and 10% of its oil production to Shell and Marathon, respectively, and 76% and 24% of its natural gas liquids production to MarkWest and Antero, respectively. During the year ended December 31, 2014, Gulfport sold approximately 40%, 32%, and 19% of its natural gas production to BP, DTE and Hess, respectively, 99% of its oil production to Shell, and 100% of its natural gas liquids production to MarkWest.

17. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012, December 21, 2012 and August 18, 2014, the Company issued an aggregate of $600.0 million of its 7.75% Senior Notes. The October Notes and the December Notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act. The October Notes, December Notes and the August Notes are collectively referred to as the "2020 Notes".

In connection with the issuance of the 2020 Notes, the Company and the subsidiary guarantors entered into registration rights agreements with the initial purchasers, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offer to exchange the 2020 Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the October Notes and December Notes was completed in October 2013 and the exchange offer for the August Notes was completed in March 2015. In October 2016, the Company

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repurchased (in a cash tender offer) or redeemed all of the 2020 Notes, of which $600.0 million in aggregate principal amount was then outstanding, with the net proceeds from the issuance of the 2024 Notes discussed below and cash on hand.

On April 21, 2015, the Company issued $350.0 million in aggregate principal amount of its 6.625% Senior Notes due 2023 (the "2023 Notes") to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. In connection with the April Notes Offering, the Company and its subsidiary guarantors entered into a registration rights agreement, dated as of April 21, 2015, pursuant to which the Company agreed to file a registration statement with respect to an offer to exchange the April Notes for a new issue of substantially identical debt securities registered under the Securities Act. The exchange offer for the April Notes was completed on October 13, 2015.

On October 14, 2016, the Company issued $650.0 million in aggregate principal amount of its 6.000% Senior Notes due 2024 (the "2024 Notes") to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. The net proceeds from the issuance of the 2024 Notes, together with cash on hand, were used to repurchase or redeem all of the then-outstanding 2020 Notes in October 2016.

On December 21, 2016, the Company issued $600.0 million in aggregate principal amount of its 6.375% Senior Notes due 2025 (the "2025 Notes") to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. The Company intends to use the net proceeds from the issuance of the 2025 Notes, together with the net proceeds from the December 2016 underwritten offering of the Company’s common stock and cash on hand, to fund the cash portion of the purchase price for the Acquisition.

The 2020 Notes were, and the 2023 Notes, the 2024 Notes and the 2025 Notes are, guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt (the "Guarantors"). The 2020 Notes were not, and the 2023 Notes, the 2024 Notes and the 2025 Notes are not, guaranteed by Grizzly Holdings, Inc. (the "Non-Guarantor"). The Guarantors are 100% owned by Gulfport (the "Parent"), and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive (loss) income and statements of cash flows are provided for the Parent, the Guarantors and the Non-Guarantor and include the consolidating adjustments and eliminations necessary to arrive at the information for the Company on a condensed consolidated basis. The information has been presented using the equity method of accounting for the Parent's ownership of the Guarantors and the Non-Guarantor.

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$1,273,882	$1,993	$ —	$—	$1,275,875
Restricted Cash	185,000	—	—	—	185,000
Accounts receivable - oil and gas	137,087	37,496	—	(37,822)	136,761
Accounts receivable - related parties	16	—	—	—	16
Accounts receivable - intercompany	449,517	1,151	—	(450,668)	—
Prepaid expenses and other current assets	6,230	1,409	—	—	7,639
Short-term derivative instruments	3,488	—	—	—	3,488
Total current assets	2,055,220	42,049	—	(488,490)	1,608,779
Property and equipment:					
Oil and natural gas properties, full-cost accounting	5,655,125	417,524	—	(729)	6,071,920
Other property and equipment	68,943	43	—	—	68,986
Accumulated depletion, depreciation, amortization and impairment	(3,789,746)	(34)	—	—	(3,789,780)
Property and equipment, net	1,934,322	417,533	—	(729)	2,351,126
Other assets:					
Equity investments and investments in subsidiaries	236,327	33,590	45,213	(71,210)	243,920
Long-term derivative instruments	5,696	—	—	—	5,696
Deferred tax asset	4,692	—	—	—	4,692
Other assets	8,932	—	—	—	8,932
Total other assets	255,647	33,590	45,213	(71,210)	263,240
Total assets	$4,245,189	$493,172	$ 45,213	$(560,429)	$4,223,145
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$255,966	$9,158	$ —	$—	$265,124
Accounts payable - intercompany	31,202	457,163	126	(488,491)	—
Asset retirement obligation	195	—	—	—	195
Derivative instruments	119,219	—	—	—	119,219
Current maturities of long-term debt	276	—	—	—	276
Total current liabilities	406,858	466,321	126	(488,491)	384,814
Long-term derivative instrument	26,759	—	—	—	26,759
Asset retirement obligation	34,081	—	—	—	34,081
Long-term debt, net of current maturities	1,593,599	—	—	—	1,593,599
Total liabilities	2,061,297	466,321	126	(488,491)	2,039,253
Stockholders' equity:					
Common stock	1,588	—	—	—	1,588
Paid-in capital	3,946,442	33,822	257,026	(290,848)	3,946,442
Accumulated other comprehensive (loss) income	(53,058)	—	(50,931)	50,931	(53,058)
Retained (deficit) earnings	(1,711,080)	(6,971)	(161,008)	167,979	(1,711,080)
Total stockholders' equity	2,183,892	26,851	45,087	(71,938)	2,183,892

Total liabilities and stockholders' equity	$4,245,189	$493,172	$ 45,213	$(560,429)	$4,223,145

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CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets					
Cash and cash equivalents	$112,494	$479	$ 1	$—	$112,974
Accounts receivable - oil and gas	72,241	54	—	(423)	71,872
Accounts receivable - related parties	16	—	—	—	16
Accounts receivable - intercompany	326,475	60	—	(326,535)	—
Prepaid expenses and other current assets	3,905	—	—	—	3,905
Short-term derivative instruments	142,794	—	—	—	142,794
Total current assets	657,925	593	1	(326,958)	331,561
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	5,108,258	316,813	—	(729)	5,424,342
Other property and equipment	33,128	43	—	—	33,171
Accumulated depletion, depreciation, amortization and impairment	(2,829,081)	(29)	—	—	(2,829,110)
Property and equipment, net	2,312,305	316,827	—	(729)	2,628,403
Other assets:					
Equity investments and investments in subsidiaries	231,892	—	50,644	(40,143)	242,393
Long-term derivative instruments	51,088	—	—	—	51,088
Deferred tax asset	74,925	—	—	—	74,925
Other assets	6,364	—	—	—	6,364
Total other assets	364,269	—	50,644	(40,143)	374,770
Total assets	$3,334,499	$317,420	$ 50,645	$(367,830)	$3,334,734
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$264,893	$527	$ —	$(292)	$265,128
Accounts payable - intercompany	—	326,541	124	(326,665)	—
Asset retirement obligation	75	—	—	—	75
Derivative instruments	437	—	—	—	437
Deferred tax liability	50,697	—	—	—	50,697
Current maturities of long-term debt	179	—	—	—	179
Total current liabilities	316,281	327,068	124	(326,957)	316,516
Long-term derivative instrument	6,935	—	—	—	6,935
Asset retirement obligation	26,362	—	—	—	26,362
Long-term debt, net of current maturities	946,084	—	—	—	946,084
Total liabilities	1,295,662	327,068	124	(326,957)	1,295,897
Stockholders' equity:					
Common stock	1,082	—	—	—	1,082
Paid-in capital	2,824,303	322	241,553	(241,875)	2,824,303

Accumulated other comprehensive (loss) income	(55,177)	—	(55,177)	55,177	(55,177)
Retained (deficit) earnings	(731,371)	(9,970)	(135,855)	145,825	(731,371)
Total stockholders' equity	2,038,837	(9,648)	50,521	(40,873)	2,038,837
Total liabilities and stockholders' equity	$3,334,499	$317,420	$ 50,645	$(367,830)	$3,334,734

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 381,931	$ 3,979	$ —	$ —	$ 385,910
Costs and expenses:					
Lease operating expenses	68,034	843	—	—	68,877
Production taxes	13,121	155	—	—	13,276
Midstream gathering and processing	165,400	572	—	—	165,972
Depreciation, depletion and amortization	245,970	4	—	—	245,974
Impairment of oil and gas properties	715,495	—	—	—	715,495
General and administrative	43,896	(490)	3	—	43,409
Accretion expense	1,057	—	—	—	1,057
	1,252,973	1,084	3	—	1,254,060
(LOSS) INCOME FROM OPERATIONS	(871,042)	2,895	(3)	—	(868,150)
OTHER (INCOME) EXPENSE:					
Interest expense	63,529	1	—	—	63,530
Interest income	(1,230)	—	—	—	(1,230)
Insurance proceeds	(5,718)	—	—	—	(5,718)
Loss on debt extinguishment	23,776	—	—	—	23,776
Loss (income) from equity method investments and investments in subsidiaries	31,078	(89)	25,150	(22,154)	33,985
Other expense (income)	145	(16)	—	—	129
	111,580	(104)	25,150	(22,154)	114,472
(LOSS) INCOME BEFORE INCOME TAXES	(982,622)	2,999	(25,153)	22,154	(982,622)
INCOME TAX BENEFIT	(2,913)	—	—	—	(2,913)
NET (LOSS) INCOME	$ (979,709)	$ 2,999	$ (25,153)	$ 22,154	$ (979,709)

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$707,868	$ 1,122	$ —	$ —	$708,990
Costs and expenses:					
Lease operating expenses	68,632	843	—	—	69,475
Production taxes	14,618	122	—	—	14,740
Midstream gathering and processing	138,526	64	—	—	138,590
Depreciation, depletion and amortization	337,689	5	—	—	337,694
Impairment of oil and gas properties	1,440,418	—	—	—	1,440,418
General and administrative	41,892	55	20	—	41,967
Accretion expense	820	—	—	—	820
	2,042,595	1,089	20	—	2,043,704
(LOSS) INCOME FROM OPERATIONS	(1,334,727)	33	(20)	—	(1,334,714)
OTHER (INCOME) EXPENSE:					
Interest expense	51,221	—	—	—	51,221
Interest income	(643)	—	—	—	(643)
Insurance proceeds	(10,015)	—	—	—	(10,015)
Loss (income) from equity method investments and investments in subsidiaries	107,252	—	115,544	(116,703)	106,093
Other expense (income)	(1,657)	(346)	—	1,518	(485)
	146,158	(346)	115,544	(115,185)	146,171
(LOSS) INCOME BEFORE INCOME TAXES	(1,480,885)	379	(115,564)	115,185	(1,480,885)
INCOME TAX BENEFIT	(256,001)	—	—	—	(256,001)
NET (LOSS) INCOME	$(1,224,884)	$ 379	$ (115,564)	$ 115,185	$(1,224,884)

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CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$668,961	$ 1,801	$ —	$ —	$ 670,762
Costs and expenses:					
Lease operating expenses	51,238	953	—	—	52,191
Production taxes	23,803	203	—	—	24,006
Midstream gathering and processing	64,402	65	—	—	64,467
Depreciation, depletion and amortization	265,428	3	—	—	265,431
General and administrative	37,846	446	(2)	—	38,290
Accretion expense	761	—	—	—	761
Gain on sale of assets	(11)	—	—	—	(11)
	443,467	1,670	(2)	—	445,135
INCOME FROM OPERATIONS	225,494	131	2	—	225,627
OTHER (INCOME) EXPENSE:					
Interest expense	23,986	—	—	—	23,986
Interest income	(195)	—	—	—	(195)
Litigation settlement	25,500	—	—	—	25,500
Gain on contribution of investments	(84,470)	—	—	—	(84,470)
(Income) loss from equity method investments and investments in subsidiaries	(139,965)	—	13,159	(12,628)	(139,434)
Other (income) expense	(106)	(398)	—	—	(504)
	(175,250)	(398)	13,159	(12,628)	(175,117)
INCOME (LOSS) BEFORE INCOME TAXES	400,744	529	(13,157)	12,628	400,744
INCOME TAX EXPENSE	153,341	—	—	—	153,341
NET INCOME (LOSS)	$247,403	$ 529	$ (13,157)	$ 12,628	$ 247,403

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CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(Amounts in thousands)

	Year Ended December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(979,709)	$ 2,999	$ (25,153)	$ 22,154	$ (979,709)
Foreign currency translation adjustment	2,119	778	1,341	(2,119)	2,119
Other comprehensive income (loss)	2,119	778	1,341	(2,119)	2,119
Comprehensive (loss) income	$(977,590)	$ 3,777	$ (23,812)	$ 20,035	$ (977,590)

	Year Ended December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net (loss) income	$(1,224,884)	$ 379	$ (115,564)	$ 115,185	$(1,224,884)
Foreign currency translation adjustment	(28,502)	—	(28,502)	28,502	(28,502)
Other comprehensive (loss) income	(28,502)	—	(28,502)	28,502	(28,502)
Comprehensive (loss) income	$(1,253,386)	$ 379	$ (144,066)	$ 143,687	$(1,253,386)

	Year Ended December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$247,403	$ 529	$ (13,157)	$ 12,628	$ 247,403
Foreign currency translation adjustment	(16,894)	—	(16,894)	16,894	$ (16,894)
Other comprehensive (loss) income	(16,894)	—	(16,894)	16,894	(16,894)
Comprehensive income (loss)	$230,509	$ 529	$ (30,051)	$ 29,522	$ 230,509

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CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Year Ended December 31, 2016				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$336,330	$(9,486)	$(2)	$11,001	$337,843
Net cash (used in) provided by investing activities	(905,582)	(22,500)	(15,472)	37,972	(905,582)
Net cash provided by (used in) financing activities	1,730,640	33,500	15,473	(48,973)	1,730,640
Net increase (decrease) in cash and cash equivalents	1,161,388	1,514	(1)	—	1,162,901
Cash and cash equivalents at beginning of period	112,494	479	1	—	112,974
Cash and cash equivalents at end of period	$1,273,882	$1,993	$ —	$ —	$1,275,875

	Year Ended December 31, 2015				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$344,018	$(21,839)	$(2)	$2	$322,179
Net cash (used in) provided by investing activities	(1,595,767)	21,514	(14,472)	14,472	(1,574,253)
Net cash provided by (used in) financing activities	1,222,708	—	14,474	(14,474)	1,222,708
Net decrease in cash and cash equivalents	(29,041)	(325)	—	—	(29,366)
Cash and cash equivalents at beginning of period	141,535	804	1	—	142,340
Cash and cash equivalents at end of period	$112,494	$479	$1	$ —	$112,974

	Year Ended December 31, 2014				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$388,177	$21,698	$(2)	$ —	$409,873
Net cash (used in) provided by investing activities	(1,108,241)	(28,419)	(18,799)	18,802	(1,136,657)
Net cash provided by (used in) financing activities	410,168	—	18,802	(18,802)	410,168
Net (decrease) increase in cash and cash equivalents	(309,896)	(6,721)	1	—	(316,616)
Cash and cash equivalents at beginning of period	451,431	7,525	—	—	458,956

Cash and cash equivalents at end of period	$ 141,535	$ 804	$ 1	$ —	$ 142,340

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18. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (UNAUDITED)

The Company owns a 24.9999% interest in Grizzly, which interest is shown below.

The following is historical revenue and cost information relating to the Company's oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities

	2016	2015
	(In thousands)	
Proven properties	$4,491,615	$3,606,641
Unproven properties	1,580,305	1,817,701
	6,071,920	5,424,342
Accumulated depreciation, depletion, amortization and impairment reserve	(3,778,043)	(2,820,113)
Net capitalized costs	$2,293,877	$2,604,229
Equity investment in Grizzly Oil Sands ULC		
Proven properties	$70,266	$81,473
Unproven properties	80,892	82,388
	151,158	163,861
Accumulated depreciation, depletion, amortization and impairment reserve	(1,578)	(1,531)
Net capitalized costs	$149,580	$162,330

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2016	2015	2014
	(In thousands)		
Acquisition	$152,887	$810,755	$440,288
Development of proved undeveloped properties	423,998	642,811	864,511
Exploratory	—	—	2,249
Recompletions	16,386	13,894	45,658
Capitalized asset retirement obligation	10,971	8,800	2,095
Total	$604,242	$1,476,260	$1,354,801
Equity investment in Grizzly Oil Sands ULC			
Acquisition	$357	$396	$1,230
Development of proved undeveloped properties	—	47	7,107
Exploratory	—	—	—
Capitalized asset retirement obligation	784	282	1,055
Total	$1,141	$725	$9,392

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Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	2016	2015	2014
	(In thousands)		
Revenues	$385,910	$708,990	$670,762
Production costs	(248,125)	(222,805)	(140,664)
Depletion	(243,098)	(335,288)	(263,946)
Impairment	(715,495)	(1,440,418)	—
	(820,808)	(1,289,521)	266,152
Income tax (benefit) expense			
Current	—	—	—
Deferred	—	(220,201)	96,061
	—	(220,201)	96,061
Results of operations from producing activities	$(820,808)	$(1,069,320)	$170,091
Depletion per Mcf of gas equivalent (Mcfe)	$0.92	$1.68	$3.01

	2016	2015	2014
Results of Operations from equity method investment in Grizzly Oil Sands ULC			
Revenues	$—	$1,436	$5,449
Production costs	(13)	(1,549)	(10,113)
Depletion	—	(625)	(1,195)
	(13)	(738)	(5,859)
Income tax expense	—	—	—
Results of operations from producing activities	$(13)	$(738)	$(5,859)

Oil and Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2016, 2015 and 2014 and changes in proved reserves during the last three years. The reserve reports use an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2016, 2015 and 2014, in accordance with guidelines of the SEC applicable to reserves estimates. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for gas are stated in millions of cubic feet (MMcf). The prices used for the 2016 reserve report are $42.75 per barrel of oil, $2.48 per MMbtu and $9.91 per barrel for NGLs, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2015 and 2014 for reserve report purposes are $50.28 per barrel, $2.59 per MMbtu and $13.21 per barrel for NGLs and $94.99 per barrel, $4.35 per MMbtu and $44.84 per barrel for NGLs, respectively.

Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

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	2016			2015			2014		
	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)
Proved Reserves									
Beginning of the period	6,458	1,560,145	17,736	9,497	719,006	26,268	8,346	146,446	5,675
Purchases in oil and gas reserves in place	—	—	—	—	371,663	—	173	8,863	353
Extensions and discoveries	1,217	1,082,220	7,677	2,413	997,057	5,486	4,975	629,151	22,594
Revisions of prior reserve estimates	(3)	(247,703)	(1,439)	(2,553)	(371,430)	(9,594)	(1,313)	(6,136)	(304)
Current production	(2,126)	(227,594)	(3,847)	(2,899)	(156,151)	(4,424)	(2,684)	(59,318)	(2,050)
End of period	5,546	2,167,068	20,127	6,458	1,560,145	17,736	9,497	719,006	26,268
Proved developed reserves	4,882	744,797	14,299	6,120	652,961	12,910	5,719	345,166	12,379
Proved undeveloped reserves	664	1,422,271	5,828	338	907,184	4,826	3,778	373,840	13,889
Equity investment in Grizzly Oil Sands ULC									
Beginning of the period	—	—	—	14,558	—	—	13,637	—	—
Purchases in oil and gas reserves in place	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	—	—	—	—	—	—	—	—
Revisions of prior reserve estimates	—	—	—	(14,530)	—	—	990	—	—
Current production	—	—	—	(28)	—	—	(69)	—	—
End of period	—	—	—	—	—	—	14,558	—	—
Proved developed reserves	—	—	—	—	—	—	1,632	—	—
Proved undeveloped reserves	—	—	—	—	—	—	12,926	—	—

In 2016, the Company experienced extensions and discoveries of 1.1 Tcfe of estimated proved reserves attributable to the continued development of the Company's Utica Shale acreage. The Company experienced downward revisions of 227.9 Bcfe due to lower commodity prices on 67 PUD locations, including the loss of 35 of the 67 PUD locations as they were no longer economic, as well as downward revisions of 17.4 Bcfe due to rescheduling the drilling timeline of four PUD locations in excess of five years of initial booking resulting in the removal of these four PUD locations. In addition, the Company experienced upward revisions of 26.7 Bcfe attributable to improved performance of 34 PUD locations as a result of 14.5% production increases due to well performance of offset producers as well as lower lease operated and capital expenditures. In 2015, the Company experienced extensions and discoveries of 1,044.5 Bcfe of estimated proved reserves attributable to the continued development of the Company's Utica Shale acreage. In addition, the Company experienced downward revisions of 444,314 MMcfe in estimated proved reserves in 2015 primarily due to the exclusion of PUD locations in its Utica and Southern Louisiana fields that became uneconomic due to the continued decline in commodity prices. In 2015, the Company also purchased 371,663 MMcfe of proved reserves as a result of acquisitions from Paloma and AEU discussed above in Note 2. In 2014, the Company experienced extensions and discoveries of 786,347 MMcfe of estimated proved reserves attributable to the development of the Company's Utica Shale acreage. In addition, the Company experienced downward revisions of 15,837 MMcfe in estimated proved reserves in 2014 primarily due to the exclusion of PUD locations in our Southern Louisiana and Utica fields that were not expected to be drilled within five years of initial booking. The Company also purchased 12,019 MMcfe of proved reserves as a result of its acquisition from Rhino Exploration LLC.

Discounted Future Net Cash Flows

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The following tables present the estimated future cash flows, and changes therein, from Gulfport's proven oil and gas reserves as of December 31, 2016, 2015 and 2014 using an unweighted average first-of-the-month price for the period January through December 31, 2016, 2015 and 2014.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year ended December 31,		
	2016	2015	2014
	(In thousands)		
Future cash flows	$3,354,168	$3,043,450	$4,667,678
Future development and abandonment costs	(1,165,025)	(877,660)	(719,898)
Future production costs	(924,167)	(941,243)	(880,427)
Future production taxes	(69,447)	(58,169)	(71,229)
Future income taxes	(14,545)	(2,648)	(693,154)
Future net cash flows	1,180,984	1,163,730	2,302,970
10% discount to reflect timing of cash flows	(492,944)	(399,399)	(875,803)
Standardized measure of discounted future net cash flows	$688,040	$764,331	$1,427,167
Equity investment in Grizzly Oil Sands ULC Standardized measure of discounted cash flows			
Future cash flows	$—	$—	$754,720
Future development and abandonment costs	—	—	(205,242)
Future production costs	—	—	(291,988)
Future production taxes	—	—	—
Future income taxes	—	—	(11,250)
Future net cash flows	—	—	246,240
10% discount to reflect timing of cash flows			(152,494)
Standardized measure of discounted future net cash flows	$—	$—	$93,746

In order to develop its proved undeveloped reserves according to the drilling schedule used by the engineers in Gulfport's reserve report, the Company will need to spend $401.5 million, $331.4 million and $192.7 million during years 2017, 2018 and 2019, respectively.

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Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year ended December 31,		
	2016	2015	2014
	(In thousands)		
Sales and transfers of oil and gas produced, net of production costs	$(312,291)	$(486,185)	$(530,098)
Net changes in prices, production costs, and development costs	(146,518)	(1,412,181)	97,716
Acquisition of oil and gas reserves in place	—	83,340	14,266
Extensions and discoveries	186,909	262,895	790,533
Previously estimated development costs incurred during the period	176,218	117,540	68,227
Revisions of previous quantity estimates, less related production costs	(38,448)	(98,162)	(37,801)
Accretion of discount	76,433	142,717	57,847
Net changes in income taxes	(6,495)	412,240	(295,226)
Change in production rates and other	(12,099)	314,960	683,237
Total change in standardized measure of discounted future net cash flows	$(76,291)	$(662,836)	$848,701
Equity investment in Grizzly Oil Sands ULC Changes in standardized measure of discounted cash flows			
Sales and transfers of oil and gas produced, net of production costs	$—	$114	$4,664
Net changes in prices, production costs, and development costs	—	—	(76,518)
Acquisition of oil and gas reserves in place	—	—	—
Extensions and discoveries	—	—	7,107
Previously estimated development costs incurred during the period	—	47	—
Revisions of previous quantity estimates, less related production costs	—	(103,282)	10,659
Accretion of discount	—	9,375	14,946
Net changes in income taxes	—	—	9,162
Change in production rates and other	—	—	(25,738)
Total change in standardized measure of discounted future net cash flows	$—	$(93,746)	$(55,718)

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19. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2016 and 2015:

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$156,961	$(28,158)	$193,691	$63,416
Loss from operations	(195,794)	(323,412)	(157,995)	(190,949)
Income tax (benefit) expense	(191)	(157)	(3,407)	842
Net loss	(242,267)	(339,776)	(157,296)	(240,370)
Loss per share:				
Basic	$(2.17)	$(2.71)	$(1.25)	$(1.86)
Diluted	$(2.17)	$(2.71)	$(1.25)	$(1.86)

	2015			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$176,077	$112,294	$230,393	$190,226
Income (loss) from operations	28,533	(21,620)	(529,252)	(812,375)
Income tax expense (benefit)	14,479	(17,214)	(216,603)	(36,663)
Net income (loss)	25,519	(31,325)	(388,209)	(830,869)
Income (loss) per share:				
Basic	$0.30	$(0.32)	$(3.59)	$(7.67)
Diluted	$0.30	$(0.32)	$(3.59)	$(7.67)

20. SUBSEQUENT EVENTS

Derivatives

In January and February 2017, the Company entered into fixed price swaps for 2017 for approximately 23,000 MMBtu of natural gas per day at a weighted average price of $3.44 per MMbtu and for approximately 1,000 Bbls of C3 propane per day at a weighted average price of $28.56 per Bbl. For 2018, the Company entered into fixed price swaps for approximately 87,000 MMBtu of natural gas per day at a weighted average price of $3.19 per MMBtu. The Company's fixed price swap contracts are tied to the commodity prices on NYMEX for natural gas and Mont Belvieu for propane. The Company will receive the fixed priced amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas or Mont Belvieu for propane.

In addition, the Company entered into natural gas basis swap positions, which settle on the pricing index to basis differential of NPGL MC to the NYMEX Henry Hub natural gas price. In January and February 2017, the Company entered into natural gas basis swap positions for 2017 for approximately 38,000 MMBtu of natural gas per day at a weighted average differential of $0.26 per MMBtu. For 2018, the Company entered into natural gas basis swap positions for approximately 12,000 MMBtu of natural gas per day at a weighted average differential of $0.26 per MMBtu.

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EXHIBITS INDEX

Exhibit Number	Description
2.1##	Purchase and Sale Agreement, dated as of December 13, 2016, by and among Gulfport Energy Corporation, SCOOP Acquisition Company, LLC and Vitruvian II Woodford, LLC (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 15, 2016).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
3.5	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.6	Second Amendment to the Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 2, 2014).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company’s 6.625% Senior Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 21, 2015).
4.3	Indenture, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation’s 6.000% Senior Notes due 2024) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 19, 2016).
4.4	Registration Rights Agreement, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC and Scotia Capital (USA) Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 19, 2016).
4.5	

	Indenture, dated as of December 21, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.375% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 21, 2016).
4.6	Registration Rights Agreement, dated as of December 21, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 21, 2016).
4.7	Voting Rights Waiver Agreement, dated June 10, 2015, by and among Gulfport Energy Corporation, Putnam Investment Management, LLC, The Putnam Advisory Company, LLC and Putnam Fiduciary Trust Company (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 12, 2015).
10.1+	2013 Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form S-4, File No. 333-189992, filed by the Company with the SEC on July 17, 2013).
10.2+	2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 7, 2014).
10.3+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).

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10.4+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to the Form 10-K, File No. 000-19514, filed by the Company with the SEC on February 28, 2014).
10.5+	Consulting Agreement, effective as of June 14, 2013, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 19, 2013).
10.6+	Separation and Release Agreement, dated as of January 31, 2014, by and between the Company and James D. Palm (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 4, 2014).
10.7+	Amended and Restated Employment Agreement, dated as of April 29, 2015, by and between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 7, 2015).
10.8	Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 3, 2014).
10.9	First Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 28, 2014).
10.10	Second Amendment to Amended and Restated Credit Agreement, dated as of November 26, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 3, 2014).
10.11	Third Amendment to Amended and Restated Credit Agreement, dated as of April 10, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 15, 2015).
10.12	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 29, 2015, among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on August 7, 2015).
10.13	Fifth Amendment to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on September 24, 2015).

10.14	Sixth Amendment, dated February 19, 2016, to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 5, 2016).
10.15	Seventh Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2016, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 15, 2016).
10.16#	Sand Supply Agreement, effective as of October 1, 2014, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).
10.17#	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 5, 2015).
10.18#	Amended and Restated Master Services Agreement, effective as of October 1, 2014, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC (incorporated by reference to Exhibit 10.2 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 7, 2014).

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10.19#	Amendment to Amended and Restated Master Services Agreement, dated as of February 18, 2016 to be effective as of January 1, 2016, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC.
10.20+	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-4, File No. 333-199905, filed by the Company with the SEC on November 6, 2014).
10.21+	Separation and Release Agreement by and between Gulfport Energy Corporation and Ross Kirtley entered into November 2, 2016 (incorporated by reference to Exhibit 10.1 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 3, 2016).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
23.4*	Consent of Grant Thornton LLP with respect to financial statements of Diamondback Energy, Inc.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.

101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** Furnished herewith, not filed.

\+ Management contract, compensatory plan or arrangement.

\# Confidential treatment with respect to certain portions of this agreement was granted by the SEC which portions have been omitted and filed separately with the SEC.

\## The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission.

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