

Titan Energy, LLC
Form 10-K
April 17, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF
1934

For the transition period from to

Commission file number: 001-35317

TITAN ENERGY, LLC

(Exact name of registrant as specified in its charter)

Delaware	90-0812516
(State or other jurisdiction or	(I.R.S. Employer
incorporation or organization)	Identification No.)
Park Place Corporate Center One	15275
1000 Commerce Drive, Suite 400	

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Pittsburgh, PA
(Address of principal executive offices) Zip code

Registrant's telephone number, including area code: 800-251-0171

Securities registered pursuant to Section 12(b) of the Act:

None

Securities registered pursuant to Section 12(g) of the Act:

Common shares representing limited liability company interests

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer", "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company
Emerging growth company

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

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The aggregate market value of the voting and non-voting equity securities held by non-affiliates of the registrant, based on the closing price of the registrant's predecessor's common units on the last business day of the registrant's most recently completed second quarter, June 30, 2016, was approximately \$43.4 million.

The number of outstanding common shares of the registrant on April 12, 2017 was 5,447,787.

DOCUMENTS INCORPORATED BY REFERENCE: None

TITAN ENERGY, LLC

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ON FORM 10-K

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GLOSSARY OF TERMS

On August 26, 2016, an order confirming the pre-packaged plan of reorganization (the “Plan”) of our Predecessor and certain of its subsidiaries (collectively with our Predecessor, the “Predecessor Companies”) was entered by the United States Bankruptcy Court for the Southern District of New York.

On September 1, 2016, the Predecessor Companies substantially consummated the Plan and emerged from their Chapter 11 Filings. As part of the transactions undertaken pursuant to the Plan, (i) our Predecessor’s equity was cancelled, (ii) our Predecessor transferred all of its assets and operations to us as a new holding company and (iii) our Predecessor dissolved. As a result, we became the successor issuer to our Predecessor for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”).

Unless the context requires otherwise or unless otherwise noted, all references in this report to:

•“the Company” or “the Successor” refer to Titan Energy, LLC (formerly known as Atlas Resource Finance Corporation) and its subsidiaries;

•our “Predecessor” or “ARP” refer to Atlas Resource Partners, L.P.

•“we,” “our,” “us” or like terms refer, after the consummation of the Plan, to the Company and, prior to the consummation of the Plan, to our Predecessor and the entirety of its business, assets and operations that were contributed to us in connection with the consummation of the Plan;

•our “Board” refer to the board of directors of the Company;

•“Titan Operating” refer to Titan Energy Operating, LLC, our wholly owned subsidiary, through which we hold the assets of our Predecessor;

•“Titan Management” refer to Titan Energy Management, LLC, a wholly owned subsidiary of ATLS; and

•“ATLS” refer to Atlas Energy Group, LLC.

Bbl. One barrel of crude oil, condensate or other liquid hydrocarbons equal to 42 United States gallons.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of gas to one Bbl oil, condensate or natural gas liquids.

Bpd. Barrels per day.

Btu. One British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Common Shares. Our common shares representing limited liability company interests.

condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Drilling Partnerships. Tax-advantaged investment partnerships of which we are a sponsor and manager and in which we co-invest, to finance a portion of our natural gas, crude oil and NGLs production activities.

dry hole or well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

EBITDA. Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is considered to be a non-GAAP measurement.

exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well (as such terms are defined in the federal securities laws).

FASB. Financial Accounting Standards Board.

field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

fractionation. The process used to separate a natural gas liquid stream into its individual components.

GAAP. Generally Accepted Accounting Principles in the United States of America.

gross acres or gross wells. A gross well or gross acre is a well or acre in which the registrant owns a working interest.

LLC Agreement. Our amended and restated limited liability company agreement.

MLP. Master limited partnership.

MBbl. One thousand barrels of crude oil, condensate or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas; the standard unit for measuring volumes of natural gas.

Mcfe. Mcf of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcfd. One thousand cubic feet per day.

Mcfed. One Mcfe per day.

MMBbl. One million barrels of crude oil, condensate or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcfe. One million cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfd. One MMcfe per day.

net acres or net wells. A new well or net acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or net acres is the sum of the fractional working interests owned in gross wells or gross acres expressed as whole numbers and fractions of whole numbers.

natural gas liquids or NGLs —A mixture of light hydrocarbons that exist in the gaseous phase at reservoir conditions but are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus (the main constituent of condensates).

NYMEX. The New York Mercantile Exchange.

NYSE. The New York Stock Exchange.

oil. Crude oil and condensate.

Plan Effective Date. September 1, 2016, the date that we emerged from the Chapter 11 Filings as the Successor.

productive well. A producing well or well that is found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil and gas well.

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proved developed reserves. Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

proved reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

- (i) The area of the reservoir considered as proved includes:
 - (a) The area identified by drilling and limited by fluid contacts, if any, and
 - (b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
- (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
- (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
- (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
 - (a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
 - (b) The project has been approved for development by all necessary parties and entities, including governmental entities.
- (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

proved undeveloped reserves or PUDs. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

PV-10. Present value of future net revenues. See the definition of “standardized measure.”

recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

reserves. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a

known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

SEC. Securities Exchange Commission.

standardized measure. Standardized measure, or standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities, is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses, debt service or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

successful well. A well capable of producing oil and/or gas in commercial quantities.

undeveloped acreage or undeveloped acres. Undeveloped acreage encompasses those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

working interest. An operating interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and the responsibility to pay royalties and a share of the costs of drilling and production operations under the applicable fiscal terms. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100.00% working interest in a lease burdened only by a landowner's royalty of 12.50% would be required to pay 100.00% of the costs of a well but would be entitled to retain 87.50% of the production.

FORWARD-LOOKING STATEMENTS

The matters discussed within this report include forward-looking statements. These statements may be identified by the use of forward-looking terminology such as "anticipate," "believe," "continue," "could," "estimate," "expect," "intend," "might," "plan," "potential," "predict," "should," or "will," or the negative thereof or other variations thereon or comparable terminology. In particular, statements about our expectations, beliefs, plans, objectives, assumptions or future events or performance contained in this report are forward-looking statements. We have based these forward-looking statements on our current expectations, assumptions, estimates and projections. While we believe these expectations, assumptions, estimates and projections are reasonable, such forward-looking statements are only predictions and involve known and unknown risks and uncertainties, many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. Some of the key factors that could cause actual results to differ from our expectations include:

- our ability to achieve the anticipated benefits from the consummation of the Chapter 11 Filings;
- the prices of natural gas, oil, NGLs and condensate;
- changes in the market price of our Common Shares;
- future financial and operating results;

- actions that we may take in connection with our liquidity needs, including the ability to service our debt, and ability to satisfy covenants in our debt documents;
- economic conditions and instability in the financial markets;
- the impact of our securities being quoted on the OTCQX Market rather than listed on a national exchange like the NYSE;
- success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves and meeting our substantial capital investment needs;
- the accuracy of estimated natural gas and oil reserves;
- the financial and accounting impact of hedging transactions;

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- potential changes in tax laws and environmental and other regulations which may affect our operations;
- the ability to obtain adequate water to conduct drilling and production operations, and to dispose of the water used in and generated by these operations at a reasonable cost and within applicable environmental rules;
- the effects of unexpected operational events and drilling conditions, and other risks associated with drilling operations;
- impact fees and severance taxes;
- the effects of intense competition in the natural gas and oil industry;
- general market, labor and economic conditions and uncertainties;
- the ability to retain certain key customers;
- dependence on the gathering and transportation facilities of third parties;
- the availability of drilling rigs, equipment and crews;
- access to sufficient amounts of carbon dioxide for tertiary recovery operations;
- expirations of undeveloped leasehold acreage;
- exposure to financial and other liabilities of the managing general partners of the investment partnerships;
- exposure to new and existing litigation; and
- development of alternative energy resources.

Other factors that could cause actual results to differ from those implied by the forward-looking statements in this report are more fully described under "Risk Factors". Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

PART I

ITEM 1: BUSINESS

Overview

We are a publicly traded (OTCQX: TTEN) Delaware limited liability company and independent developer and producer of natural gas, crude oil and NGLs, with operations in basins across the United States with a focus on the horizontal development of resource potential from the Eagle Ford Shale in South Texas. We are a sponsor and manager of Drilling Partnerships in which we co-invest, to finance a portion of our natural gas, crude oil and natural gas liquids production activities. As discussed further below, we are the Successor to the business and operations of ARP, a Delaware limited partnership organized in 2012.

Titan Management manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of ATLS, which is a publicly traded company (OTCQX).

We believe we have established a strong track record of growing our reserves, production and cash flows through a balanced mix of natural gas, oil and natural gas liquids exploitation and development, sponsorship of our Drilling Partnerships, and the acquisition of oil and gas properties. Our primary business objective is to generate growing yet stable cash flows through the development and acquisition of mature, long-lived natural gas, oil and natural gas liquids properties. As of December 31, 2016, our estimated proved reserves were 970 Bcfe, including the reserves net to our equity interest in our Drilling Partnerships. Of our estimated proved reserves, approximately 90% were proved developed and approximately 72% were natural gas. For the year ended December 31, 2016, our average daily net production was approximately 225.3 MMcfe.

Our operations include three reportable operating segments: gas and oil production, well construction and completion and other partnership management. For financial and other information about our reportable business segments refer to Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 16 to Item 8: Financial Statements and Supplementary Data.

Liquidity, Capital Resources, and Ability to Continue as a Going Concern

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline and remain low in 2016. These lower commodity prices have negatively impacted our revenues, earnings and cash flows. Sustained low commodity prices could have a material and adverse effect on our liquidity position. In addition, challenges with our ability to raise capital through our Drilling Partnerships, either as a result of downturn in commodity prices or other difficulties affecting the fundraising channel, have negatively impacted our ability to remain in compliance with the covenants under our credit facilities.

We are not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. We do not

currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. In addition to the \$30 million of indebtedness due on May 1, 2017, we classified the remaining \$666.8 million of outstanding indebtedness under our credit facilities as a current liability, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. In total, we have \$694.8 million of outstanding indebtedness under our credit facilities, which is net of \$2 million of deferred financing costs, as current portion of long term debt, net within our consolidated balance sheet as of December 31, 2016.

Subject to receiving the remaining First Lien lenders' consent, we expect to finalize an amendment to our First Lien Facility on April 19, 2017 in an attempt to ameliorate some of our liquidity concerns. The amendment is expected to provide for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a "going concern" qualification. The First Lien lenders' waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional

events of default under the First Lien Facility. Further, unless we are able to obtain an amendment or waiver, the lenders under our Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without a going concern qualification. Please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities—Credit Facility Amendment.”

Even following the amendment, we will continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. Please see “Risk Factors—Risks Related to Our Liquidity— Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time, and we are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet.”

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the “Restructuring Support Agreement”) with (i) lenders holding 100% of ARP’s senior secured revolving credit facility (the “First Lien Lenders”), (ii) lenders holding 100% of ARP’s second lien term loan (the “Second Lien Lenders”) and (iii) holders (the “Consenting Noteholders” and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that become party to the Restructuring Support Agreement, the “Restructuring Support Parties”) of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the “7.75% Senior Notes”) and the 9.25% Senior Notes due 2021 (the “9.25% Senior Notes” and, together with the 7.75% Senior Notes, the “Notes”) of ARP’s subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the “Issuers”). Under the Restructuring Support Agreement, the Restructuring Support Parties agreed, subject to certain terms and conditions, to support ARP’s restructuring (the “Restructuring”) pursuant to a pre-packaged plan of reorganization (the “Plan”).

Pursuant to the Restructuring Support Agreement, ARP completed the sale of certain of its commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay \$233.5 million of borrowings outstanding under ARP’s old senior secured revolving credit facility.

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code (“Chapter 11”) in the United States Bankruptcy Court for the Southern District of New York (the “Bankruptcy Court,” and the cases commenced thereby, the “Chapter 11 Filings”). The cases commenced thereby were jointly administered under the caption “In re: ATLAS RESOURCE PARTNERS, L.P., et al.”

ARP operated its businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords were unimpaired by the Plan and were satisfied in full in the ordinary course of business, and ARP’s existing trade contracts and terms were maintained. To assure ordinary course operations, ARP obtained interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to ARP, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the “Plan Effective Date”), pursuant to the Plan, the following occurred:

•the First Lien Lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than \$440 million of principal and face amount of letters of credit) and became lenders under our first lien exit facility credit agreement, composed of a \$410 million conforming reserve-based tranche and a \$30 million non-conforming tranche.

•the Second Lien Lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of \$252.5 million. In addition, the Second Lien Lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.

•Holders of the Notes, in exchange for 100% of the \$668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

•ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended

all of ARP's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

Titan Management, a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights. Four of the seven initial members of the board of directors of us were designated by Titan Management (the "Titan Class A Directors"). For so long as Titan Management holds the Series A Preferred Share, the Class A Directors will be appointed by a majority of the Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

Geographic and Geologic Overview

As of December 31, 2016, our significant gas and oil production positions were in the following six operating areas (refer to Item 2: "Properties" and Item 7: "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information regarding our gas and oil production positions). In connection with our ongoing liquidity enhancement initiatives, we are currently marketing our Appalachia, Raton and Rangely assets to concentrate our portfolio and grow our production through Eagle Ford development in 2017 and 2018.

Eagle Ford. The Eagle Ford Shale is an Upper Cretaceous-age formation that is prospective for horizontal drilling in approximately 26 counties across South Texas. Target vertical depths range from 4,000 to some 11,000+ feet with thickness from 40 to over 400 feet. The Eagle Ford formation is considered to be the primary source rock for many conventional oil and gas fields including the prolific East Texas Oil Field, one of the largest oil fields in the contiguous United States. We own 10,777 contiguous net acres in the Eagle Ford Shale in Atascosa County. We acquired our Eagle Ford position through a series of acquisitions in 2014 and 2015 for approximately \$243 million. During the year, we averaged 9.9 MMcfe/d net production volumes. We estimate 83 Bcfe of total proved reserves for our Eagle Ford position, of which 89% are oil. At December 31, 2016, we had a one-rig program actively drilling on our Eagle Ford Shale position. We anticipate increasing to a two-rig program during the year ended December 31, 2017.

North Texas. Our North Texas position includes the Barnett Shale and Marble Falls play located east of the Bend Arch and west of the Ouachita Thrust in the Fort Worth Basin of northern Texas. The Barnett Shale is Mississippian-age shale formation located at depths between 5,000 and 8,000 feet and ranges in thickness from 100 and 600 feet. The Marble Falls play is a Pennsylvanian-age formation located above the Barnett Shale and beneath the

Atoka at depths of approximately 5,500 feet and ranges in thickness from 50 and 500 feet. We first acquired our positions in the Barnett Shale and Marble Falls play through several acquisitions in 2012, totaling approximately \$653 million, and have continued to build our position through organic drilling. During the year, we averaged 41 MMcfe/d net production volumes. We estimate 115 Bcfe of total proved reserves for our North Texas positions, of which 94% are proved developed and producing (“PDP”).

Appalachian Basin. The Appalachian Basin includes all or parts of: Alabama, Georgia, Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia. It is the most mature natural gas, crude oil and NGL producing region in the United States, having established the first oil production in 1860. Our development and production activities in the Appalachia Basin principally include the Marcellus Shale, Utica-Point Pleasant Shale, Clinton Sand and other conventional formations primarily in Pennsylvania and Ohio. During the year, we averaged 36,406 MMcfe/d net production volumes. We estimate 204 Bcfe of remaining proved reserves for our Appalachian positions, of which 95% are gas.

•The Marcellus Shale is a black, organic rich shale formation located at depths between 4,000 and 8,500 feet and ranges in thickness from 50 to 250 feet. We had an interest in approximately 251 Marcellus Shale wells, consisting of 212 vertical wells and 39 horizontal wells. We have an interest in eight horizontal Marcellus Shale wells in Northeastern Pennsylvania, all of which were developed through our Drilling Partnerships. Approximately 1,558 prospective Marcellus Shale acres remained undeveloped in Lycoming County, Pennsylvania.

•The Utica-Point Pleasant Shale is an Ordovician-age shale, which covers a large portion of Ohio, Pennsylvania, New York and West Virginia and lies several thousand feet below the Devonian-age Marcellus. The Utica-Point Pleasant is an organic rich system comprised of two related shales. The richest concentration of organic material is present within

the Point Pleasant member of the Lower Utica formation; therefore, the primary objective section of this shale play. From central Ohio, the Utica-Point Pleasant play has gentle basin center dip towards its deepest point in central Pennsylvania. In general, as the present day depth increases from West to East, so does the progression of hydrocarbon maturity-along the following, ordered hydrocarbon phase windows: Immature-Oil-Condensate-Rich Gas-Dry Gas Windows. We have an interest in approximately 2,354 wells in Ohio including 12 horizontal Utica-Point Pleasant wells. We have approximately 1,395 net undeveloped acres prospective for the Utica Shale in Trumbull and Stark counties in Ohio.

Coal-Bed Methane. Our coal-bed methane developments are diversified across four well-known coal-bed methane producing areas: the Raton, Black Warrior, Arkoma and Central Appalachian basins. We have more than 476,491 net undeveloped acres prospective for coal-bed methane. We operated 2,783 wells and had an interest in another 910 wells, all of which produce gas generated from coal. During the year, we averaged 116 MMcfe/d net production volumes, representing over 51% of our total production for the year. We estimate 398 Bcfe of remaining proved reserves in our Coal-Bed Methane positions, of which 89% are PDP.

•The Raton asset straddles the New Mexico-Colorado border, along the eastern edge of the Sangre de Cristo Mountains. The production derives from two coal-bearing intervals, the Raton (Tertiary-Upper Cretaceous Age) and Vermajo (Cretaceous Age) formations. The combined net coal thickness ranges between 18 and 65 feet, with depths between 750 and 2,200 feet. We operate 972 wells in our Raton position.

•The Black Warrior coal-bed methane asset is located in central Alabama and geologically related with the frontal thrusts associated with the Appalachian Mountains. The three Pennsylvanian-age coal intervals (Pratt, Mary Lee and Black Creek, listed in increasing stratigraphic depth and age) possess combined net coal thicknesses ranging from 16 to 24 feet, at depths of 500 to 2,400 feet. We operate 858 wells and have an interest in an additional 696 wells in our Black Warrior position. We acquired our Raton and Black Warrior positions through an acquisition in 2013 for approximately \$710 million.

•The Arkoma coal-bed methane asset is located in eastern Oklahoma and the Arkoma basin formed by the Ouachita Mountain uplift to the southeast. The main producing coal is the Hartshorne Coal seam which is of middle Pennsylvanian Age. The net coal thickness ranges from 5 to 10 feet, at depths of 14 to 4,900 feet. We operate 563 wells and have an interest in an additional 66 wells in our Arkoma position. We acquired our Arkoma position through an acquisition in 2015 for approximately \$32 million.

•The Central Appalachian coal-bed methane asset is located in Virginia and West Virginia. The Central Appalachian Basin is a mountainous region where coal mining is prevalent. We operate vertical wells in the Pond Creek and Lasher fields located in southern West Virginia and southwestern Virginia and pinnate horizontal wells in southern and northern West Virginia. We operate 411 wells and have an interest in an additional 72 wells in our Virginia and West Virginia positions. We acquired our Virginia and West Virginia positions through an acquisition in 2014 for approximately \$98 million.

Rangely. The Rangely Oil Field, located in northwestern Colorado, is one of the oldest and largest oil fields in the Rocky Mountain region. We have an approximate 25% non-operating net working interest in the assets and Chevron Corporation is the current owner/operator of the Rangely Weber Sand Unit. The Weber Formation is Permian to Pennsylvanian in age (245-315 million years ago), and typically consists of fine-grained, cross-bedded calcareous sandstones. Average thickness of the unit is 1,200 feet, although the gross reservoir thickness averages 530 feet, and the net production interval within the formation varies from approximately 150 to 250 feet. We acquired our Rangely position through an acquisition in 2014 for approximately \$410 million. Over the past 15 years, the Rangely field has exhibited a 3% exponential annual decline in production. During the year, we averaged 15 MMcfe/d net production

volumes. We estimate 162 Bcfe of total remaining proved reserves in our Rangely position, of which 91% are oil and 81% are PDP.

Mid-Continent. Our Mid-Continent position includes the Mississippi Lime and Hunton formations located in the Anadarko Shelf in northern Oklahoma. The Mississippi Lime formation is an expansive carbonate hydrocarbon system and is located at depths between 4,000 and 7,000 feet between the Pennsylvanian-aged Morrow formation and the Devonian-age world-class source rock Woodford Shale formation. The Mississippi Lime formation can reach 600 feet in gross thickness, with a targeted porosity zone between 50 and 100 feet thickness. The Hunton formation is a limestone formation located at a depth of approximately 7,500 feet, and ranges in thickness from 150 and 300 feet. We acquired our Mississippi Lime position through a series of acquisitions in 2012 for approximately \$60 million. During the year, we averaged 7 MMcfe/d net production volumes. We estimate 123 Bcfe of proved reserves in our Mid-Continent positions, of which 80% are gas. We also own significant salt water disposal assets in the area to support Mississippi Lime production.

Gas and Oil Production

Matters Impacting Comparability of Results

Fresh Start Accounting. Upon our emergence from bankruptcy, we adopted fresh-start accounting in accordance with ASC 852. We qualified for fresh-start accounting because (i) the reorganization value of our assets immediately prior to the confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of existing voting shares of our predecessor company received less than 50% of the voting shares of the post-emergence successor entity.

As a result of the application of fresh start accounting, at the Plan Effective Date, our assets and liabilities were recorded at their estimated fair values which, in some cases, are significantly different than amounts included in our financial statements prior to the Plan Effective Date. Accordingly, our financial condition, results of operations, and cash flows on and after the Effective Date are not comparable to our financial condition, results of operations, and cash flows prior to the Plan Effective Date. References to “Successor” relate to Titan on and subsequent to the Plan Effective Date. References to “Predecessor” refer to ARP prior to the Plan Effective Date. We have presented our financial condition, results of operations, and cash flows with a black line division to delineate the lack of comparability between the amounts presented on or after September 1, 2016 and dates prior.

Production Volumes

Currently, our natural gas, crude oil and NGL production operations are focused in various plays throughout the United States, and include direct interest wells and ownership interests in wells drilled through our Drilling Partnerships. When we drill new wells through our partnership management business we receive an interest in each Drilling Partnership proportionate to the value of our co-investment in it and the value of the acreage we contribute to it, typically 10-30% of the overall capitalization of a particular partnership. The following table presents our total net natural gas, oil and natural gas liquids production volumes and production per day for the periods indicated:

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	Successor Period From	Predecessor Period From		
	September 1, 2016 through December 31, 2016	January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Production per day:				
Natural gas (Mcfed)	183,151	186,962	216,613	238,054
Oil (Bpd)	4,739	4,224	5,139	3,436
Natural gas liquids (Bpd)	2,021	2,296	3,155	3,802
Total (Mcfed)	223,708	226,083	266,374	281,486

Production Revenues, Prices and Costs

Our production revenues and estimated gas, oil and natural gas liquids reserves are substantially dependent on prevailing market prices for natural gas and oil prices. The following table presents our production revenues and average sales prices for our natural gas, oil and natural gas liquids production, along with our average production costs, taxes, and transportation and compression costs for the periods indicated:

	Successor Period From	Predecessor Period From		
	September 1, 2016 through December 31, 2016	January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Production revenues (in thousands): ⁽²⁾				
Natural gas revenue	\$56,670	\$89,223	\$ 217,236	\$ 318,920
Oil revenue	26,088	43,719	122,273	110,070
Natural gas liquids revenue	4,178	6,152	17,490	41,061
Total revenues	\$86,936	\$139,094	\$ 356,999	\$ 470,051
Average sales price:				
Natural gas (per Mcf):				
Total realized price, after hedge ⁽¹⁾⁽²⁾	\$2.63	\$3.34	\$ 3.41	\$ 3.76
Total realized price, before hedge ⁽³⁾	\$2.61	\$1.91	\$ 2.23	\$ 3.93
Oil (per Bbl):				
Total realized price, after hedge ⁽²⁾	\$41.29	\$70.38	\$ 84.30	\$ 87.76

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Total realized price, before hedge	\$45.12	\$36.94	\$ 44.19	\$	82.22
NGLs (per Bbl):					
Total realized price, after hedge ⁽²⁾	\$16.95	\$10.98	\$ 22.40	\$	29.59
Total realized price, before hedge	\$16.95	\$10.98	\$ 12.77	\$	29.39
Production costs (per Mcfe):					
Lease operating expenses ⁽³⁾	\$1.10	\$1.19	\$ 1.34	\$	1.27
Production taxes	0.18	0.19	0.19		0.27
Transportation and compression	0.19	0.23	0.24		0.25
Total	\$1.48	\$1.60	\$ 1.76	\$	1.80

- (1) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effect of this subordination, the average realized gas sales price was \$2.55 per Mcf (\$2.54 per Mcf before the effects of financial hedging), \$3.28 per Mcf (\$1.84 per Mcf before the effects of financial hedging), \$3.36 per Mcf (\$2.19 per Mcf before the effects of financial hedging) and \$3.67 per Mcf (\$3.84 per Mcf before the effects of financial hedging) for the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the Predecessor years ended December 31, 2015 and 2014, respectively.
- (2) Production revenue excludes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015 (see Item 8: “Financial Statements and Supplementary Data – Note 8”). Cash settlements on commodity derivative contracts

excluded from production revenues consisted of \$0.4 million, \$62.6 million and \$48.6 million for natural gas and (\$2.2) million, \$26.4 million and \$35.8 million for oil for the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the Predecessor year ended December 31, 2015, respectively. Cash settlements on natural gas liquids contracts excluded from production revenues consisted of \$8.3 million for the Predecessor year ended December 31, 2015.

(3) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effects of these costs, total lease operating expenses per Mcfe were \$1.07 per Mcfe (\$1.44 per Mcfe for total production costs) and \$1.15 per Mcfe (\$1.57 per Mcfe for total production costs) for the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 and \$1.32 per Mcfe (\$1.74 per Mcfe for total production costs) and \$1.25 per Mcfe (\$1.77 per Mcfe for total production costs) for the Predecessor years ended December 31, 2015 and 2014, respectively.

Partnership Management Business

We conduct certain energy activities through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we will recognize a current liability titled "Liabilities Associated with Drilling Contracts" on our consolidated balance sheet. After the Drilling Partnership well is completed and turned in line, we are entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees we are entitled to receive for services provided, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 10-30%.

During the Successor period from September 1, 2016 through December 31, 2016 we raised \$10.7 million from outside investors for participation in our Drilling Partnerships. During the Predecessor period from January 1, 2012 through August 31, 2016, we raised over \$503.2 million from outside investors for participation in our Drilling Partnerships. Net proceeds from these partnerships are used to fund the investors' share of drilling and completion costs under our drilling contracts with the partnerships.

Our fund raising activities for sponsored Drilling Partnerships during the last five years are summarized in the following table (amounts in millions):

	Drilling Program Capital		
	Investor	Our	Total
	contributions	contributions	capital
Successor period from September 1, 2016 through December 31, 2016	\$10.7	\$ 2.2	\$12.9
Predecessor period from January 1, 2016 through August 31, 2016	—	—	—
Predecessor Year ended December 31, 2015	59.3	17.6	76.9
Predecessor Year ended December 31, 2014	166.8	71.0	237.8
Predecessor Year ended December 31, 2013	150.0	92.3	242.3
Predecessor Year ended December 31, 2012	127.1	54.4	181.5
Total	\$513.9	\$ 237.5	\$751.4

We finance certain of our development drilling activities through the sponsor limited partnerships. Accordingly, the amount of development activities that we will undertake depends in large part upon our ability to obtain investor subscriptions to invest in these Drilling Partnerships. Recently, we have experienced a significant decline in the amount of funds raised. In the future, we may not be successful in raising funds through these Drilling Partnerships at the same levels that we previously experienced, and we also may not be successful in increasing the amount of funds we raise. Our ability to raise funds through our Drilling Partnerships depends in large part upon the perception of investors of their potential return on their investment and their tax benefits from investing in them, which perception is influenced significantly by our historical track record of generating returns and tax benefits to the investors in our existing partnerships. In the event that our Drilling Partnerships do not achieve satisfactory returns on investment or the anticipated tax benefits, we may have difficulty in maintaining or increasing the level of Drilling Partnership fundraising relative to the levels achieved by us. In this event, we may need to seek financing for our drilling activities through alternative methods, which may not be available, or which may be available only on a less attractive basis than the financing we realized through these Drilling Partnerships, or we may determine to reduce drilling activity.

As managing general partner of our Drilling Partnerships, we recognize our Drilling Partnership management fees in the following manner:

- **Well construction and completion.** For each well that is drilled by a Drilling Partnership, we receive a 15% mark-up on those costs incurred to drill and complete the wells included within the partnership. Such fees are earned, in accordance with the partnership agreement, and recognized as the services are performed, typically between 60 and 270 days, using the percentage of completion method;
- **Administration and oversight.** For each well drilled by a Drilling Partnership, we receive a fixed fee between \$100,000 and \$500,000, depending on the type of well drilled, which is earned in accordance with the partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of \$75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed; and
- **Well services.** Each Drilling Partnership pays us a monthly per well operating fee, currently \$1,000 to \$2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed;

Gathering and processing revenue includes gathering fees we charge to the Drilling Partnership wells for our processing plants in the New Albany and the Chattanooga Shales. Generally, we charge a gathering fee to the Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from Drilling Partnerships by approximately 3%.

Our Drilling Partnerships provide tax advantages to our investors because an investor's share of the partnership's intangible drilling cost deduction may be used to offset ordinary income. Intangible drilling costs include items that do not have salvage value, such as labor, fuel, repairs, supplies and hauling. Generally, for our Drilling Partnerships, approximately 80% to 94% of the subscription proceeds received have been used to pay 100% of the partnership's intangible drilling costs. For example, an investment of \$10,000 generally permits the investor to deduct from taxable ordinary income approximately \$8,000 to \$9,400 in the year in which the investor invests.

While our historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

Drilling Activity

The number of wells we drill will vary depending on, among other things, the amount of money we raise through our Drilling Partnerships, the cost of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table sets forth information with respect to the number of wells we drilled, both gross and for our interest, during the periods indicated.

	Successor Period From	Predecessor Period From	
	September 1, 2016 through December 31, 2016	January 1, 2016 through Year Ended August 31, December 31, 2015	Year Ended December 31, 2014
Gross wells drilled ⁽³⁾	—	2 28	129
Net wells drilled ^{(1) (3)}	—	2 17	67
Gross wells turned in line ^{(2) (3)}	15	— 36	119
Net wells turned in line ^{(2) (3)}	6	— 15	64

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage interest in our Drilling Partnerships.

(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.

(3) There were no exploratory wells drilled during any of the periods presented. There were no gross or net dry wells within our operating areas during any of the periods presented.

We do not operate any of the rigs or related equipment used in our drilling operations, relying instead on specialized subcontractors or joint venture partners for all drilling and completion work. This enables us to streamline our operations and conserve capital for investments in new wells, infrastructure and property acquisitions, while generally retaining control over all geological, drilling, engineering and operating decisions. We perform regular inspection, testing and monitoring functions on each of our Drilling Partnerships and our operated wells.

As of December 31, 2016, we did not have any ongoing drilling activities.

Natural Gas and Oil Leases

The typical oil and gas lease agreement provides for the payment of a percentage of the proceeds, known as a royalty, to the mineral owner(s) for all natural gas, oil and other hydrocarbons produced from any well(s) drilled on the leased premises. In the Appalachian Basin and much of the United States, this amount, historically, has ranged between 1/8th (12.5%) and 1/6th (16.66%) of the hydrocarbons produced, resulting in a net revenue interest to us of between 87.5% and 83.33%. With the discovery of the Marcellus and Utica Shales in the Appalachian Basin in the last few years, and the resultant competition for undeveloped acreage, it has become very common for landowners to demand royalty rates up to 20% or higher, resulting in a net revenue interest of 80% or less. In Oklahoma (Mississippi Lime play) and Texas (Barnett and Eagle Ford Shales and Marble Falls play), both states where we have acquired substantial acreage positions, royalties are commonly in the 15-25% range, resulting in net revenue interests to us in the 75-85% range.

In the Texas Barnett and Eagle Ford Shales, Oklahoma Mississippi Lime and Appalachian Basin Marcellus and Utica plays, where horizontal wells are generally drilled on much larger drilling units (sometimes approaching 1,000 acres), the mineral and/or surface rights are generally acquired from multiple parties. In the case of “urban” drilling areas in the Barnett Shale, there may be as many as 3,500 royalty owners within a single drilling unit.

Because the acquisition of hydrocarbon leases in highly desirable basins is an extremely competitive process, and involves certain geological and business risks to identify prospective areas, leases are frequently held by other oil and gas operators. In order to access the rights to drill on those leases held by others, we may elect to farm-in lease rights and/or purchase assignments of leases from competitor operators. Typically, the assignor of such leases will reserve an overriding royalty interest (over and above the existing mineral owner royalty), that can range from 2-3% up to as high as 7 or 8%, and sometimes contain options to convert the overriding royalty interests to working interests at payout of a well. Areas where farm-ins are utilized can result in additional reductions in our net revenue interests, depending upon their terms and how much of a particular drilling unit the farm-in acreage encompasses.

There will be occasions where competitors owning leasehold interests in areas where we want to drill will not farm-out or sell their leases, but will instead join us as working interest partners, paying their proportionate share of all drilling and operating costs in a well. However, it is generally our goal to obtain 100% of the working interest in any and all new wells that we operate.

Contractual Revenue Arrangements

Natural Gas. We market the majority of our natural gas production to gas purchasers directly or to third party midstream companies who gather, treat and process as necessary the gas. The sales price of natural gas produced is a function of the market in the area and typically linked to a regional index. The pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline Zone 4 (200 Leg), Transco Leidy Line, Columbia Appalachia, NYMEX and Texas Eastern Transmission Corporation (TETCO) M2;
- Mississippi Lime - Southern Star;
- Barnett Shale and Marble Falls- primarily Waha but with smaller amounts sold into a variety of north Texas outlets;
- Raton – ANR, Panhandle, and NGPL;
- Black Warrior Basin – Southern Natural;
- Eagle Ford – Houston Ship Channel;

•Arkoma – Enable Gas; and

•Other regions - primarily the Texas Gas Zone SL spot market (New Albany Shale) and the Cheyenne Hub spot market (Niobrara).

We sell the majority of our natural gas at monthly, fixed index first of the month prices and a smaller portion at index daily prices.

We hold firm transportation obligations on Colorado Interstate Gas for the benefit of production from the Raton Basin in the New Mexico/Colorado Area. The total of firm transportation obligations held is approximately 65,000 MMBtu/d under contracts expiring in 2019 and 55,000 MMBtu/d under contracts expiring in 2020. We also hold firm transportation obligations on East Tennessee Natural Gas (25,000 MMBtu/d), Columbia Gas Transmission (14,000 MMBtu/d) and Equitrans (11,000 MMBtu/d) for the benefit of production from the central Appalachian Basin under contracts expiring between the years 2017 and 2024. We hold

gathering obligations with ETC for production in the Barnett Shale. The total gathering obligations held is 2,507 mcf/d under contracts expiring in 2019. We do not have delivery commitments for fixed and determinable quantities of natural gas in any future periods under existing contracts or agreements.

Crude Oil. Crude oil produced from our wells flows directly into leasehold storage tanks where it is sold to an oil purchaser either directly or thru a common carrier acting on behalf of the oil purchaser. The crude oil is typically sold at the prevailing spot market price for each region, less appropriate trucking charges. The majority of our crude oil is sold via truck at the lease. The oil and natural gas liquids production of our Rangely assets flows into a common carrier pipeline and is sold at prevailing market prices, less applicable transportation and oil quality differentials. We do not have delivery commitments or firm transportation obligations for fixed and determinable quantities of crude oil in any future periods under existing contracts or agreements.

Natural Gas Liquids. NGLs are extracted from the natural gas stream by processing and fractionation plants enabling the remaining “dry” gas to meet pipeline specifications for transport or sale to end users or purchasers operating on the receiving pipeline. The resulting plant residue natural gas is sold as described above and the NGLs are generally priced and sold using the Mont Belvieu (TX) or Conway (KS) regional component indices. The cost to process and fractionate the NGLs from the gas stream is typically either a volumetric fee for the gas and liquids processed or a percentage retention by the processing and fractionation facility. We do not have delivery commitments or firm transportation obligations for fixed and determinable quantities of NGLs in any future periods under existing contracts or agreements.

For the Successor period September 1, 2016 through December 31, 2016, Tenaska Marketing Ventures and Chevron within our gas and oil production segment individually accounted for approximately 22% and 15%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the Predecessor period January 1, 2016 through August 31, 2016, Tenaska Marketing Ventures, Chevron and Interconn Resources LLC within our gas and oil production segment individually accounted for approximately 25%, 16% and 13%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity.

Drilling Partnerships. We generally have funded a portion of our drilling activities through sponsorship of tax-advantaged Drilling Partnerships. In addition to providing capital for our drilling activities, our Drilling Partnerships are a source of fee-based revenues, which are not directly dependent on commodity prices. See “Partnership Management Business” for further discussion.

Natural Gas and Oil Hedging

We seek to provide greater stability in our cash flows through our use of financial hedges for our natural gas, oil and natural gas liquids production. The financial hedges may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures and options contracts with qualified counterparties. Financial hedges are contracts between ourselves and counterparties and do not require physical delivery of hydrocarbons. Financial hedges allow us to mitigate hydrocarbon price risk, and cash is settled to the extent there is a price difference between the hedge price and the actual NYMEX settlement price. Settlement typically occurs on a monthly basis, at the time in the future dictated within the hedge contract. Financial hedges executed in accordance with our secured credit facility do not require cash margin and are secured by our natural gas and oil properties. To assure that the financial instruments will be used solely for hedging price risks and not for speculative purposes, we have a management committee to assure that all financial trading is done in compliance with our hedging policies and procedures. We do not intend to contract for positions that we cannot offset with actual production.

Natural Gas Gathering Agreements

Virtually all natural gas produced is gathered through one or more pipeline systems before sale or delivery to a purchaser or an interstate pipeline. A gathering fee can be charged for each gathering activity that is utilized and by each separate gatherer providing the service. Fees will vary depending on the distance the gas travels and whether additional services such as compression, blending, or treating are provided.

Barnett and Marble Falls production in Texas is gathered/processed by a variety of companies depending on the location of the production. As in the case of Appalachian and Mississippi Lime production, either a fee is charged for the gathering activity alone, or a gatherer/processor may provide a combination of services to include processing, fractionation and/or compression. In some instances, the market to which the gas is sold will deduct the third-party gathering fees from the proceeds payable and pay the third-party gatherers directly.

In Appalachia, we have gathering agreements with Laurel Mountain Midstream, LLC (“Laurel Mountain”). Under these agreements, we dedicate our natural gas production in certain areas within southwest Pennsylvania to Laurel Mountain for transportation to interstate pipeline systems or local distribution companies, subject to certain exceptions. In return, Laurel Mountain

is required to accept and transport our dedicated natural gas subject to certain conditions. The greater of \$0.35 per mcf or 16% of the gross sales price of the natural gas is charged by Laurel Mountain for the majority of the gas. A lesser fee does apply to a small number of specific wells in the area. We also use Anadarko Marcellus Midstream, L.L.C.'s facilities to gather our Lycoming Co., Pennsylvania production for a \$0.45 MMBtu fee which delivers our production to Transco Leidy Line pipeline for sale to our purchaser. Our Utica production in Ohio is gathered by both Utica East Ohio Midstream, L.L.C. ("UEO") and Blue Racer Midstream, L.L.C. for delivery to UEO's Kensington Processing plant. Residue gas is sold to purchasers on Dominion East Ohio or Tennessee pipelines. UEO markets the NGLs and returns proceeds to us.

In the Raton Basin (New Mexico and Colorado), we gather all of our production and deliver it to Colorado Interstate Gas Pipeline, an interstate pipeline. In the Black Warrior Basin (Alabama), we gather our own production and deliver it to the Southcross Alabama pipeline who then delivers the gas to the Sothern Natural pipeline to our purchaser.

Mississippi Lime production is currently gathered and processed by SemGas and plant products including gas and NGLs are sold to SemGas. SemGas returns 95 Percent of Proceeds ("POP") of the revenues it receives to Titan from the sale of gas and NGLs. The remaining 5% and a \$0.3276 MMBtu gathering fee are paid to SemGas for all services provided.

Availability of Energy Field Services

We contract for drilling rigs and purchase goods and services necessary for the drilling and completion of wells from a number of drillers and suppliers, none of which supplies a significant portion of our annual needs. Over the past year, we and other oil and natural gas companies have experienced a significant reduction in drilling and operating costs. We cannot predict the duration or stability of the current level of supply and demand for drilling rigs and other goods and services required for our operations with any certainty due to numerous factors affecting the energy industry, including the supply and demand for natural gas and oil.

Competition

The energy industry is intensely competitive in all of its aspects. We operate in a highly competitive environment for acquiring properties and other energy companies, attracting capital for our Drilling Partnerships, contracting for drilling equipment and securing trained personnel. We also compete with the exploration and production divisions of public utility companies for mineral property acquisitions. Competition is intense for the acquisition of leases considered favorable for the development of hydrocarbons in commercial quantities. Our competitors may be able to pay more for hydrocarbon properties and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Furthermore, competition arises not only from numerous domestic and foreign sources of hydrocarbons but also from other industries that supply alternative sources of energy. Product availability and price are the principal means of competition in selling natural gas, crude oil, and natural gas liquids.

Many of our competitors possess greater financial and other resources which may enable them to identify and acquire desirable properties and market their hydrocarbon production more effectively than we do. Moreover, we also compete with a number of other companies that offer interests in Drilling Partnerships. As a result, competition for investment capital to fund Drilling Partnerships is intense.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter

requirements during the summer. This can also lessen seasonal demand fluctuations. In addition, seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in certain areas. These seasonal anomalies may pose challenges for meeting our well construction objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay our operations. We have in the past drilled a greater number of wells during the winter months, because we typically received the majority of funds from Drilling Partnerships during the fourth calendar quarter.

Environmental Matters and Regulation

Our operations relating to drilling and waste disposal are subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As operators within the complex natural gas and oil industry, we must comply with laws and regulations at the federal, state and local levels. These laws and regulations can restrict or affect our business activities in many ways, such as by:

- restricting the way waste disposal is handled;

- limiting or prohibiting drilling, construction and operating activities in sensitive areas such as wetlands, coastal regions, non-attainment areas, tribal lands or areas inhabited by threatened or endangered species;
- requiring the acquisition of various permits before the commencement of drilling;
- requiring the installation of expensive pollution control equipment and water treatment facilities;
- restricting the types, quantities and concentration of various substances that can be released into the environment in connection with siting, drilling, completion, production, and plugging activities;
- requiring remedial measures to reduce, mitigate and/or respond to releases of pollutants or hazardous substances from existing and former operations, such as pit closure and plugging of abandoned wells;
- enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations;
- imposing substantial liabilities for pollution resulting from operations; and
- requiring preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement with respect to operations affecting federal lands or leases.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where pollutants or wastes have been disposed or otherwise released. Neighboring landowners and other third parties can file claims for personal injury or property damage allegedly caused by noise and/or the release of pollutants or wastes into the environment. These laws, rules and regulations may also restrict the rate of natural gas and oil production below the rate that would otherwise be possible. The regulatory burden on the natural gas and oil industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently enact new, and revise existing, environmental laws and regulations, and any new laws or changes to existing laws that result in more stringent and costly waste handling, disposal and clean-up requirements for the natural gas and oil industry could have a significant impact on our operating costs.

We believe that our operations are in substantial compliance with applicable environmental laws and regulations, and compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, we cannot assure future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs.

Environmental laws and regulations that could have a material impact on our operations include the following:

National Environmental Policy Act. Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act, or “NEPA.” NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly affect the environment. In the course of such evaluations, an agency will typically require an Environmental Assessment to assess the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that will be made available for public review and comment. All of our proposed exploration and production activities on federal lands, if any, require governmental permits, many of which are subject to the requirements of NEPA. This process has the potential to delay the development of natural gas and oil projects.

Hydraulic Fracturing. In recent years, federal, state, and local scrutiny of hydraulic fracturing has increased. Regulation of the practice remains largely the province of state governments, except for a Bureau of Land Management rule that would have imposed conditions on fracturing operations on federal lands, which was enjoined

by a federal court holding BLM lacked the authority to adopt the rule. Common elements of state regulations governing hydraulic fracturing may include, but not be limited to, the following: requirement that logs and pressure test results are included in disclosures to state authorities; disclosure of hydraulic fracturing fluids and chemicals, potentially subject to trade secret/confidential proprietary information protections, and the ratios of same used in operations; specific disposal regimens for hydraulic fracturing fluids; replacement/remediation of contaminated water assets; and minimum depth of hydraulic fracturing. In December 2016, EPA released the final report of its study of the impacts of hydraulic fracturing on drinking water in the U.S. finding that the hydraulic fracturing water cycle can impact drinking water resources under some circumstances. Those circumstances included where (1) there are water withdrawals for hydraulic fracturing in times or areas of low water availability, (2) hydraulic fracturing fluids and chemicals or produced water are spilled, (3) hydraulic fracturing fluids are

injected into wells with inadequate mechanical integrity, and (4) hydraulic fracturing wastewater is stored or disposed in unlined pits. If new federal regulations were adopted as a result of these findings, they could increase our cost to operate.

Oil Spills. The Oil Pollution Act of 1990, as amended (“OPA”), contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, the federal regulations that implement the Clean Water Act, and analogous state laws and regulations a number of different types of requirements on our operations. First, these laws and regulations impose restrictions and strict controls on the discharge of pollutants, including produced waters and other natural gas and oil wastes, into navigable waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the relevant state. These permits may require pretreatment of produced waters before discharge. Compliance with such permits and requirements may be costly. Second, the Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The precise definition of waters and wetland subject to the dredge-and-fill permit requirement has been enormously complicated and is subject to on-going litigation. A broader definition could result in more water and wetlands being subject to protection creating the possibility of additional permitting requirements for some of our existing or future facilities. Third, the Clean Water Act also requires specified facilities to maintain and implement spill prevention, control and countermeasure plans and to take measures to minimize the risks of petroleum spills. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for failure to obtain or non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. We believe that our operations are in substantial compliance with the requirements of the Clean Water Act.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended, the federal regulations that implement the Clean Air Act, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including drilling sites, processing plants, certain storage vessels and compressor stations, and also impose various monitoring and reporting requirements. These laws and regulations also apply to entities that use natural gas as fuel, and may increase the costs of customer compliance to the point where demand for natural gas is affected. Clean Air Act rules impose additional emissions control requirements and practices on some of our operations. Some of our new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to comply with new or revised requirements. These regulations may increase the costs of compliance for some facilities. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. We believe that our operations are in substantial compliance with the requirements of the Clean Air Act and comparable state laws and regulations. While we will likely be required to incur certain capital expenditures in the future for air pollution control equipment to comply with applicable regulations and to obtain and maintain operating permits and approvals for air emissions, we believe that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than other similarly situated companies.

Greenhouse Gas Regulation and Climate Change. To date, legislative and regulatory initiatives relating to greenhouse gas emissions have not had a material impact on our business. Under the past eight years during the Obama Administration several Clean Air Act regulations were adopted to reduce greenhouse gas emissions, and a couple foundational regulations were upheld by the courts. President Trump pledged during the election campaign to

suspend or reverse many if not all of the Obama Administration's initiatives to reduce the nation's emissions of greenhouse gases. Some of the foundational regulations, however, appear unyielding. It would be a significant departure from the principle of stare decisis for the Supreme Court to reverse its decision in *Massachusetts v. EPA*, 549 U.S. 497 (2007) holding that greenhouse gases are "air pollutants" covered by the Clean Air Act. Similarly, reversing EPA's final determination that greenhouse gases "endanger" public health and welfare, 74 Fed. Reg. 66,496 (Dec. 15, 2009), upheld in *Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102 (D.C. Cir. 2012), would seem to require development of new scientific evidence that runs counter to general discoveries since that determination.

On March 28, 2017, President Trump issued an Executive Order on Promoting Energy Independence and Economic Growth explaining how his Administration would withdraw, rescind, revisit, or revise virtually every element of the Obama Administration's program for reducing greenhouse gas emissions. Under the Executive Order, some actions had immediate effect. Other actions, including those most directly affecting our operations and the overall consumption of fossil fuels, will be the subject of potentially lengthy notice-and-comment rule-making. With respect to rules more directly applicable to the types of operations we conduct, the Executive Order directed EPA to undertake new rule-making to revise or rescind 2015 methane emissions standards for new or modified wells. Similarly, the Order directed the Department of Interior to re-write a 2015 rule imposing restrictions on fracturing operations conducted on federal land and a 2016 rule restricting flaring of methane emissions from oil and gas extraction on federal

land. With respect to rules of greater applicability affecting overall consumption of fossil fuels, the Order instructed EPA to rewrite (1) the 2015 Clean Power Plan – the rule aimed at reducing greenhouse gas emissions from existing power plants by one-third (compared to 2005 levels), and (2) the 2015 New Source Rule setting greenhouse gas emission requirements for construction of new power plants.

While we generally foresee a less stringent approach to the regulation of greenhouse gases, undoing the Obama Administration’s regulations of greenhouse gas emissions will necessarily involve lengthy notice-and-comment rulemaking and the resulting decisions may then be subject to litigation by those opposed to rolling back existing regulations. Thus, it could be several years before existing regulations are off the books. Opponents of the rollbacks, including states and environmental groups, may then decide to sue large sources of greenhouse gas emissions for the alleged nuisance created by such emissions. In 2011, the Supreme Court held that federal common law nuisance claims were displaced by the EPA’s authority to regulate greenhouse gas emissions from large sources of emissions. If the Administration fails to pursue regulation of emissions from such sources or takes the position that it has no authority to do regulate their emissions, then it is possible that a court would find common law nuisance claims are no longer displaced.

Although further regulation of greenhouse gas emissions from our operations may stall at the federal level, it is possible that, in the absence of additional federal regulatory action, states may pursue additional regulation of our operations, including restrictions on new and existing wells and fracturing operations, as many states already have done.

Waste Handling. The Solid Waste Disposal Act, including RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” and the disposal of non-hazardous wastes. With authority granted by federal EPA, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development and production of crude oil and natural gas constitute “solid wastes,” which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous in the future. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as “solid waste.” The transportation of natural gas in pipelines may also generate some “hazardous wastes” that are subject to RCRA or comparable state law requirements. We believe that our operations are currently in substantial compliance with the requirements of RCRA and related state and local laws and regulations. More stringent regulation of natural gas and oil exploration and production wastes could increase the costs to manage and dispose of such wastes.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the “Superfund” law, imposes joint and several liability, without regard to fault or legality of conduct, on persons who are considered under the statute to be responsible for the release of a “hazardous substance” (but excluding petroleum) into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Our operations are, in many cases, conducted at properties that have been used for natural gas and oil exploitation and production for many years. Although we believe that we utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances may have been released on or under the properties owned or leased by us or on or under other locations, including off-site locations, where such substances have been taken for disposal. We are not presently

aware the need for us to respond to releases of hazardous substances that would impose costs that would be material to our financial condition.

OSHA and Chemical Reporting Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act, or “OSHA,” and comparable state statutes. On March 25, 2016, OSHA published its final Occupational Exposure to Respirable Crystalline Silica final rule, which imposes specific requirements to protect workers engaged in hydraulic fracturing. 81 Fed. Reg. 16,285. The requirements of that final rule as it applies to hydraulic fracturing become effective June 23, 2018, except for the engineering controls component of the final rule, which has a compliance date of June 23, 2021. We expect implementation of the rule to result in significant costs. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA, and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. If the sectors to which community-right-to-know or similar chemical inventory reporting are expanded, our regulatory burden could increase. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans and can result in death. We conduct our natural gas extraction activities in certain formations where hydrogen sulfide may be, or is known to be, present. We employ numerous safety precautions at our operations to ensure the safety of our employees. There are various

federal and state environmental and safety requirements for handling sour gas, and we are in substantial compliance with all such requirements.

Drilling and Production. State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of natural gas and oil properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas, and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our or its wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax or impact fee with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

State Regulation and Taxation of Drilling. The various states regulate the drilling for, and the production, gathering and sale of, natural gas, including imposing severance taxes and requirements for obtaining drilling permits. For example, Pennsylvania has imposed an impact fee on wells drilled into an unconventional formation, which includes the Marcellus Shale. The impact fee, which changes from year to year, is based on the average annual price of natural gas as determined by the NYMEX price, as reported by the Wall Street Journal for the last trading day of each calendar month. For example, based upon natural gas prices for 2015, the impact fee for qualifying unconventional horizontal wells spudded during 2015 was \$45,300 per well, while the impact fee for unconventional vertical wells was \$9,100 per well. The payment structure for the impact fee makes the fee due the year after an unconventional well is spudded, and the fee will continue for 15 years for an unconventional horizontal well and 10 years for an unconventional vertical well. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources.

States may regulate rates of production and may establish maximum limits on daily production allowable from natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from our wells, the type of wells that may be drilled in the future in proximity to existing wells and to limit the number of wells or locations from which we can drill. Texas imposes a 7.5% tax on the market value of natural gas sold, 4.6% on the market value of condensate and oil produced and an oil field clean up regulatory fee of \$0.000667 per Mcf of gas produced, a regulatory tax of \$.001875 and the oil field clean-up fee of \$.00625 per barrel of crude. New Mexico imposes, among other taxes, a severance tax of up to 3.75% of the value of oil and gas produced, a conservation tax of up to 0.24% of the oil and gas sold, and a school emergency tax of up to 3.15% for oil and 4% for gas. Alabama imposes a production tax of up to 2% on oil or gas and a privilege tax of up to 8% on oil or gas. Oklahoma imposes a gross production tax of 7% per Bbl of oil, up to 7% per Mcf of natural gas and a petroleum excise tax of .095% on the gross production of oil and gas.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect upon our unitholders.

Other Regulation of the Natural Gas and Oil Industry. The natural gas and oil industry is extensively regulated by federal, state and local authorities. Legislation affecting the natural gas and oil industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on the industry. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently,

affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in their industries with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the potential costs to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Employees

We do not directly employ any of the persons responsible for our management or operation. In general, personnel employed by ATLS manage and operate our business. As of December 31, 2016, approximately 389 ATLS employees provided direct support to our operations.

Available Information

We make our periodic reports under the Exchange Act, including our annual report on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K, and any amendments to those reports, available through our website at www.titanenergyllc.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. To view these reports, click on “Investor Relations”, then “SEC Filings”. The other information contained on or hyperlinked from our website does not constitute part of this report. You may also receive, without charge, a paper copy of any such filings by request to us at Park Place Corporate Center One, 1000 Commerce Drive, Suite 400, Pittsburgh, Pennsylvania 15275, telephone number (800) 251-0171. A complete list of our filings is available on the SEC’s website at www.sec.gov. Any of our filings are also available at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information.

ITEM 1A: RISK FACTORS

Limited liability company interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider those risk factors included herein, together with all of the other information included in this report, including the matters addressed under “Forward-Looking Statements,” in evaluating an investment in our Common Shares.

If any of the following risks were to occur, our business, financial condition, results of operations and cash flows could be materially adversely affected. In that case, the trading price of our Common Shares could decline and you could lose all or part of your investment.

Risks Related to Our Liquidity

Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time, and we are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet.

We face uncertainty regarding the adequacy of our liquidity and capital resources and have extremely limited, if any, access to additional financing. Pursuant to the expected amendment to our First Lien Facility, the borrowing base will be substantially reduced in the near future. Our cash on hand and cash flow from operations are not sufficient to continue to fund our operations and allow us to satisfy our obligations.

We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, strengthening our balance sheet and meeting our debt service obligations. We could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options, but there is no certainty that we will be able to implement any such options, and we cannot provide any assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. However, there is no guarantee that the proceeds we receive for any asset sale will satisfy the repayment requirements under our First Lien Facility.

We cannot assure you that we would be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that would be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions would allow us to meet our debt obligations and capital requirements.

Please see “Management’s Discussion and Results of Operations— Liquidity, Capital Resources and Ability to Continue as a Going Concern.”

Our substantial indebtedness could adversely affect our financial health and prevent us from fulfilling our debt obligations.

On September 1, 2016, we and Titan Operating, as borrower, entered into the First Lien Credit Facility and the Second Lien Credit Facility, which together currently have approximately \$694.8 million aggregate principal amount of debt outstanding as of December 31, 2016. Our high level of indebtedness could have important consequences for an

investment in us and significant effects on our business. For example, our high level of indebtedness, the funds required to service such debt and the terms of our debt agreements may:

- require a substantial portion of our cash flow to make interest payments on the debt and reduce the cash flow available to fund capital expenditures and to grow our business;
- make it more difficult for us to satisfy our financial obligations under our indebtedness and our contractual and commercial commitments and increase the risk that we may default on our debt obligations;
- increase our vulnerability to downturns in our business, our industry or in the general economy and restrict us from exploiting business opportunities or making acquisitions;

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• limit our flexibility in planning for, or reacting to, changes in our business and the industry;
• place us at a competitive disadvantage relative to our competitors that may not be as leveraged with debt;
• limit our ability to obtain additional financing for working capital, capital expenditures, acquisitions and other investments, or general corporate purposes, which may limit our ability to execute our business strategy;

- limit our ability to refinance our indebtedness on terms that are commercially reasonable, or at all;

• limit management's discretion in operating our business; and

• result in higher interest expense if interest rates increase and we have outstanding floating rate borrowings.

Each of these factors may have a material and adverse effect on our financial condition and viability. Our ability to satisfy our other debt obligations will depend on our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors affecting our company and industry, many of which are beyond our control.

Subject to receiving the remaining First Lien lenders' consent, we expect to finalize an amendment to our First Lien Facility on April 19, 2017 in an attempt to ameliorate some of our liquidity concerns. The amendment is expected to provide for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a "going concern" qualification. The First Lien lenders' waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Facility.

In addition, the expected amendment to our First Lien Credit Facility will result in substantial reductions in our borrowing base in the near future, and we do not currently have sufficient liquidity to make the required repayments. In such event, we may be required to enter into discussions with our First Lien lenders or take other actions, and there can be no guarantee that any such discussions or actions would be successful. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. However, there is no guarantee that the proceeds we receive for any asset sale will satisfy the repayment requirements under our First Lien Facility.

Further, unless we are able to obtain an amendment or waiver, the lenders under our Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without a going concern qualification. However, pursuant to the intercreditor agreement, the lenders under the Second Lien Facility are restricted in their ability to pursue remedies for 180 days from any such notice of default. As of the date hereof, the lenders under the Second Lien Facility have not yet given us notice of any default.

If we cannot make the required payments under our credit facilities, including as a result of a borrowing base redetermination to an amount below our outstanding borrowings, an event of default would result thereunder as well as a cross-default under our other debt agreements. Upon the occurrence of an event of default, the lenders under our credit facilities could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our oil and gas properties and our ownership interests in a majority of the material operating subsidiaries as collateral under our credit facilities. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facilities and our other liabilities.

Our ability to continue as a going concern is dependent upon our ability to sell a significant amount of non-core assets or raise additional capital. As a result, we cannot give any assurance of our ability to continue as a going concern. The report of our independent registered public accounting firm that accompanies the audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern.

Our debt obligations and covenants in our credit facilities restrict our business in many ways and may have a negative impact on our financing options and liquidity position.

Our debt obligations and covenants in our credit facilities could restrict our business in many ways. For example, our First Lien Credit Facility and Second Lien Credit Facility may contain various restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness or grant liens;
- make loans or investments;
- make restricted payments;
- issue preferred stock;
- make distributions from restricted subsidiaries;
- take on debt of unrestricted subsidiaries;
- enter into commodity or interest rate swap arrangements;
- sell assets and subsidiary stock;
- sell all or substantially all of our assets;
- enter into certain transactions with affiliates;
- sell or discount of receivables; and
 - merge into or consolidate with other persons.

In addition, our credit facilities require us to maintain specified financial ratios.

Our ability to meet those financial ratios can be affected by events beyond our control, and we may be unable to meet those tests. If we are unable to meet any of the covenants in our credit facilities, we may be required to enter into discussions with our lenders or take other actions, which may negatively impact the price of our securities.

A breach of any of the covenants in our credit facilities could result in an event of default thereunder as well as a cross-default under our other debt agreements. Upon the occurrence of an event of default, the lenders under our credit facilities could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged substantially all of our assets as collateral under our credit facilities. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facilities and our other liabilities.

In addition, our borrowings under our credit facilities are, and are expected to continue to be, at variable rates of interest and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same.

To the extent that we incur additional indebtedness, the risks described above could increase and the additional debt obligations might subject us to additional and different restrictive covenants that could further affect our financial and operational flexibility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on acceptable terms or at all.

Risks Related to the Chapter 11 Filings

The Chapter 11 Filings may have a negative impact on our image, which may negatively impact our business going forward.

Negative events or publicity associated with our Chapter 11 Filings could adversely affect our relationships with our suppliers, service providers, customers, employees, and other third parties. In addition, we may face greater difficulties in attracting, motivating and retaining management. These and other related issues could adversely affect our operations and financial condition.

Even following the consummation of the Plan, we may not be able to achieve our stated goals and continue as a going concern.

Even following the consummation of the Plan, we continue to face a number of risks, including further deterioration in commodity prices or other changes in economic conditions, changes in our industry, changes in demand for our oil and gas and increasing expenses. Accordingly, we cannot guarantee that the Plan will achieve our stated goals.

Furthermore, even following the reduction in our debts as a result of the consummation of the Plan, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business. Our access to additional financing is, and for the foreseeable future will likely continue to be, extremely limited, if it is available at all.

Our ability to continue as a going concern is dependent upon our ability to raise additional capital. As a result, we cannot give any assurance of our ability to continue as a going concern. The report of our independent registered public accounting firm that accompanies the audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern.

Our financial results may be volatile and may not reflect historical trends.

Following the consummation of the Plan, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities and expenses, contract terminations and rejections, and claims assessments may significantly impact our consolidated financial performance. As a result, our historical financial performance is likely not indicative of our financial performance following the commencement of the Chapter 11 Filings.

In addition, following the consummation of the Plan, the amounts reported in subsequent consolidated financial statements may materially change relative to historical consolidated financial statements, including as a result of revisions to our operating plans pursuant to a plan of reorganization. We adopted fresh-start accounting, in which case our assets and liabilities have been recorded at fair value as of the fresh-start reporting date, which differ materially from the recorded values of assets and liabilities on our Predecessor's consolidated balance sheets. Our financial results after the application of fresh-start accounting also may be different from historical trends.

Risks Relating to Our Business

Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and oil, which have declined substantially. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Continued depressed prices in the future would have a negative impact on our future financial results and could result in an impairment charge. Because our reserves are predominantly natural gas, changes in natural gas prices have a more significant impact on our financial results.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include but are not limited to the following:

- the levels and location of natural gas and oil supply and demand and expectations regarding supply and demand, including the potential long- term impact of an abundance of natural gas and oil (such as that produced from our Marcellus Shale properties) on the domestic and global natural gas and oil supply;
- the level of industrial and consumer product demand;
- weather conditions;
- fluctuating seasonal demand;
- political conditions or hostilities in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level of foreign imports;

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- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall economic conditions, including the value of the U.S. dollar relative to other major currencies.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. In the past, the prices of natural gas, NGLs and oil have been extremely volatile, and we expect this volatility to continue. During the year ended December 31, 2016, the NYMEX Henry Hub natural gas index price ranged from a high of \$3.93 per MMBtu to a low of \$1.64 per MMBtu, and West Texas Intermediate (“WTI”) oil prices ranged from a high of \$54.06 per bbl to a low of \$26.21 per bbl.

A continuation of the prolonged substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition and results of operations. We may use various derivative instruments in connection with anticipated oil and natural gas sales to reduce the impact of commodity price fluctuations. Specifically, the First Lien Credit Facility requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017. However, the entire exposure of our operations from commodity price volatility is not currently hedged, and we may not be able to hedge such exposure going forward. To the extent we do not hedge against commodity price volatility, or our hedges are not effective, our results of operations and financial position may be further diminished.

In addition, low oil and natural gas prices have reduced, and may in the future further reduce, the amount of oil and natural gas that can be produced economically by our operators. This scenario may result in our having to make substantial downward adjustments to our estimated proved reserves, which could negatively impact our borrowing base and our ability to fund our operations. If this occurs or if production estimates change or exploration or development results deteriorate, successful efforts method of accounting principles may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Our operators could also determine during periods of low commodity prices to shut in or curtail production from wells on our properties. In addition, they could determine during periods of low commodity prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices.

Drilling for and producing natural gas and oil are high-risk activities with many uncertainties.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and oil can be uneconomic, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. This risk is exacerbated by the current decline in oil and gas prices. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;
- unexpected operational events and drilling conditions;
- adverse weather conditions;
- facility or equipment malfunctions;

title problems;
pipeline ruptures or spills;
compliance with environmental and other governmental requirements;
unusual or unexpected geological formations;

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- formations with abnormal pressures;
- injury or loss of life and property damage to a well or third-party property;
- leaks or discharges of toxic gases, brine, natural gas, oil, hydraulic fracturing fluid and wastewater from a well;
- environmental accidents, including groundwater contamination;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of natural gas or well fluids.

Any one or more of the factors discussed above could reduce or delay our receipt of drilling and production revenues, thereby reducing our earnings, and could reduce revenues in one or more of our Drilling Partnerships, which may make it more difficult to finance our drilling operations through sponsorship of future partnerships. In addition, any of these events can cause substantial losses, which may not fully be covered by insurance, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties, which could reduce our cash flow.

Although we maintain insurance against various losses and liabilities arising from our operations, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could reduce our results of operations.

We may not be able to continue to raise funds through our Drilling Partnerships at desired levels, which may in turn restrict our ability to maintain our drilling activity at recent levels.

We sponsor limited and general partnerships to finance certain of our development drilling activities. Accordingly, the amount of development activities that we will undertake depends in large part upon our ability to obtain investor subscriptions to invest in these Drilling Partnerships. We raised \$10.7 million, \$59.3 million, \$166.8 million and \$150.0 million in 2016, 2015, 2014, and 2013, respectively. We experienced a significant decline in raising funds in 2016. In the future, we may not be successful in raising any funds through these Drilling Partnerships or at the same levels that we previously experienced, and we also may not be successful in increasing the amount of funds we raise. Our ability to raise funds through our Drilling Partnerships depends in large part upon the perception of investors of their potential return on their investment and their tax benefits from investing in them, which perception is influenced significantly by our historical track record of generating returns and tax benefits to the investors in our existing partnerships. In addition, our fee-based revenues will be based on the number of Drilling Partnerships we sponsor and the number of partnerships and wells we manage or operate. If we are unsuccessful in sponsoring future Drilling Partnerships, our fee-based revenues may decline.

We have agreed to subordinate a portion of our share of production revenues, net of corresponding production costs, to specified returns to the investor partners in the Drilling Partnerships, typically 10% to 12% per year for the first five to eight years of distributions. Thus, our revenues from a particular partnership will decrease if we do not achieve the specified minimum return. In the event that our Drilling Partnerships do not achieve satisfactory returns on investment or the anticipated tax benefits, we may have difficulty in maintaining or increasing the level of Drilling Partnership fundraising relative to the levels achieved by us. In this event, we may need to seek financing for our drilling activities through alternative methods, which may not be available, or which may be available only on a less attractive basis than the financing we realized through these Drilling Partnerships, or we may determine to reduce drilling activity.

Changes in tax laws may impair our ability to obtain capital funds through Drilling Partnerships.

Under current federal tax laws, there are tax benefits to investing in Drilling Partnerships, including deductions for intangible drilling costs and depletion deductions. However, from time to time members of Congress introduce

legislation that would, among other things, eliminate or reduce certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs and certain environmental clean-up costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development. The repeal of these oil and gas tax benefits, if it

happens, would result in a substantial decrease in tax benefits associated with an investment in our Drilling Partnerships. These or other changes to federal tax law may make investment in the Drilling Partnerships less attractive and, thus, reduce our ability to obtain funding from this significant source of capital funds.

Competition in the natural gas and oil industry is intense, which may hinder our ability to acquire natural gas and oil properties and companies and to obtain capital, contract for drilling equipment and secure trained personnel.

We operate in a highly competitive environment for acquiring properties and other natural gas and oil companies, attracting capital through our Drilling Partnerships, contracting for drilling equipment and securing trained personnel. Our competitors may be able to pay more for natural gas, natural gas liquids and oil properties and drilling equipment and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Moreover, our competitors for investment capital may have better track records in their programs, lower costs or stronger relationships with participants in the oil and gas investment community than we do. All of these challenges could make it more difficult for us to execute our growth strategy. We may not be able to compete successfully in the future in acquiring leasehold acreage or prospective reserves or in raising additional capital.

Furthermore, competition arises not only from numerous domestic and foreign sources of natural gas and oil but also from other industries that supply alternative sources of energy. Competition is intense for the acquisition of leases considered favorable for the development of natural gas and oil in commercial quantities. Product availability and price are the principal means of competition in selling natural gas and oil. Many of our competitors possess greater financial and other resources than we do, which may enable them to identify and acquire desirable properties and market their natural gas and oil production more effectively than we can.

Our operations require substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our asset base will decline, which could cause our revenues to decline.

The natural gas and oil industry is capital intensive. If we are unable to obtain sufficient capital funds on satisfactory terms, we may be unable to increase or maintain our inventory of properties and reserve base, or be forced to curtail drilling or other activities. This could cause our revenues to decline and diminish our ability to service any debt that we may have at such time. If we do not make sufficient or effective capital expenditures, including with funds from third-party sources, we will be unable to expand our business operations. In addition, the Chapter 11 Filings have added complexity to our ability to fund capital expenditures.

Economic conditions and instability in the financial markets could negatively impact our business.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the Chinese economy have contributed to economic uncertainty and concerns for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and could lead to a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids produced from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and potential cash available for distribution.

The above factors can also cause volatility in the markets and affect our ability to raise capital and reduce the amount of cash available to fund operations. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. Disruptions in the capital and credit markets could negatively impact our access to liquidity needed for our businesses and impact flexibility to react to changing economic and business conditions. We may be unable to execute our growth strategies, take advantage of business opportunities, respond to competitive pressures or service our debt, any of which could negatively impact our business.

A continuing or weakening of the current economic situation could have an adverse impact on producers, key suppliers or other customers, or on our lenders, causing them to fail to meet their obligations. Market conditions could also impact our derivative instruments. If a counterparty is unable to perform its obligations and the derivative instrument is terminated, our cash flow could be impacted. The uncertainty and volatility surrounding the global financial system may have further impacts on our business and financial condition that we currently cannot predict or anticipate.

Significant physical effects of climate change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate-related damages to our facilities or our costs of operation potentially rising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

We depend on certain key customers for sales of our natural gas, crude oil and natural gas liquids. To the extent these customers reduce the volumes of natural gas, crude oil and natural gas liquids they purchase or process from us, or cease to purchase or process natural gas, crude oil and natural gas liquids from us, our revenues and cash available for distribution could decline.

We market the majority of our natural gas production to gas utility companies, gas marketers, local distribution companies and industrial or other end-users. Crude oil produced from our wells flow directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. NGLs are extracted from the natural gas stream by processing and fractionation plants enabling the remaining “dry” gas (low Btu content) to meet pipeline specifications for transport to end users or marketers operating on the receiving pipeline. For the Successor period September 1, 2016 through December 31, 2016, Tenaska Marketing Ventures and Chevron within our gas and oil production segment individually accounted for approximately 22% and 15%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the Predecessor period January 1, 2016 through August 31, 2016, Tenaska Marketing Ventures, Chevron and Interconn Resources LLC within our gas and oil production segment individually accounted for approximately 25%, 16% and 13%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. To the extent these and other key customers reduce the amount of natural gas, crude oil and natural gas liquids they purchase from us, our revenues and cash flow could temporarily decline in the event we are unable to sell to additional purchasers.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price that we receive for our production could significantly reduce our cash available for distribution and adversely affect our financial condition.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price that we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead price that we receive could significantly reduce our cash flow and adversely affect our financial condition. We use the relevant benchmark price to calculate our hedge positions, and we do not have any commodity derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials, which could adversely affect our results of operations.

Some of our undeveloped leasehold acreage is subject to leases that may expire in the near future.

As of December 31, 2016, leases covering approximately 11,519 of our 730,885 net undeveloped acres, or 1.6%, are scheduled to expire on or before December 31, 2017. An additional 0.1% of our net undeveloped acres are scheduled to expire in 2018. No leases are scheduled to expire in 2019. If we are unable to renew these leases or any leases scheduled for expiration beyond their expiration date, on favorable terms, we will lose the right to develop the acreage that is covered by an expired lease.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would reduce our cash flow from operations and income.

Producing natural gas and oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our natural gas and oil reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves. Our ability to find and acquire additional recoverable reserves to replace current and future production at acceptable costs depends on our ability to generate sufficient cash flow from operations and other sources of capital, principally from the sponsorship of new Drilling Partnerships, all of which are subject to the risks discussed elsewhere in this section.

Decreases in commodity prices could subject our oil and gas properties to a non-cash impairment loss under U.S. generally accepted accounting principles.

U.S. generally accepted accounting principles require oil and gas properties and other long-lived assets to be reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. We test our oil and gas properties on a field-by-field basis, by determining if the historical cost of proved properties less the applicable depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on our economic interests and our plans to continue to produce and develop proved reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. We estimate prices based on current contracts in place at the impairment testing date, adjusted for basis differentials and market related information, including published future prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates.

Prolonged depressed prices of natural gas and oil may cause the carrying value of our oil and gas properties to exceed the expected future cash flows, and a non-cash impairment loss would be required to be recognized in the financial statements for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. For the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, there were no impairments of proved gas and oil properties.

Estimates of reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Underground accumulations of natural gas and oil cannot be measured in an exact way. Natural gas and oil reserve engineering requires subjective estimates of underground accumulations of natural gas and oil and assumptions concerning future natural gas prices, production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Our current estimates of our proved reserves are prepared by our internal engineers and our independent petroleum engineers. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. Some of our reserve estimates were made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, we make certain assumptions regarding future natural gas prices, production levels and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Our standardized measure is calculated using natural gas prices that do not include financial hedges. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves. We base the estimated discounted future net cash flows from our proved reserves on historical prices and costs. However, actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- the amount and timing of our capital expenditures; and
- changes in governmental regulations or taxation.

The timing of both our production and incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Any significant variance in our assumptions could materially affect the quantity and value of reserves, the amount of standardized measure, and our financial condition and results of operations. In addition, our reserves or standardized measure may be

revised downward or upward based upon production history, results of future exploitation and development activities, prevailing natural gas and oil prices and other factors. A material decline in prices paid for our production can reduce the estimated volumes of our reserves because the economic life of our wells could end sooner. Similarly, a decline in market prices for natural gas or oil may reduce our standardized measure.

Hedging transactions may limit our potential gains or cause us to lose money.

Pricing for natural gas, NGLs and oil has been volatile and unpredictable for many years. To limit exposure to changing natural gas and oil prices, we may use financial hedges and physical hedges for our production. Specifically, the First Lien Credit Facility requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017. Physical hedges are not deemed hedges for accounting purposes because they require firm delivery of natural gas and oil and are considered normal sales of natural gas and oil. We generally limit these arrangements to smaller quantities than those we project to be available at any delivery point.

In addition, we may enter into financial hedges, which may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties in compliance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”). The futures contracts are commitments to purchase or sell natural gas and oil at future dates and generally cover one-month periods for up to six years in the future. The over-the-counter derivative contracts are typically cash settled by determining the difference in financial value between the contract price and settlement price and do not require physical delivery of hydrocarbons.

These hedging arrangements may reduce, but will not eliminate, the potential effects of changing commodity prices on our cash flow from operations for the periods covered by these arrangements. Furthermore, while intended to help reduce the effects of volatile commodity prices, such transactions, depending on the hedging instrument used, may limit our potential gains if commodity prices were to rise substantially over the price established by the hedge. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

However, it is not always possible for us to engage in a derivative transaction that completely mitigates our exposure to commodity prices and interest rates. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices and interest rates for which we are unable to enter into a completely effective hedge transaction.

The failure by counterparties to our derivative risk management activities to perform their obligations could have a material adverse effect on our results of operations.

The use of derivative risk management transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. If any of these counterparties were to default on its obligations under our derivative arrangements, such a default could have a material adverse effect on our results of operations, and could result in a larger percentage of our future production being subject to commodity price changes.

Regulations adopted by the Commodities Futures Trading Commission could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The ongoing implementation of derivatives legislation adopted by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The Dodd-Frank Act, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission (the “CFTC”), and the SEC to promulgate rules and regulations implementing the new legislation. The CFTC finalized many of the regulations associated with the reform legislation, and is in the process of implementing position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The CFTC adopted final rules establishing margin requirements for uncleared swaps entered by swap dealers, major swap participants and financial end users (though non-financial end users are excluded from margin requirements). While, as a non-financial end user, we are not subject to margin requirements, application of these requirements to our counterparties could affect the cost and availability of swaps we use for hedging. The financial reform legislation may also require the counterparties to our

derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The new legislation and any new regulations could significantly increase the cost of derivative contracts; materially alter the terms of derivative contracts; reduce the availability of derivatives to protect against risks we encounter; reduce our ability to monetize or restructure our derivative contracts in existence at that time; and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation or regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was also intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and/or cash flows.

Any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
 - the assumption of unknown environmental or title and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns and increased demand on existing personnel;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- the loss of key purchasers of our production; and
- the failure to realize expected growth or profitability.

Our decision to acquire oil and natural gas properties depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations. The scope and cost of the above risks may be materially greater than estimated at the time of the acquisition. Further, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely affect our future growth and the ability to pay distributions.

We may be unsuccessful in integrating the operations from any future acquisitions with our operations and in realizing all of the anticipated benefits of these acquisitions.

The integration of previously independent operations can be a complex, costly and time-consuming process. The difficulties of combining these systems, as well as any operations we may acquire in the future, include, among other things:

- operating a significantly larger combined entity;
- the necessity of coordinating geographically disparate organizations, systems and facilities;

- integrating personnel with diverse business backgrounds and organizational cultures;
- consolidating operational and administrative functions;
- integrating internal controls, compliance under Sarbanes-Oxley Act of 2002 and other corporate governance matters;
- the diversion of management's attention from other business concerns;
- customer or key employee loss from the acquired businesses;

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a significant increase in our indebtedness; and
potential environmental or regulatory liabilities and title problems.

Costs incurred and liabilities assumed in connection with an acquisition and increased capital expenditures and overhead costs incurred to expand our operations could harm our business or future prospects, and result in significant decreases in our gross margin and cash flows.

Our acquisitions may prove to be worth less than we paid, or provide less than anticipated proved reserves, because of uncertainties in evaluating recoverable reserves, well performance, and potential liabilities as well as uncertainties in forecasting oil and natural gas prices and future development, production and marketing costs.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, development potential, well performance, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Our estimates of future reserves and estimates of future production for our acquisitions are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting independent petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain; our proved reserves estimates may thus exceed actual acquired proved reserves. In connection with our assessments, we perform a review of the acquired properties that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of acquired properties are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given the time constraints imposed by the applicable acquisition agreement. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor would it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential.

Any production associated with the assets acquired in the Rangely Acquisition will decline if the operator's access to sufficient amounts of carbon dioxide is limited.

Production associated with the assets we acquired located in the Rangely Field in northwest Colorado (the "Rangely Acquisition") is dependent on CO₂ tertiary recovery operations in the Rangely Field. The crude oil and NGL production from these tertiary recovery operations depends, in large part, on having access to sufficient amounts of CO₂. The ability to produce oil and NGLs from these assets would be hindered if the supply of CO₂ was limited due to, among other things, problems with the Rangely Field's current CO₂ producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Any such supply limitation could have a material adverse effect on the results of operations and cash flows associated with these tertiary recovery operations. Our anticipated future crude oil and NGL production from tertiary operations is also dependent on the timing, volumes and location of CO₂ injections and, in particular, on the operator's ability to increase its combined purchased and produced volumes of CO₂ and inject adequate amounts of CO₂ into the proper formation and area within the Rangely Field.

Ownership of our oil, gas and natural gas liquids production depends on good title to our property.

Good and clear title to our oil and gas properties is important. Although we will generally conduct title reviews before the purchase of most oil, gas, natural gas liquids and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim, which could result in a reduction or elimination of the revenue received by us from such properties.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition and results of operations.

We are subject to comprehensive federal, state, local and other laws and regulations that could increase the cost and alter the manner or feasibility of our doing business.

Our operations are regulated extensively at the federal, state and local levels. The regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas, NGLs and oil we may produce and sell. A major risk inherent in a drilling plan is the need to obtain drilling permits (which can include financial responsibility requirements) from state agencies and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could inhibit our ability to develop our respective properties. The natural gas, NGLs and oil regulatory environment could also change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, reduce our profitability. We may be put at a competitive disadvantage to larger companies in the industry that can spread these additional costs over a greater number of wells and these increased regulatory hurdles over a larger operating staff.

Because we handle natural gas, NGLs and oil, we may incur significant costs and liabilities in the future in order to comply with, or as a result of failing to comply with, new or existing environmental regulations or from an accidental release of substances into the environment.

How we plan, design, drill, install, operate and abandon natural gas and oil wells and associated facilities are matters subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

- The federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;
- The federal Clean Water Act and comparable state laws and regulations that impose obligations related to spills, releases, streams, wetlands and discharges of pollutants into regulated bodies of water;
- The federal Resource Conservation and Recovery Act (“RCRA”) and comparable state laws that impose requirements for the handling and disposal of waste, including produced waters, from our facilities;
- The federal Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”) and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal; and
- Wildlife protection laws and regulations such as the Migratory Bird Treaty Act and the Endangered Species Act, which require operators to cover reserve pits during the cleanup phase of the pit, if the pit is open more than 90 days, and impose restrictions regarding the extent and timing of development, including, for example, prohibitions for tree clearing.

Complying with these environmental requirements may increase costs and prompt delays in natural gas, NGLs and oil production. It is possible that the costs and delays associated with compliance with such requirements could cause us to delay or abandon the further development of certain properties. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.

There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. For example, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and remediation costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies may be enacted or adopted and could significantly increase our compliance costs and the cost of any

remediation that may become necessary. We may not be able to recover remediation costs, or other losses/damages, under our respective insurance policies.

We may incur costs or delays and encounter operational restrictions in connection with complying with stringent environmental regulations that apply specifically to hydraulic fracturing.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand, and chemical additives under pressure into formations to fracture the surrounding rock and stimulate production. Some of the potential effects of Federal, state, and local environmental regulation of hydraulic fracturing, including future changes in such regulation, could include the following:

- additional permitting requirements and permitting delays;
 - increased costs;
 - changes in the way operations, drilling and/or completion must be conducted;
 - increased recordkeeping and reporting; and
 - restrictions on the types of additives that can be used and locations in which we can operate.
- Restrictions on hydraulic fracturing could also reduce the amount of natural gas, NGLs and oil that we are ultimately able to produce from our reserves.

State regulation of hydraulic fracturing and related development operations could result in increased costs and additional operating restrictions or delays.

The hydraulic fracturing and related development operations processes are typically regulated by state oil and natural gas commissions or by state environmental agencies. Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing and related development operations in certain circumstances. State regulation of hydraulic fracturing can take many forms. Among the forms of regulation that do, and in the future could, affect our operations or increase our costs are the following:

- Typically, states impose, by means of permits, well casing, cementing, drilling, mechanical integrity, completion, well control, and plugging and abandonment requirements to ensuring hydraulic fracturing and related development operations do not contaminate groundwater and nearby surface water.
- Most states require the disclosure of chemicals used in hydraulic fracturing fluids.
- Many states have imposed controls on the management, reuse, recycling, and disposal of hydraulic fracturing flowback fluid and production fluids.
- States limit when venting/flaring of casing head gas and gas well gas may occur.
- States may limit where fracturing can be performed and/or impose operating restrictions in certain geographic regions (i.e., location standards). For example, in areas in which there are concerns regarding induced seismicity, a state could curtail fracturing operations in the area or allow its continuance only under certain operational limitations.
- States may impose performance standards for surface activities at oil and natural gas well sites (including containment and spill response and remediation practices) and requiring operators to identify and monitor abandoned, orphaned and inactive wells prior to hydraulic fracturing.
- States may impose conditions on the disposal of drilling wastes containing naturally occurring radioactive material, as well as regulations applying to facilities that receive such wastes.
- States could even take the step of a total ban on hydraulic fracturing, as New York has done, blocking our business from that state.

Local and municipal laws could also result in increased costs and additional operating restrictions or delays.

In addition to state law, local land use restrictions, such as municipal ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing and related operations in particular. In some jurisdictions, the authority of localities to regulate hydraulic fracturing has become contentious. Courts have been

asked to determine whether state regulatory schemes “pre-empt” local regulation. The outcome of legal challenges to local efforts to regulate hydraulic fracturing depends in large part on the intent of the State legislature and the comprehensiveness of its statutory scheme. If the right of municipalities to impose additional requirements is upheld, and municipalities elect to do so, local rules could impose additional constraints – such as siting and setback restrictions – and costs on our operations.

If the federal government were to comprehensively regulate hydraulic fracturing, it could impose greater costs or additional restrictions on our operations.

To date, hydraulic fracturing has not generally been subject to comprehensive regulation at the federal level. Instead, there has been limited federal regulation. For example, U.S. EPA released guidance, under its Safe Drinking Water Act underground injection control authority, regarding the use of diesel fuels in hydraulic fracturing. Implementation of the guidance will largely occur through State permitting programs. As another example, the Department of Interior's Bureau of Land Management had issued regulations governing the conduct of hydraulic fracturing federal and Indian lands, but, on June 21, 2016, a Wyoming federal district judge invalidated the rules on the basis that Congress had not given the Department authority to regulate in this manner. The Federal government appealed the decision to the 10th Circuit Court of Appeals on June 24, 2016, and the litigation is ongoing. On-going federal agency environmental reviews of hydraulic fracturing could, however, result in additional regulation. Or Congress could adopt new laws affecting our operations or directing a federal agency to regulate our operations in new or additional ways. Any such development on the federal level could make it more difficult or costly for us to perform hydraulic fracturing to stimulate production from dense subsurface rock formations.

Our drilling and production operations require both adequate sources of water to facilitate the fracturing process and the disposal of flowback and produced fluids. If we are unable to dispose of the flowback and produced fluids at a reasonable cost and in compliance with applicable environmental rules, our ability to produce gas economically and in commercial quantities could be impaired.

A significant portion of our natural gas, NGLs and oil extraction activities utilize hydraulic fracturing, which results in water that must be treated and disposed of in accordance with applicable regulatory requirements. Environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance. Our ability to collect and dispose of flowback and produced fluids will affect our production, and potential increases in the cost of wastewater treatment, handling, and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of wastewater, drilling fluids and other substances associated with the exploration, development and production of natural gas, NGLs and oil.

Rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

In 2012, USEPA established the NSPS rule for oil and natural gas production, transmission, and distribution, and also made significant revisions to the existing National Emission Standards for Hazardous Air Pollutants ("NESHAP") rules for oil and natural gas production, transmission, and storage facilities. These rules require oil and natural gas production facilities to conduct "green completions" for hydraulic fracturing, which is recovering rather than venting the gas and natural gas liquids that come to the surface during completion of the fracturing process. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. Both the NSPS and NESHAP rules continue to evolve based on new information and changing environmental concerns. President Trump's March 28, 2017, Executive Order on Promoting Energy Independence and Economic Growth ordered federal agencies to revisit federal rules aimed at limiting methane emissions from oil and gas wells. We believe it will be several years before those new rules are fully implemented.

States are also proposing increasingly stringent requirements for air pollution control and permitting for well sites and compressor stations. For example, in January 2016, the Governor of Pennsylvania announced a comprehensive new regulatory strategy for reducing methane emissions from new and existing oil and natural gas operations, including well sites, compressor stations, and pipelines. Implementation of this strategy will result in significant changes to the air permitting and pollution control standards that apply to the oil and gas industry in Pennsylvania. It may also influence air programs in other oil and gas-producing states. Moreover, West Virginia issued General Permit 70-A for natural gas production facilities at the well site in 2013. In response to industry concerns regarding the restrictiveness of the general permit, in November 2015, West Virginia issued General Permit 70-B which provides more flexibility for emission sources located at the well site.

Compliance with new rules regulating air emissions from our operations could result in significant costs, including increased capital expenditures and operating costs, and could affect the results of our business.

Climate change laws and regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the natural gas, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations.

With the issuance, on March 28, 2017, of President Trump's Executive Order on Promoting Energy Independence and Economic Growth, we believe it may take many years for new comprehensive federal policy aimed at greenhouse gas emissions to gel (see "Item 1. Business- Environmental Matters and Regulation - Greenhouse Gas Regulation and Climate Change"). Given the Supreme Court's decision in *Massachusetts v. EPA*, 549 U.S. 497 (2007) (holding that greenhouse gases are "air pollutants" covered by the Clean Air Act) and scientific hurdles to overturning EPA's endangerment finding, we believe the new Administration will have to pursue some form of regulation. Regulations with the most direct impact our operations concern controlling methane emissions from wells. Rules that affect overall consumption of fossil fuels, and the mix of fossil fuels consumed, could also affect the demand for our products. We believe, however, that federal agency implementation of the President's Executive Order is some years away. While Congress has from time to time considered legislation to reduce emissions of greenhouse gases, there has not been significant activity in the form of adopted legislation to reduce greenhouse gas emissions at the federal level in recent years. Reports of greater Congressional activity with respect to greenhouse gas emissions are scarce.

In the absence of comprehensive federal climate change policy, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs that typically require major sources of greenhouse gas emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those greenhouse gases. States may also pursue additional regulation of our operations, including restrictions on methane emissions from new and existing wells and fracturing operations. State and regional initiatives could result in significant costs, including increased capital expenditures and operating costs, affect the demand for our products, and could affect the results of their business.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

If fully implemented, environmental policies the new President supported during his campaign could increase supply in the overall markets for fuels, thereby potentially reducing prices for the Company's output.

During the election campaign, President Trump pledged to implement policies that would reinvigorate coal's use for energy production and ease restrictions on production and transportation of petroleum. If fully implemented, these policies could have the effect of increasing the overall fuel supply, thereby reducing prices for the Company's output. For example, President Trump pledged to reverse the prior Administration's policies that disadvantaged coal as a fuel for energy production. President Trump promised to take several actions to encourage burning coal for energy production and lessen the financial burden of environmental regulations on coal-fired plants' operations. The President pledged to withdraw from the Paris Climate Agreement, withdraw or re-write the Clean Power Plan, withdraw mercury limits on coal plants' air emissions, lift the prior Administration's ban on new coal leases on federal lands and end the review of the program's greenhouse gas impacts, and withdraw the "Waters of the United States" stream protection rule. The new Administration has taken this final action. President Trump also indicated his Administration would open more federal lands for oil and gas production, approve the construction of the Keystone Pipeline to facilitate refining of Alberta oil shale in the U.S., license the Dakota Access Pipeline, and open areas in the Arctic and Atlantic Ocean to drilling. If fully implemented, these policies would increase the overall fuel supply and could have the effect of diminishing demand for the Company's natural gas output. Diminished demand could put

additional downward pressure on the price of the natural gas the Company produces.

Impact fees and severance taxes could materially increase our liabilities.

In an effort to offset budget deficits and fund state programs, many states have imposed impact fees and/or severance taxes on the natural gas industry. In February 2012, the Commonwealth of Pennsylvania enacted an “impact fee” on unconventional natural gas and oil production which includes the Marcellus Shale. The impact fee is based upon the year a well is spudded and varies, like most severance taxes, based upon natural gas prices. As of December 31, 2016, the impact fee for our wells, including the wells in our Drilling Partnerships, was approximately \$0.7 million.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and

regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations.

A cyber incident or a terrorist attacks could result in information theft, data corruption, operational disruption and/or financial loss.

We have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications and services, to operate our businesses, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves, as well as other activities related to our businesses. Strategic targets, such as energy-related assets, may be at greater risk of future cyber or terrorist attacks than other targets in the United States. Deliberate attacks on, or security breaches in our systems or infrastructure, or the systems or infrastructure of third parties or the cloud, could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery, challenges in maintaining our books and records and other operational disruptions and third party liability. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Risks Relating to Our Common Shares

If prices of our Common Shares decline, our shareholders could lose a significant part of their investment.

The market price of our Common Shares could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in securities analysts' recommendations and their estimates of our financial performance;
- the public's reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of natural gas and oil companies;
- fluctuations in natural gas and oil prices;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other natural gas and oil companies;
- variations in the amount of our cash distributions;
- future issuances and sales of our securities; and
- changes in general conditions in the U.S. economy, financial markets or the natural gas and oil industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our Common Shares.

The trading price of our Common Shares may be volatile, with the result that an investor may not be able to sell any shares acquired at a price equal to or greater than the price paid by the investor.

Our Common Shares are quoted on the OTCQX Market under the symbol "TTEN." These markets are relatively unorganized, inter-dealer, over-the-counter markets that provide significantly less liquidity than the NASDAQ or the

NYSE. Although we will use our commercially reasonable efforts to list our Common Shares on the NYSE (or other national securities exchange approved by our Board as soon as practicable after the applicable listing standards are satisfied or have been waived, no assurances can be given that our Common Shares can be listed on the NYSE (or other national securities exchange). In this event, there would be a highly illiquid market for our Common Shares and you may be unable to dispose of your Common Shares at desirable prices or at all.

Sales of our Common Shares may cause our share price to decline.

Sales of substantial amounts of our Common Shares in the public market, or the perception that these sales may occur, could cause the market price of our shares to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional shares. In connection with our actions to address our liquidity concerns, we may sell a substantial number of Common Shares, which would result in significant dilution.

Certain shareholders have significant influence over us and their interests might conflict with or differ from your interests as a shareholder.

Holders of our Predecessor's senior notes, in exchange for their claims to the notes, acquired a significant ownership interest in the Common Shares pursuant to the Plan. Our Second Lien Lenders also received a significant ownership interest in our Common Shares. If such holders were to act as a group, such holders would be in a position to control the outcome of certain actions requiring shareholder approval, including the election of directors, without the approval of other shareholders. This concentration of ownership could also facilitate or hinder a negotiated change of control of the Company and, consequently, have an impact upon the value of the Common Shares.

Provisions in our LLC Agreement limit the rights of our shareholders to elect our directors, which limits their ability to influence us or affect our management.

Pursuant to our LLC Agreement, only our Class B directors are elected by the holders of our Common Shares. Further, we are not required to hold an annual meeting for the election of those Class B directors until 2019. In addition, holders of our Predecessor's senior notes and our Second Lien Lenders designated our Class B directors, and are entitled to nominate Class B directors for election beginning in 2019. Beginning in 2019, only shareholders, or a group of shareholders, who own at least 10% of our outstanding Common Shares may nominate a Class B director for election. Accordingly, holders of Common Shares will have no ability to replace members of the Board prior to 2019 and only limited ability to do so thereafter.

We currently do not intend to pay distributions on our Common Shares, and the First Lien Credit Facility and the Second Lien Credit Facility place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our Common Shares appreciates.

We do not plan to pay distributions on our Common Shares in the foreseeable future. Additionally, the First Lien Credit Facility and the Second Lien Credit Facility place certain restrictions on our ability to pay cash distributions. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your Common Shares at a price greater than you paid for it. There is no guarantee that the price of our Common Shares that will prevail in the market will ever exceed the price at which you purchase Common Shares.

We may issue an unlimited number of additional securities, including securities that are senior to the Common Shares, without shareholder approval, which would dilute shareholders' ownership interests.

Our amended and restated limited liability company agreement (our "LLC Agreement") does not limit the number of additional company securities that we may issue at any time without the approval of our shareholders. In addition, we may issue an unlimited number of securities that are senior to the Common Shares in right of distribution, liquidation and voting, without the approval of our shareholders.

Shareholders may have liability to repay distributions that were wrongfully distributed to them, or other liabilities with respect to ownership of our Common Shares.

Under certain circumstances, shareholders may have to repay amounts wrongfully returned or distributed to them. Under Section 18-607 of the Delaware Limited Liability Company Act (the “Delaware Act”), we may not make a distribution to shareholders if the distribution would cause our liabilities to exceed the fair value of our assets. Under Delaware Act, a shareholder who received an impermissible distribution and who knew at the time of the distribution that it violated Delaware Act will be liable to us for the distribution amount. A purchaser of Common Shares who becomes a member is liable for the obligations of the transferring member to make contributions to the limited liability company that are known to such purchaser of Common Shares at the time it became a member and for unknown obligations if the liabilities could be determined from our LLC Agreement.

Shareholders' liability may not be limited if a court finds that shareholder action constitutes control of our business.

A shareholder who does not participate in the control of the Company's business within the meaning of the Delaware Act and otherwise acts in conformity with the provisions of our LLC Agreement will have liability limited to its share of any undistributed profits and assets under the Delaware Act, subject to possible exceptions. Our company is organized under Delaware law and we conduct business in a number of other states. Limitations on the liability of members for the obligations of a limited liability company have not been clearly established in many jurisdictions. We operate in a manner that we consider reasonable and necessary or appropriate to preserve the limited liability of the shareholders. However, there is no guarantee that the shareholders' liability will be limited.

Risks Relating to Conflicts of Interests

Our management and owners and their respective affiliates may have conflicts of interest, which may permit them to favor their own interests over our shareholders' interests.

Conflicts of interest exist and may arise between our directors, officers, affiliates (including ATLS and Titan Management) and owners (including affiliates of the Class B directors), on the one hand, and us and our public shareholders, on the other hand.

Conflicts may arise as a result of the duties of Titan Management to act for the benefit of its owners, which may conflict with our interests and the interests of our public shareholders. Representatives of Titan Management, which is owned by ATLS, have the ability to appoint a majority of the members of the Board. All of our officers are officers of ATLS, and four of our directors are directors of ATLS. Our directors and officers who are also directors and officers of ATLS or Titan Management have a duty to manage ATLS and Titan Management in a manner that is beneficial to ATLS and its unitholders.

Whenever a conflict arises between us, on the one hand, and any affiliated entities, on the other hand, the Board will resolve that conflict. The Board may, but is not required to, seek the approval of such resolutions or courses of action from the Conflicts Committee of the Board or from the holders of a majority of the outstanding Common Shares. Unless the resolution of a conflict is specifically provided for in our LLC Agreement, the Board or the Conflicts Committee may consider any factors they determine in good faith to consider when resolving a conflict. An independent third party is not required to evaluate the resolution. Consequently, the conflicts of interest discussed above may not be resolved in a manner satisfactory to some or all of our shareholders.

Our LLC Agreement eliminates our directors' and officers' default fiduciary duties to our shareholders and restricts the remedies available to shareholders for actions that might otherwise constitute breaches of fiduciary duty.

Our LLC Agreement contains provisions that eliminate any and all fiduciary duties under applicable law and replaces them with contractual standards and also restricts the remedies available to shareholders for actions taken that, without such elimination of any fiduciary duties, might constitute breaches of fiduciary duty by our directors or officers or their affiliates under applicable law. Our LLC Agreement provides that our directors and officers will not have any liability to us or our shareholders for decisions made in their capacity as officers or directors so long as the directors or officers acted in good faith, meaning that the directors or officers believed the decision was not adverse to our interests. These contractual standards reduce the obligations to which directors or officers would otherwise be held. The directors and officers also will not be liable for monetary damages to us or our shareholders for errors of judgment or for any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such directors or officers acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such person's conduct was unlawful.

In making decisions regarding the resolution of conflicts of interest, it will be presumed that the Board acted in good faith, and in any proceeding brought by or on behalf of any shareholder, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards reduce the obligations to which directors and officers would otherwise be held.

By purchasing our Common Shares, you and the other shareholders are bound by the provisions of our LLC Agreement, including the provisions discussed above.

ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

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ITEM 2: PROPERTIES

Natural Gas, Oil and NGL Reserves

The following tables summarize information regarding our estimated proved natural gas, oil and NGL reserves. Proved reserves are the estimated quantities of crude oil, natural gas, and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. The estimated reserves include reserves attributable to our direct ownership interests in oil and gas properties as well as the reserves attributable to our percentage interests in the oil and gas properties owned by Drilling Partnerships in which we own partnership interests. All of the reserves are located in the United States. We base these estimated proved natural gas, oil and NGL reserves and future net revenues of natural gas, oil and NGL reserves upon reports prepared by independent third-party reserve engineers. We have adjusted these estimates to reflect the settlement of asset retirement obligations on gas and oil properties. Summaries of the reserve reports related to our estimated proved reserves at December 31, 2016 are included as Exhibits 99.2 and 99.3 to this report. In accordance with SEC guidelines, we make the standardized measure estimates of future net cash flows from proved reserves using natural gas, oil and NGL sales prices in effect as of the dates of the estimates which are held constant throughout the life of the properties. Our estimates of proved reserves are calculated on the basis of the unweighted adjusted average of the first-day-of-the-month prices for each of the previous twelve months from the periods indicated, which are listed below along with our average realized prices for the same twelve month period.

	Successor December 31, 2016	Predecessor December 31, 2015
Unadjusted Prices		
Natural gas (per MMBtu)	\$2.48	\$ 2.59
Oil (per Bbl)	\$42.75	\$ 50.28
Natural gas liquids (per Bbl)	\$19.57	\$ 11.02
Average Realized Prices, Before Hedge		
Natural gas (per Mcf) ⁽¹⁾	\$2.61	\$ 2.23
Oil (per Bbl)	\$45.12	\$ 44.19
Natural gas liquids (per Bbl)	\$16.95	\$ 12.77

- (1) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the periods presented. Including the effect of this subordination, the average realized sales price was \$2.07 per Mcf and \$2.19 per Mcf at December 31, 2016 and 2015, before the effects of financial hedging, respectively.

Reserve estimates are imprecise and may change as additional information becomes available. Furthermore, estimates of natural gas, oil and NGL reserves are projections based on engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production and the timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas, oil and NGLs that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

The preparation of our natural gas, oil and NGL reserve estimates was completed in accordance with prescribed internal control procedures by our reserve engineers. For the periods presented, other than for our Rangely assets, Wright and Company, Inc. was retained to prepare a report of proved reserves. The reserve information includes natural gas, oil and NGL reserves which are all located in the United States. The independent reserve engineer's evaluation was based on more than 40 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions and government regulations. For our Rangely assets, Cawley, Gillespie, and Associates, Inc. was retained to prepare a report of proved reserves. The independent reserve engineer's evaluation was based on more than 34 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. Our internal control procedures include verification of input data delivered to our third-party reserve specialist, as well as a multi-functional management review. The preparation of reserve estimates was overseen by our Director of Reservoir Engineering, who is a member of the Society of Petroleum Engineers and has more than 18 years of natural gas and oil industry experience. The reserve estimates were reviewed and approved by our senior engineering staff and management, with final approval by our President.

Results of drilling, testing and production subsequent to the date of the estimate may justify revision of these estimates. Future prices received from the sale of natural gas, oil and NGLs may be different from those estimated by our independent third-party engineers in preparing its reports. The amounts and timing of future operating and development costs may also differ from those used.

Due to these factors, the reserves set forth in the following tables ultimately may not be produced and the proved undeveloped reserves may not be developed within the periods anticipated. The estimated standardized measure values may not be representative of the current or future fair market value of our proved natural gas and oil properties. Standardized measure values are based upon projected cash inflows, which do not provide for changes in natural gas, oil and NGL prices or for the escalation of expenses and capital costs. The meaningfulness of these estimates depends upon the accuracy of the assumptions upon which they were based (see “Item 1A: Risk Factors—Risks Relating to Our Business”).

We evaluate natural gas and oil reserves at constant temperature and pressure. A change in either of these factors can affect the measurement of natural gas and oil reserves. We deduct operating costs, development costs and production-related and ad valorem taxes in arriving at the estimated future cash flows. We base the estimates on operating methods and conditions prevailing as of the dates indicated:

	Successor Proved Reserves at December 31, 2016	Predecessor Proved Reserves at December 31, 2015
Proved reserves:		
Natural gas reserves (MMcf):		
Proved developed reserves	690,894	567,992
Proved undeveloped reserves ⁽¹⁾	3,678	36,586
Total proved reserves of natural gas	694,572	604,578
Oil reserves (MBbl):		
Proved developed reserves	24,936	25,484
Proved undeveloped reserves ⁽¹⁾	14,114	19,320
Total proved reserves of oil	39,050	44,804
NGL reserves (MBbl):		
Proved developed reserves	5,975	6,334
Proved undeveloped reserves ⁽¹⁾	890	1,516
Total proved reserves of NGL	6,865	7,850
Total proved reserves (MMcfe)	970,062	920,504
Standardized measure of discounted future cash flows (in thousands)	\$455,658	\$ 502,769

(1) Our ownership in these reserves is subject to reduction as we generally make capital contributions, which includes leasehold acreage associated with our proved undeveloped reserves, to our Drilling Partnerships in exchange for an equity interest in these partnerships, which is approximately 10-30%, which effectively will reduce our ownership interest in these reserves from 100% to our respective ownership interest as we make these contributions.

Proved developed reserves are those reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well. Proved undeveloped reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells on which a relatively major expenditure is required for recompletion.

Proved Undeveloped Reserves (“PUDS”)

PUD Locations. As of December 31, 2016, we had 40 PUD locations totaling approximately 94 net Bcfe’s of natural gas, oil and NGLs. These PUDS are based on the definition of PUD’s in accordance with the SEC’s rules allowing the use of techniques that have been proven effective through documented evidence, such as actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty.

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Material changes in PUDs. As of January 1, 2016, we had 102 PUD locations totaling approximately 162 net Bcfe's of natural gas, oil, and NGLs. Material changes in PUDS that occurred during the year ended December 31, 2016 were due to the following:

- addition of approximately 12 Bcfe due to our drilling and leasing activity in the Eagle Ford Shale,
- addition of approximately 2 Bcfe due to additional Appalachia Clinton drilling locations identified, offset by
- conversion of approximately 7 Bcfe from PUDs to proved developed reserves, and
- negative revisions of approximately 79 Bcfe in PUDs primarily due to the reduction of our five year drilling plans and unfavorable pricing environment.

Development Costs. Costs incurred related to the development of PUDs were approximately \$16.6 million and \$2.3 million during the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, respectively. As of December 31, 2016, there were no PUDs that had remained undeveloped for five years or more. The proved undeveloped reserves disclosed at December 31, 2016 are included within our five-year development plan and will be developed within five years of the initial disclosure.

Productive Wells

The following table sets forth information regarding productive natural gas and oil wells in which we have a working interest as of December 31, 2016. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of productive wells in which we have an interest, directly or through our ownership interests in Drilling Partnerships and net wells are the sum of our fractional working interests in gross wells, based on the percentage interest we own in the Drilling Partnership that owns the well:

	Number of Productive Wells ⁽¹⁾⁽²⁾	
	Gross	Net
Appalachia:		
Gas wells	8,113	7,028
Oil wells	452	420
Total	8,565	7,448
Coal-bed Methane ⁽³⁾ :		
Gas wells	3,588	2,890
Oil wells	—	—
Total	3,588	2,890
North Texas:		
Gas wells	623	492
Oil wells	57	36
Total	680	528
Mid-Continent:		
Gas wells	289	109
Oil wells	—	—
Total	289	109
Rangely:		
Gas wells	—	—
Oil wells	400	101
Total	400	101
Eagle Ford:		
Gas wells	42	32
Oil wells	—	—
Total	42	32
Total:		
Gas wells	12,613	10,519
Oil wells	951	589
Total	13,564	11,108

(1) Includes our proportionate interest in wells owned by 10 Drilling Partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 684 wells.

(2) There were no exploratory wells drilled in any of our operating areas. There were no gross or net dry wells within any of our operating areas.

(3) Coal-bed methane includes our production located in the Arkoma Basin in Arkansas and Oklahoma, Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the Central Appalachian Basin in

Virginia and West Virginia.

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Developed and Undeveloped Acreage

The following table sets forth information about our developed and undeveloped natural gas and oil acreage as of December 31, 2016. The information in this table includes our proportionate interest in acreage owned by Drilling Partnerships.

	Developed acreage (1)		Undeveloped acreage ⁽²⁾	
	Gross ⁽³⁾	Net ⁽⁴⁾	Gross ⁽³⁾	Net ⁽⁴⁾
West Virginia	148,789	82,318	7,019	3,447
Pennsylvania	152,930	146,759	1,194	1,117
New Mexico	126,246	126,246	445,473	445,473
Ohio ⁽⁵⁾	108,417	106,423	98,563	96,456
Texas	78,527	69,476	35,209	29,056
Alabama	57,080	55,848	3,033	1,495
Colorado	39,778	30,483	20,485	20,485
Indiana	32,046	26,806	35,823	30,519
Oklahoma	128,968	96,408	76,235	36,743
Tennessee	20,119	20,119	42,496	42,296
New York	13,093	12,086	20,564	18,662
Virginia	5,240	4,004	2,237	2,086
Other	2,145	983	3,269	3,053
Total	913,378	777,959	791,600	730,885

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which we own a working interest. The number of gross acres is the total number of acres in which we own a working interest.

(4) Net acres is the sum of the fractional working interests owned in gross acres. For example, a 50% working interest in an acre is one gross acre but is 0.5 net acres.

(5) Includes Utica Shale natural gas and oil rights on approximately 1,396 net acres under new leases taken in Ohio that remain undeveloped.

The leases for our developed acreage generally have terms that extend for the life of the wells, while the leases on our undeveloped acreage have terms that vary from less than one year to five years. There are no concessions for undeveloped acreage as of December 31, 2016. As of December 31, 2016, leases covering approximately 11,519 of our 730,885 net undeveloped acres, or 1.6%, are scheduled to expire on or before December 31, 2017, an additional 0.1% are scheduled to expire in 2018, and no leases are scheduled to expire in 2019.

We believe that we hold good and indefeasible title related to our producing properties, in accordance with standards generally accepted in the industry, subject to exceptions stated in the opinions of counsel employed by us in the various areas in which we conduct our activities. We do not believe that these exceptions detract substantially from our use of any property. As is customary in the industry, we conduct only a perfunctory title examination at the time we acquire a property. Before we commence drilling operations, we conduct an extensive title examination and we perform curative work on defects that we deem significant. We or our predecessors have obtained title examinations

for substantially all of our managed producing properties. No single property represents a material portion of our holdings.

Our properties are subject to royalty, overriding royalty and other outstanding interests customary in the industry. Our properties are also subject to burdens such as liens incident to operating agreements, taxes, development obligations under natural gas and oil leases, farm-out arrangements and other encumbrances, easements and restrictions. We do not believe that any of these burdens will materially interfere with our use of our properties.

ITEM 3: LEGAL PROCEEDINGS

We are a party to various routine legal proceedings arising out of the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations. See “Item 8: Financial Statements and Supplementary Data - Note 11”.

ITEM 4: MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5: MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND
ISSUER PURCHASES OF EQUITY SECURITIES

Market Information, Holders and Distribution Policy

Our Common Shares commenced quotation on the OTCQX Market under the symbol "TTEN" on November 22, 2016. The following table sets forth the intraday high and low prices for the Common Shares during the portions of the most recent fiscal quarter during which our Common Shares commenced quotation on the OTCQX Market. At the close of business on April 12, 2017, the closing price of our Common Shares was \$16.50, and there were 8 holders of record.

	High	Low
November 22, 2016 to December 31, 2016	\$24.25	\$20.00

We do not plan to pay distributions on our Common Shares in the foreseeable future. Additionally, under the First Lien Credit Facility and the Second Lien Credit Facility, we are not permitted to pay dividends with respect to our equity interests, except dividends payable solely in the form of additional shares of our capital stock or certain payments among us, our subsidiaries and ATLS.

For information concerning the issuance of the Series A Preferred Share, see "Item 1: Business—Overview—Consummation of the Plan." For information concerning the common shares authorized for issuance under our management incentive plan, as amended, see "Item 12: Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters – Equity Compensation Plan Information."

ITEM 6: SELECTED FINANCIAL DATA

The following table presents selected historical consolidated financial data for us and our Predecessor, as of and for the periods indicated and should be read in conjunction with “Item 7: Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 8: Financial Statements and Supplementary Data”.

	Successor	Predecessor	Predecessor Years Ended December 31,			
	Period From	From				
	September 1	January 1				
	through	through				
	December 31,	August 31,	2015	2014	2013	2012
	2016	2016	(in thousands, except per unit data)			
Statement of operations data:						
Revenues:						
Gas and oil production	\$86,936	\$139,094	\$356,999	\$470,051	\$273,604	\$92,901
Well construction and completion	2,326	19,157	76,505	173,564	167,883	131,496
Gathering and processing	2,159	3,929	7,431	14,107	15,676	16,267
Administration and oversight	708	1,263	7,812	15,564	12,277	11,810
Well services	3,704	11,226	23,822	24,959	19,492	20,041
Gain (loss) on mark-to-market derivatives	(43,892)	(23,916)	267,223	2,819	—	—
Other, net	247	317	241	590	(14,456)	(4,886)
Total revenues	52,188	151,070	740,033	701,654	474,476	267,629
Costs and expenses:						
Gas and oil production	39,418	86,566	169,653	182,226	100,098	26,624
Well construction and completion	2,023	16,658	66,526	150,925	145,985	114,079
Gathering and processing	3,048	5,893	9,613	15,525	18,012	19,491
Well services	2,036	4,677	9,162	10,007	9,515	9,280
General and administrative	18,496	58,004	65,968	72,349	78,063	69,123
Chevron transaction expense	—	—	—	—	—	7,670
Depreciation, depletion and amortization	23,877	82,331	157,978	239,923	139,783	52,582
Asset impairment	—	—	966,635	573,774	38,014	9,507
Total costs and expenses	88,898	254,129	1,445,535	1,244,729	529,470	308,356
Operating loss	(36,710)	(103,059)	(705,502)	(543,075)	(54,994)	(40,727)
Interest expense	(18,327)	(74,587)	(102,133)	(62,144)	(34,324)	(4,195)

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Gain (loss) on asset sales and disposal	180	(479)	(1,181)	(1,869)	(987)	(6,980)
Gain on early extinguishment of debt	—	26,498	—	—	—	—
Reorganization items, net	(870)	(16,614)	—	—	—	—
Other income (loss)	22,413	(9,189)	—	—	—	—
Loss before income taxes	(33,314)	(177,430)	(808,816)	(607,088)	(90,305)	(51,902)
Income tax expense (benefit)	—	—	—	—	—	—
Net loss	(33,314)	(177,430)	(808,816)	(607,088)	(90,305)	(51,902)
Preferred member / limited partner dividends	—	(4,013)	(16,469)	(19,267)	(11,992)	(3,063)
Net loss attributable to common shareholders and Series A-Preferred member	(33,314)) \$—	\$—	\$—	\$—	\$—
Net loss attributable to common limited partners and the general partner	\$—) \$(181,443)	\$(825,285)	\$(626,355)	\$(102,297)	\$(54,965)
Balance sheet data (at period end):						
Property, plant and equipment, net	\$784,723	\$1,154,866	\$1,191,611	\$2,263,820	\$2,182,770	\$1,302,228
Total assets	881,834	1,300,814	1,699,949	2,784,092	2,396,721	1,496,772
Total debt, including current portion, net ⁽¹⁾⁽²⁾	694,810	1,351,435	1,503,427	1,380,432	930,697	349,245
Total members' deficit/partners' capital (deficit)	(6,941)) (279,711)	(84,628)	947,537	1,133,733	862,006

	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 through August 31, 2016	Predecessor 2015	2014	2013	2012
	(in thousands, except per unit data)					
Cash flow data:						
Net cash provided by operating activities	\$ 33,693	\$ 221,106	\$ 172,804	\$ 202,823	\$ 123,932	\$ 16,486
Net cash used in investing activities	(24,333)	(24,894)	(204,002)	(896,443)	(1,049,606)	(644,278)
Net cash provided by (used in) financing activities	(342)	(182,137)	17,304	707,039	904,314	596,272
Capital expenditures	(24,333)	(24,894)	(127,138)	(212,728)	(263,886)	(127,226)

- (1) In April 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs. The updated accounting guidance requires that debt issuance costs be presented as a direct deduction from the associated debt obligation. See “Item 8: Financial Statements and Supplementary Data – Note 2.”
- (2) The total debt balance for the Predecessor period from January 1, 2016 to August 31, 2016 includes our Predecessor’s liabilities subject to comprise which consists of our Predecessor’s 7.75% and 9.25% Senior Notes, Old Second Lien Credit Facility and associated accrued interest costs. See “Item 8: Financial Statements and Supplementary Data – Note 3.”

ITEM 7: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The discussion and analysis presented below provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with "Item 6: Selected Financial Data" and "Item 8: Financial Statements and Supplemental Data", which contains our consolidated financial statements.

The following discussion may contain forward-looking statements that reflect our plans, estimates and beliefs. Forward-looking statements speak only as of the date the statements were made. The matters discussed in these forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from those made, projected or implied in the forward-looking statements. Factors that could cause or contribute to these differences include those discussed below and in "Item 1A: Risk Factors". We believe the assumptions underlying the consolidated financial statements are reasonable. However, our consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows in the future.

BUSINESS OVERVIEW

We are an independent developer and producer of natural gas, crude oil and natural gas liquids with operations in basins across the United States. We sponsor and manage the Drilling Partnerships, in which we coinvest, to finance a portion of our natural gas, crude oil and NGL production activities. As discussed further below, we are the successor to the business and operations of ARP. Titan Management manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of ATLS, which is a publicly traded company.

In addition to its preferred member interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. ("AGP"), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline and remain low in 2016. These lower commodity prices have negatively impacted our revenues, earnings and cash flows. Sustained low commodity prices could have a material and adverse effect on our liquidity position. In addition, challenges with our ability to raise capital through our Drilling Partnerships, either as a result of downturn in commodity prices or other difficulties affecting the fundraising channel, have negatively impacted our ability to remain in compliance with the covenants under our credit facilities.

We are not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. In addition to the \$30 million of indebtedness due on May 1, 2017, we classified the remaining \$666.8 million of outstanding indebtedness under our credit facilities as a current liability, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. In total, we have \$694.8 million of outstanding indebtedness under our credit facilities, which is net of \$2 million of deferred financing costs, as current portion of long term debt, net within our

consolidated balance sheet as of December 31, 2016.

Subject to receiving the remaining First Lien lenders' consent, we expect to finalize an amendment to our First Lien Facility on April 19, 2017 in an attempt to ameliorate some of our liquidity concerns. The amendment is expected to provide for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a "going concern" qualification. The First Lien lenders' waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Facility. Further, unless we are able to obtain an amendment or waiver, the lenders under our

Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without a going concern qualification. Please see “—Liquidity and Capital Resources—Credit Facilities—Credit Facility Amendment.”

Even following the amendment, we will continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. Please see “Risk Factors—Risks Related to Our Liquidity— Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time, and we are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet.”

RECENT DEVELOPMENTS

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the “Restructuring Support Agreement”) with (i) lenders holding 100% of ARP’s senior secured revolving credit facility (the “First Lien Lenders”), (ii) lenders holding 100% of ARP’s second lien term loan (the “Second Lien Lenders”) and (iii) holders (the “Consenting Noteholders” and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that became party to the Restructuring Support Agreement, the “Restructuring Support Parties”) of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the “7.75% Senior Notes”) and the 9.25% Senior Notes due 2021 (the “9.25% Senior Notes” and, together with the 7.75% Senior Notes, the “Notes”) of ARP’s subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the “Issuers”). Under the Restructuring Support Agreement, the Restructuring Support Parties agreed, subject to certain terms and conditions, to support ARP’s restructuring (the “Restructuring”) pursuant to a pre-packaged plan of reorganization (the “Plan”).

Pursuant to the Restructuring Support Agreement, ARP completed the sale of substantially all its commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay \$233.5 million of borrowings outstanding under ARP’s senior secured revolving credit facility.

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code (“Chapter 11”) in the United States Bankruptcy Court for the Southern District of New York (the “Bankruptcy Court,” and the cases commenced thereby, the “Chapter 11 Filings”). The cases commenced thereby were jointly administered under the caption “In re: ATLAS RESOURCE PARTNERS, L.P., et al.”

ARP operated its businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords were unimpaired by the Plan and were satisfied in full in the ordinary course of business, and ARP’s existing trade contracts and terms were maintained. To assure ordinary course operations, ARP obtained interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to ARP, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the “Plan Effective Date”), pursuant to the Plan, the following occurred:

the First Lien Lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than \$440 million of principal and face amount of letters of credit) and became lenders under our first lien exit facility credit agreement, composed of a \$410 million conforming reserve-based tranche and a \$30 million non-conforming tranche (Refer to the “Credit Facilities” section below for further information regarding terms and provisions).

the Second Lien Lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of \$252.5 million (Refer to the “Credit Facilities” section below for further information regarding terms and provisions). In addition, the Second Lien Lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.

holders of the Notes, in exchange for 100% of the \$668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

• ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended.

• All of ARP's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

• Titan Management a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights. Four of the seven initial members of the board of directors of us were designated by Titan Management (the "Titan Class A Directors"). For so long as Titan Management holds the Series A Preferred Share, the Class A Directors will be appointed by a majority of the Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

Consolidation of Drilling Partnerships

On October 24, 2016, the Board of Directors of our subsidiary, Atlas Resources, LLC, approved our acquisition of properties in exchange for assuming all liabilities in connection with the consolidation of certain of our Drilling Partnerships. These acquisitions had an effective date of October 1, 2016. We recorded \$31.0 million and \$14.7 million of gas and oil properties and asset retirement obligations, respectively, which resulted in a non-cash gain of \$22.4 million after other consolidation and transfer adjustments, in the Successor period from September 1, 2016 through December 31, 2016, which was recorded in other income/(loss) in our consolidated statement of operations.

GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by key trends in natural gas and oil production markets. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

The natural gas, oil and natural gas liquids commodity price markets have suffered significant declines since the fourth quarter of 2014 and have continued to remain low in 2016. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, and our ability to make payments on our debts, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas and oil production from particular wells decrease. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. To the extent we do not have sufficient capital, our ability to drill and acquire more reserves will be negatively impacted. Based on current market conditions, we believe that a reduction in our debt and cash interest obligations is needed to improve our financial position and flexibility and to position us to take advantage of opportunities that may arise out of the current industry downturn.

RESULTS OF OPERATIONS

Matters Impacting Comparability of Results

Fresh Start Accounting. Upon our emergence from bankruptcy, we adopted fresh-start accounting in accordance with ASC 852. We qualified for fresh-start accounting because (i) the reorganization value of our assets immediately prior to the confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of existing voting shares of our predecessor company received less than 50% of the voting shares of the post-emergence successor entity.

As a result of the application of fresh start accounting, at the Plan Effective Date, our assets and liabilities were recorded at their estimated fair values which, in some cases, are significantly different than amounts included in our financial statements prior to the Plan Effective Date. Accordingly, our financial condition, results of operations, and cash flows on and after the Effective Date are not

comparable to our financial condition, results of operations, and cash flows prior to the Plan Effective Date. References to “Successor” relate to Titan on and subsequent to the Plan Effective Date. References to “Predecessor” refer to ARP prior to the Plan Effective Date. We have presented our financial condition, results of operations, and cash flows with a black line division to delineate the lack of comparability between the amounts presented on or after September 1, 2016 and dates prior.

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various plays throughout the United States. Through December 31, 2016, we have established production positions in the following operating areas:

- the Eagle Ford Shale in south Texas, in which we acquired acreage and producing wells in November 2014;
- Coal-bed Methane producing natural gas assets in (1) the Raton Basin in northern New Mexico and the Black Warrior Basin in central Alabama, acquired in 2013; (2) the Central Appalachia Basin in West Virginia and Virginia, acquired in 2014, and; (3) the Arkoma Basin in eastern Oklahoma, acquired in 2015.
- the Rangely field in northwest Colorado, a mature tertiary CO₂ flood with low-decline oil production, where we have a 25% non-operated net working interest position which we acquired on June 30, 2014;
- the Appalachia Basin assets, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region; the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; and the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile;
- the North Texas assets, including Barnett Shale and Marble Falls plays, both in the Fort Worth Basin in northern Texas. The Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil.
- the Mid-Continent assets, including Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area, and the Niobrara Shale assets in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled and the number of wells we turned in line, both gross and for our interest, during the periods indicated:

	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 Year Ended December 31, 2015	2014
Gross wells drilled ⁽³⁾ :			
Appalachia	—	—	4
North Texas	—	3	97
Eagle Ford	—	21	2
Mid-Continent	—	4	26
Total	—	28	129
Net wells drilled ⁽¹⁾⁽³⁾ :			
Appalachia	—	—	1
North Texas	—	2	51
Eagle Ford	—	12	1
Mississippi Lime	—	3	14
Total	—	17	67
Gross wells turned in line ⁽²⁾⁽³⁾ :			
Appalachia	—	4	3
North Texas	—	14	94
Eagle Ford	15	5	—
Mid-Continent	—	13	22
Total	15	36	119
Net wells turned in line ⁽¹⁾⁽²⁾⁽³⁾ :			
Appalachia	—	1	1
North Texas	—	4	53
Eagle Ford	6	4	—
Mid-Continent	—	6	10
Total	6	15	64

(1) Includes (i) our percentage interest in the wells in which we have had a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in the Drilling Partnerships.

(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.

(3) There were no exploratory wells drilled during the periods presented. There were no gross or net dry wells within our operating areas during the periods presented.

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Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes per day in each of our operating areas and total production for each of the periods indicated:

	Successor Period From	Predecessor Period From	Year	Year
	September 1	January 1	Year	Year
	through	through	Ended	Ended
	December 31,	August 31,	December 31,	December 31,
	2016	2016	2015	2014
Production volumes per day: ⁽¹⁾				
Appalachia: ⁽²⁾				
Natural gas (Mcf)	36,654	30,925	34,764	40,975
Oil (Bpd)	275	292	353	406
NGLs (Bpd)	312	307	296	371
Total (Mcf)	40,175	34,522	38,658	45,635
Coal-bed Methane: ⁽²⁾				
Natural gas (Mcf)	112,366	117,491	129,453	132,296
Oil (Bpd)	—	—	—	—
NGLs (Bpd)	—	—	—	—
Total (Mcf)	112,366	117,491	129,453	132,296
North Texas: ⁽²⁾				
Natural gas (Mcf)	30,493	33,696	45,220	57,361
Oil (Bpd)	176	253	564	1,066
NGLs (Bpd)	1,109	1,298	1,992	2,698
Total (Mcf)	38,205	43,002	60,555	79,946
Rangely: ⁽³⁾				
Natural gas (Mcf)	—	—	—	—
Oil (Bpd)	2,210	2,287	2,375	1,252
NGLs (Bpd)	241	244	254	132
Total (Mcf)	14,706	15,187	15,778	8,305
Eagle Ford: ⁽⁴⁾				
Natural gas (Mcf)	531	437	315	175
Oil (Bpd)	1,982	1,212	1,443	286
NGLs (Bpd)	111	91	66	40
Total (Mcf)	13,086	8,257	9,370	2,133
Mid-Continent: ⁽²⁾				
Natural gas (Mcf)	3,106	4,413	6,861	7,248
Oil (Bpd)	97	179	404	427
NGLs (Bpd)	247	356	546	561
Total (Mcf)	5,170	7,624	12,560	13,172
Total production volumes per day:				
Natural gas (Mcf)	183,151	186,962	216,613	238,054
Oil (Bpd)	4,739	4,224	5,139	3,436

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NGLs (Bpd)	2,021	2,296	3,155	3,802
Total (Mcfed)	223,708	226,083	266,374	281,486
Total production: ⁽¹⁾⁽³⁾⁽⁴⁾				
Natural gas (MMcf)	22,344	45,619	79,064	86,890
Oil (MBbls)	578	1,031	1,876	1,254
NGLs (MBbls)	247	560	1,151	1,388
Total (MMcfe)	27,292	55,164	97,226	102,742

(1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling Partnership's proportionate net revenue interest in these wells.

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(2) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; North Texas includes our production located in the Barnett and Marble Falls plays in northern Texas; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and the Niobrara Shale (northeastern Colorado).

(3) Rangely includes production from July 1, 2014, the date of acquisition, through December 31, 2014. Production per day represents production based on the full 365-day year ended December 31, 2014.

(4) Eagle Ford includes production from November 5, 2014, the date of acquisition, through December 31, 2014.

Production per day represents production based on the full 365-day year ended December 31, 2014.

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production, along with our average production costs, which include lease operating expenses, taxes, and transportation costs, for each of the periods indicated:

	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Production revenues (in thousands): ⁽¹⁾				
Appalachia:				
Natural gas revenue	\$ 8,651	\$10,838	\$16,987	\$44,526
Oil revenue	1,572	3,443	8,611	12,657
Natural gas liquids revenue	342	280	557	4,004
Total revenues	\$ 10,565	\$14,561	\$26,155	\$61,187
Coal-bed Methane:				
Natural gas revenue	\$ 38,986	\$66,899	\$158,162	\$197,831
Oil revenue	—	—	—	—
Natural gas liquids revenue	—	—	—	—
Total revenues	\$ 38,986	\$66,899	\$158,162	\$197,831
North Texas:				
Natural gas revenue	\$ 7,796	\$9,680	\$36,682	\$65,562
Oil revenue	957	1,113	4,767	35,772
Natural gas liquids revenue	2,014	2,850	9,740	26,344
Total revenues	\$ 10,767	\$13,643	\$51,189	\$127,678
Rangely ⁽²⁾ :				
Natural gas revenue	\$ —	\$—	\$—	\$—
Oil revenue	12,291	23,815	67,225	38,545
Natural gas liquids revenue	1,016	1,557	3,920	2,991

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Total revenues	\$ 13,307	\$25,372	\$71,145	\$41,536
Eagle Ford ⁽³⁾ :				
Natural gas revenue	\$ 176	\$298	\$456	\$183
Oil revenue	10,742	14,622	36,785	9,052
Natural gas liquids revenue	254	305	364	263
Total revenues	\$ 11,172	\$15,225	\$37,605	\$9,498

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	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Mid-Continent:				
Natural gas revenue	\$ 1,061	\$1,508	\$4,949	\$10,818
Oil revenue	526	726	4,885	14,044
Natural gas liquids revenue	552	1,160	2,909	7,459
Total revenues	\$ 2,139	\$3,394	\$12,743	\$32,321
Total production revenues⁽²⁾⁽³⁾:				
Natural gas revenue	\$ 56,670	\$89,223	\$217,236	\$318,920
Oil revenue	26,088	43,719	122,273	110,070
Natural gas liquids revenue	4,178	6,152	17,490	41,061
Total revenues	\$ 86,936	\$139,094	\$356,999	\$470,051
Average sales price:				
Natural gas (per Mcf):⁽⁴⁾				
Total realized price, after hedge ⁽⁵⁾	\$ 2.63	\$3.34	\$3.41	\$3.76
Total realized price, before hedge	\$ 2.61	\$1.91	\$2.23	\$3.93
Oil (per Bbl):				
Total realized price, after hedge ⁽⁶⁾	\$ 41.29	\$70.38	\$84.30	\$87.76
Total realized price, before hedge	\$ 45.12	\$36.94	\$44.19	\$82.22
Natural gas liquids (per Bbl):				
Total realized price, after hedge ⁽⁵⁾	\$ 16.95	\$10.98	\$22.40	\$29.59
Total realized price, before hedge	\$ 16.95	\$10.98	\$12.77	\$29.39
Production costs (per Mcfe):⁽¹⁾				
Appalachia:				
Lease operating expenses ⁽⁶⁾	\$ 0.60	\$0.72	\$1.01	\$1.08
Production taxes	0.00	0.06	0.06	0.07
Transportation	0.24	0.22	0.26	0.42
	\$ 0.84	\$1.00	\$1.33	\$1.58
Coal-bed Methane:				
Lease operating expenses	\$ 0.96	\$0.98	\$1.06	\$1.05
Production taxes	0.26	0.17	0.20	0.33
Transportation	0.19	0.25	0.32	0.32
	\$ 1.40	\$1.40	\$1.58	\$1.71
North Texas:				
Lease operating expenses	\$ 0.81	\$0.84	\$1.27	\$1.41
Production taxes	0.09	0.18	0.17	0.26
Transportation	0.24	0.24	0.12	0.06
	\$ 1.14	\$1.27	\$1.56	\$1.73
Rangely⁽²⁾:				
Lease operating expenses	\$ 4.28	\$4.33	\$4.37	\$4.29

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Production taxes	0.08	0.59	0.53	0.70
Transportation	0.01	0.01	—	—
	\$ 4.37	\$4.92	\$4.91	\$5.00
Eagle Ford ⁽³⁾ :				
Lease operating expenses	\$ 0.88	\$1.71	\$1.83	\$1.03
Production taxes	0.49	0.43	0.30	0.42
Transportation	0.09	0.13	0.08	0.03
	\$ 1.46	\$2.27	\$2.21	\$1.48

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	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 Year through Ended August December 31, 2015	Year Year Year Year	Year Year Year Year
Mid-Continent:				
Lease operating expenses	\$ 1.80	\$1.60	\$ 1.40	\$ 1.47
Production taxes	0.22	0.07	0.07	0.17
Transportation	0.31	0.30	0.27	0.27
	\$ 2.33	\$1.97	\$ 1.75	\$ 1.91
Total production costs ⁽²⁾⁽³⁾ :				
Lease operating expenses ⁽⁶⁾	\$ 1.10	\$1.19	\$ 1.34	\$ 1.27
Production taxes	0.18	0.19	0.19	0.27
Transportation	0.19	0.23	0.24	0.25
	\$ 1.48	\$1.60	\$ 1.76	\$ 1.80

- (1) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; North Texas includes our production located in the Barnett and Marble Falls plays in northern Texas; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and Niobrara Shale (northeastern Colorado).
- (2) Rangely includes production from July 1, 2014, the date of acquisition, through December 31, 2014. Production per day represents production based on the full 365-day year ended December 31, 2014.
- (3) Eagle Ford includes production from November 5, 2014, the date of acquisition, through December 31, 2014. Production per day represents production based on the full 365-day year ended December 31, 2014.
- (4) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effect of this subordination, the average realized gas sales price was \$2.55 per Mcf (\$2.54 per Mcf before the effects of financial hedging), \$3.28 per Mcf (\$1.84 per Mcf before the effects of financial hedging), \$3.36 per Mcf (\$2.19 per Mcf before the effects of financial hedging) and \$3.67 per Mcf (\$3.84 per Mcf before the effects of financial hedging) for the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the Predecessor years ended December 31, 2015 and 2014, respectively.
- (5) Production revenue excludes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015 (see Item 8: "Financial Statements and Supplementary Data – Note 8"). Cash settlements on commodity derivative contracts excluded from production revenues consisted of \$0.4 million, \$62.6 million and \$48.6 million for natural gas and (\$2.2) million, \$26.4 million and \$35.8 million for oil for the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the Predecessor year ended December 31, 2015, respectively. Cash settlements on natural gas liquids

contracts excluded from production revenues consisted of \$8.3 million for the Predecessor year ended December 31, 2015.

- (6) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effects of these costs, Appalachia lease operating expenses were \$0.42 per Mcfe (\$0.65 per Mcfe for total production costs), \$0.49 per Mcfe (\$0.77 per Mcfe for total production costs), \$0.87 per Mcfe (\$1.19 per Mcfe for total production costs) and \$0.93 per Mcfe (\$1.43 per Mcfe for total production costs) for the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the Predecessor years ended December 31, 2015 and 2014, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were \$1.07 per Mcfe (\$1.44 per Mcfe for total production costs) and \$1.15 per Mcfe (\$1.57 per Mcfe for total production costs) for the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, respectively, and \$1.32 per Mcfe (\$1.74 per Mcfe for total production costs) and \$1.25 per Mcfe (\$1.77 per Mcfe for total production costs) for the Predecessor years ended December 31, 2015 and 2014, respectively.

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	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
(in thousands)				
Gas and oil production revenues	\$ 86,936	\$ 139,094	\$ 356,999	\$ 470,051
Gas and oil production costs	\$ (39,418) \$(86,566)\$ (169,653) \$ (182,226)

Our gas and oil production revenues during each of the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 were lower than the Predecessor year ended December 31, 2015 due to declines in production volumes and commodity prices.

The decrease of \$113.1 million in gas and oil production revenues during the Predecessor year ended December 31, 2015, as compared to the Predecessor year ended December 31, 2014 consisted of a \$76.5 million decrease attributable to our North Texas operations, a \$39.6 million decrease attributable to our Coal-bed Methane operations, a \$39.3 million decrease attributable to our Appalachia operations and a \$19.6 million decrease attributable to our Mid-Continent operations, partially offset by a \$29.6 million increase attributable to our Rangely operations acquired during the Predecessor year ended December 31, 2014, a \$28.1 million increase attributable to our Eagle Ford operations acquired during the Predecessor year ended December 31, 2014 and a \$4.2 million decrease in gas revenues subordinated to the investor partners within our Drilling Partnerships.

Our total production costs during each of the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 were lower than the Predecessor year ended December 31, 2015 primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

The \$12.5 million decrease in gas and oil production expenses for the Predecessor year ended December 31, 2015 as compared to the Predecessor year ended December 31, 2014 primarily consisted of a \$16.1 million decrease attributable to our North Texas operations, a \$7.9 million decrease attributable to our Coal-bed Methane operations, a \$7.5 million decrease attributable to our Appalachia operations, and a \$1.1 million decrease attributable to our Mid-Continent operations, partially offset by a \$13.1 million increase attributable to our Rangely operations acquired during the Predecessor year ended December 31, 2014, a \$6.4 million increase attributable to our Eagle Ford operations acquired during the Predecessor year ended December 31, 2014, and a \$0.6 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships.

DRILLING PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling Partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for Drilling Partnerships we sponsor. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill. The following table presents the amounts of Drilling Partnership investor capital raised and deployed, as well as sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Successor Period From September 1 through December 31, 2016	Predecessor Period From January Year through August 31, 2016	2015	Year Ended December 31, 2014
Drilling partnership investor capital:				
Raised	\$ 10,656	\$—	\$ 59,277	\$ 166,798
Deployed	\$ 2,326	\$ 19,157	\$ 76,505	\$ 173,564
Average construction and completion:				
Revenue per well	\$ 1,087	\$ 5,252	\$ 4,286	\$ 2,227
Cost per well	945	4,567	3,727	1,937
Gross profit per well	\$ 142	\$ 685	\$ 559	\$ 290
Gross profit margin	\$ 303	\$ 2,499	\$ 9,979	\$ 22,639
Partnership net wells associated with revenue recognized ⁽¹⁾ :				
Appalachia	—	—	2	3
North Texas	—	—	5	60
Eagle Ford	1	4	6	1
Mid-Continent	—	—	5	14
Total	1	4	18	78

(1) Consists of Drilling Partnership net wells for which well construction and completion revenue was recognized on a cost plus basis.

Our well construction and completion gross profit margin during each of the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 decreased from the Predecessor year ended December 31, 2015 due to the decrease in the number of partnership wells for which completion activities were being performed related to timing and the economics of such activities during the challenging commodity price environment along with a downward revision to our estimated total costs to complete wells, which resulted in unfavorable adjustments to our gross profit margin recognized on our “cost plus” basis for the wells in progress.

The \$12.6 million decrease in well construction and completion gross profit margin for the Predecessor year ended December 31, 2015 as compared to the Predecessor year ended December 31, 2014 consisted of a \$17.4 million decrease related to fewer wells recognized for revenue within our Drilling Partnerships, partially offset by a \$4.8 million increase associated with our higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Eagle Ford Shale wells within our Drilling Partnerships during the Predecessor year ended December 31, 2015 compared with the prior year. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill.

At December 31, 2016, our consolidated balance sheet includes \$10.7 million of “liabilities associated with well drilling contracts” for funds raised by our Drilling Partnerships that have not been applied to the completion of wells due to the timing of drilling operations, and thus had not been recognized as well construction and completion revenue on our consolidated statement of operations. We expect to recognize this amount as revenue during 2017.

Administration and Oversight

	Successor Period From	Predecessor Period From		
	September 1	January	Year	Year
	through	through	Ended	Ended
	December 31,	August 31,	December 31,	December 31,
	2016	2016	2015	2014
(in thousands)				
Administration and oversight revenues	\$ 708	\$ 1,263	\$ 7,812	\$ 15,564

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our Drilling Partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the Drilling Partnerships, such as those in our North Texas Marble Falls play, as compared to deep, horizontal wells, such as those drilled in our Appalachian Marcellus and Utica Shales. The following table presents the number of gross and net development wells we drilled for our Drilling Partnerships during the periods indicated. There were no exploratory wells drilled during the periods indicated:

	Successor Period From	Predecessor Period From		
	September 1	January	Year	Year
	through	through	Ended	Ended
	December 31, 2016	August 31, December 31,	December 31,	December 31,
		2016	2015	2014
Gross partnership wells drilled:				
Appalachia	—	—	—	4
North Texas	—	—	2	77
Eagle Ford	—	2	10	2
Mid-Continent	—	—	2	17

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Total	—	2	14	100
Net partnership wells drilled:				
Appalachia			—	4
North Texas	—	—	2	64
Eagle Ford	—	2	9	1
Mid-Continent	—	—	1	16
Total	—	2	12	85

Our administration and oversight fee revenues during each of the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 decreased from the Predecessor year ended December 31, 2015 primarily due to more wells being spud in the Predecessor year ended December 31, 2015.

The \$7.8 million decrease in administrative and oversight fee revenues for the Predecessor year ended December 31, 2015, compared to the Predecessor year ended December 31, 2014 was due to a decrease in the number of wells spud within the current year period compared with the prior year period, particularly within the North Texas and Mid-Continent areas.

Well Services

	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 Year through August 31, 2016	2015	Year Ended December 31, 2014
(in thousands)				
Well services revenues	\$ 3,704	\$11,226	\$ 23,822	24,959
Well services expenses	\$ (2,036)	\$(4,677)	\$(9,162)	(10,007)

Well service revenue and expenses represent the monthly operating fees we charge and the work our service company performs, including work performed for our Drilling Partnership wells during the drilling and completing phase as well as ongoing maintenance of these wells and other wells for which we serve as operator.

Our well services revenue during each of the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 decreased from the Predecessor year ended December 31, 2015 primarily due to lower fee revenues associated with our salt water gathering and disposal systems within the Mid-Continent and North Texas operating areas, which are utilized by our Drilling Partnership wells, and decreases in revenues due to the number of wells having been shut in and certain Drilling Partnerships consolidated in the current year, both of which result in a reduction of the monthly operating fees we charge the Drilling Partnerships.

Our well services expense during each of the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 decreased from the Predecessor year ended December 31, 2015 primarily due to lower labor costs and related vehicle costs.

The \$1.2 million decrease in well services revenues for the Predecessor year ended December 31, 2015, as compared to the Predecessor year ended December 31, 2014 primarily related to our continued efforts to increase production through intermittent operation of certain legacy wells which results in a reduction of the monthly operating fees which we charge, partially offset by the increased utilization of our salt water gathering and disposal systems within the North Texas and Mid-Continent operating areas by our Drilling Partnership wells.

The \$0.8 million decrease in well services expenses for the Predecessor year ended December 31, 2015, as compared to the Predecessor year ended December 31, 2014 primarily related to lower labor and other employee costs.

Gathering and Processing

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	Successor	Predecessor		
	Period From	Period From		
	September 1	January 1	Year	Year
	through	through	Ended	Ended
	December 31,	August 31	December 31,	December 31,
	2016	2016	2015	2014
(in thousands)				
Gas gathering margin	\$ (889)	\$(1,964)	\$ (2,182)	(1,418)

Gathering and processing margin includes gathering fees we charge to our Drilling Partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale, which are both in our Appalachia operating area. Generally, we charge a gathering fee to our Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

Our gas gathering margin during each of the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 decreased from the Predecessor year ended December 31, 2015

primarily due to lower overall natural gas prices in Appalachia and lower gathering fees, particularly from our Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline, and from certain Drilling Partnerships that were consolidated in the current year.

The \$0.8 million unfavorable movement in gathering and processing margin for the Predecessor year ended December 31, 2015 as compared to the Predecessor year ended December 31, 2014 was principally due to lower gathering fees from our Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline, in comparison with the prior year.

OTHER REVENUES AND EXPENSES

	Successor Period From	Predecessor Period From	Year Ended	Year Ended
	September 1 through	January 1 through August 31,	Year Ended December 31,	December 31,
	2016	2016	2015	2014
(in thousands)				
Other Revenues				
Gain (loss) on mark-to-market derivatives	\$ (43,892)	\$ (23,916)	\$ 267,223	\$ 2,819
Other, net	247	317	241	590
Other Expenses				
General and administrative	\$ 18,496	\$ 58,004	\$ 65,968	\$ 72,349
Depreciation, depletion and amortization	23,877	82,331	157,978	239,923
Asset impairment	—	—	966,635	573,774
Interest expense	18,327	74,587	102,133	62,144
Gain (loss) on asset sales and disposal	180	(479)	(1,181)	(1,869)
Gain on extinguishment of debt	—	26,498	—	—
Reorganization items, net	870	16,614	—	—
Other income (loss)	22,413	(9,189)	—	—
Income tax expense (benefit)	—	—	—	—

Gain (Loss) on Mark-to-Market Derivatives. We recognize changes in the fair value of our derivatives immediately within gain (loss) on mark-to-market derivatives on our consolidated statements of operations. The losses on mark-to-market derivatives during the Successor period from September 1, 2016 through December 31, 2016 and during the Predecessor period from January 1, 2016 through August 31, 2016 were due to an increase in commodity future prices relative to our and our Predecessor's derivative positions. The gain on mark-to-market derivatives during the Predecessor year ended December 31, 2015 was due to our Predecessor discontinuing hedge accounting for its qualified commodity derivatives as of January 1, 2015 and a decrease in commodity futures prices relative to our Predecessor's derivative positions.

On January 1, 2015, our Predecessor discontinued hedge accounting for its qualified commodity derivatives. As such, subsequent changes in fair value of these derivatives were recognized immediately within gain (loss) on mark-to-market derivatives on its consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners' capital (deficit) on our Predecessor's consolidated balance sheet, were reclassified into our consolidated statements of operations at the time the originally hedged physical transactions settled. The \$264.4 million increase in gains on mark-to-market derivatives for the Predecessor year ended December 31, 2015 as compared to the Predecessor year ended December 31, 2014 was due to the change in accounting for its commodity derivatives.

General and Administrative. The Predecessor period from January 1, 2016 through August 31, 2016 included a \$10.9 million provision for losses on receivables from certain Drilling Partnerships to reduce them to their estimated net realizable values and a \$1.6 million valuation adjustment of our Predecessor's subsidiary's deferred tax assets. General and administrative expenses during the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 reflect increases in salaries, wages and benefits and an increase in syndication expenses due to lower investment partnership program fundraising activities, partially offset by decreases in non-cash stock compensation, non-recurring transaction costs and other corporate activities.

The \$6.4 million decrease in general and administrative expenses for the Predecessor year ended December 31, 2015 compared with the Predecessor year ended December 31, 2014 was primarily due to an \$8.8 million decrease in non-recurring transaction costs

related to the acquisitions of assets and a \$3.1 million decrease in non-cash stock compensation, partially offset by a \$5.3 million increase in syndication expenses due to lower investment partnership program fundraising activities.

Depreciation, Depletion and Amortization. The Predecessor period from January 1, 2016 through August 31, 2016 included \$4.2 million of accelerated amortization related to seismic costs. Depreciation, depletion and amortization during the Successor period from September 1, 2016 through December 31, 2016 and during the Predecessor period from January 1, 2016 through August 31, 2016 generally decreased as a result of overall decreases in depletion expense, partially offset by increases in accretion expense. The \$81.9 million decrease in depreciation, depletion and amortization for the Predecessor year ended December 31, 2015 compared with the Predecessor year ended December 31, 2014 was primarily due to an \$84.9 million decrease in our depletion expense, partially offset by a \$0.6 million increase in accretion expense. The following table presents total depletion expense, depletion as a percent of gas and oil production revenue and depletion expense per Mcfe for our operations for the respective periods (in thousands, except for percentage and per Mcfe data):

	Successor	Predecessor		
	Period From	Period From	Year Ended	Year Ended
	September 1	January	December 31,	December 31,
	through	1	December 31,	December 31,
	December 31,	through	2015	2014
	2016	August 31, 2016	2015	2014
Depletion expense:				
Total	\$ 21,011	\$64,049	\$ 138,850	\$ 223,735
Depletion expense as a percentage of gas and oil production revenue	24	% 46	% 39	% 48
Depletion per Mcfe	\$ 0.77	\$1.16	\$ 1.43	\$ 2.18

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties. Depletion expense, depletion expense as a percentage of gas and oil production revenues, and depletion expense per Mcfe during the Successor period from September 1, 2016 through December 31, 2016 generally decreased due to the application of fresh-start accounting to our proved properties on September 1, 2016 and lower production volumes. Depletion expense and depletion expense per Mcfe during the Predecessor period January 1, 2016 through August 31, 2016 generally decreased due to impairments of our Predecessor's proved properties recorded in the third and fourth quarters of 2015 as a result of lower forecasted commodity prices, which reduced the depletable cost basis of our proved gas and oil properties, and decreases in production volumes.

The decreases in depletion expense, depletion expense as a percentage of gas and oil production revenues, and depletion expense per Mcfe for the Predecessor year ended December 31, 2015 when compared with the Predecessor year ended December 31, 2014 are the result of the asset impairments recognized at September 30, 2015 and

December 31, 2014.

Asset Impairment. The \$966.6 million of asset impairment for the Predecessor year ended December 31, 2015 related to oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, net of \$85.8 million of future hedge gains reclassified from accumulated other comprehensive income. The \$573.8 million of asset impairment for the Predecessor year ended December 31, 2014 primarily consisted of \$555.7 million of oil and gas impairment within our Appalachian and mid-continent operations, which was net of \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income. In addition, \$18.1 million of asset impairment in 2014 was due to goodwill impairment. Asset impairments for the Predecessor year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014.

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Interest Expense. Interest expense during the Successor period from September 1, 2016 through December 31, 2016 consisted of \$7.4 million related to our First Lien Credit Facility, \$10.4 million related to our Second Lien Credit Facility, and \$0.7 million related to amortization of deferred financing costs. Interest expense during the Predecessor period from January 1, 2016 through August 31, 2016 consisted of \$32.6 million related to our Predecessor's Notes, \$15.7 million related to our Predecessor's Old First Lien Credit Facility, \$17.4 million related to our Predecessor's Old Second Lien Term Loan, \$15.4 related to amortization of deferred financing costs and debt discounts, partially offset by \$6.5 million in capitalized interest.

The \$40.0 million increase in our interest expense for the Predecessor year ended December 31, 2015 compared to the Predecessor year ended December 31, 2014 consisted of a \$23.1 million increase associated with our Predecessor's Old Term Loan Facility, an \$8.7 million increase associated with interest expense on our Predecessor's Senior Notes, \$5.6 million in accelerated amortization charges related to our Predecessor's reduced credit facility borrowing base and a \$3.0 million increase associated with amortization of our Predecessor's deferred financing costs, partially offset by a \$0.4 million decrease associated with outstanding borrowings under our Predecessor's revolving credit facility. The increase associated with our Predecessor's Senior Notes is primarily due to the issuance of an additional \$100.0 million of our Predecessor's 7.75% Senior Notes in June 2014 and an additional \$75.0 million of our Predecessor's 9.25% Senior Notes in October 2014. The increase in interest expense for our Predecessor's Old Term Loan Facility related to our Predecessor's entry into the Predecessor Old Term Loan Facility in February 2015.

Gain on Early Extinguishment of Debt. The gain on early extinguishment of debt for the Predecessor period from January 1, 2016 through August 31, 2016 represents a \$26.5 million gain related to the repurchase of a portion of our Predecessor's 7.75% and 9.25% Senior Notes. Of the \$26.5 million gain, \$27.4 million related to the gain from the redemption of the principal values and accrued interest, partially offset by \$0.9 million related to the accelerated amortization of the related deferred financing costs.

Reorganization Items, Net. Incremental costs incurred as a result of the Chapter 11 Filings, net gain on settlement of liabilities subject to compromise and reorganization adjustments, and net impact of fresh start adjustments are classified as "Reorganization items, net" in the Predecessor's consolidated statement of operations. The following table summarizes the reorganization items for the periods indicated (see Item 8: "Financial Statements and Supplementary Data – Note 3" for further information regarding our application of fresh start accounting and the related adjustments below):

	Successor Period from September 1 through December 31, 2016	Predecessor Period from January 1 through August 31, 2016
Professional fees and other	\$ (870)	\$ (33,065)
Accelerated amortization of deferred financing costs	—	(9,565)
Net gain on reorganization adjustments	—	361,479
Net loss on fresh start adjustments	—	(335,463)

Total reorganization items, net	\$ (870)	\$ (16,614)
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Other income (loss). The \$22.4 million of income for the Successor period from September 1, 2016 through December 31, 2016 represents primarily the \$22.4 million of non-cash income, net of consolidation and transfer adjustments, of certain Drilling Partnerships' consolidation and transfer of oil and gas properties and asset retirement obligations to us.

The \$9.2 million of loss for the Predecessor period from January 1, 2016 through August 31, 2016 represents primarily \$6.1 million of non-cash loss, net of consolidation and transfer adjustments, of certain Drilling Partnerships' consolidation and transfer of oil and gas properties and asset retirement obligations to our Predecessor and \$3.1 million of non-cash loss for the write-off of notes receivables with certain investors of our Predecessor's Drilling Partnerships.

Income Tax Expense (Benefit). For the Successor period from September 1, 2016 to December 31, 2016, we recorded a full valuation allowance against our net deferred tax asset balance, which reduced our effective tax rate to zero. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences between our accounting for certain revenue or expense items and their corresponding treatment for income tax purposes.

LIQUIDITY AND CAPITAL RESOURCES

General

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline and remain low in 2016. These lower commodity prices have negatively impacted our revenues, earnings and cash flows. Sustained low commodity prices could have a material and adverse effect on our liquidity position. In addition, challenges with our ability to raise capital through our Drilling Partnerships, either as a result of downturn in commodity prices or other difficulties affecting the fundraising channel, have negatively impacted our ability to remain in compliance with the covenants under our credit facilities.

We are not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. In addition to the \$30 million of indebtedness due on May 1, 2017, we classified the remaining \$666.8 million of outstanding indebtedness under our credit facilities as a current liability, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. In total, we have \$694.8 million of outstanding indebtedness under our credit facilities, which is net of \$2 million of deferred financing costs, as current portion of long term debt, net within our consolidated balance sheet as of December 31, 2016.

Subject to receiving the remaining lenders' consent, we expect to finalize an amendment to our First Lien Facility on April 19, 2017 in an attempt to ameliorate some of our liquidity concerns. The amendment is expected to provide for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity. Please see “—Credit Facilities—Credit Facility Amendment.”

Even following the amendment, we will continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. Please see “Risk Factors—Risks Related to Our Liquidity— Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time, and we are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet.”

Cash Flows

Successor	Predecessor		
Period From	Period From	Year Ended	Year Ended

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	September 1 through December 31, 2016	January 1 through August 31, 2016	December 31, 2015	December 31, 2014
Net cash provided by operating activities	\$ 33,693	\$ 221,106	\$ 172,804	\$ 202,823
Net cash used in investing activities	(24,333)	(24,894)	(204,002)	(896,443)
Net cash provided by (used in) financing activities	(342)	(182,137)	17,304	707,039

Cash Flows From Operating Activities:

Successor Period from September 1, 2016 through December 31, 2016

consists of \$36.4 million net cash provided by operating activities for cash receipts and disbursements attributable to our normal monthly operating cycle for gas and oil production and partnership management revenues, and collections net of payments for royalties, well construction and completion activities, Drilling Partnership administrative and oversight and well services activities, lease operating expenses, gathering, processing and transportation expenses, severance taxes, general and administrative expenses, and interest payments; partially offset by cash settlement payments of \$1.8 million on commodity derivative contracts; and

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reorganization costs of \$0.9 million representing incremental costs incurred as a result of our Predecessor's Chapter 11 Filings;

Predecessor Period from January 1, 2016 through August 31, 2016

consists of \$243.5 million sale of substantially all of our Predecessor's commodity hedge positions on July 25, 2016 and July 26, 2016 pursuant to our Predecessor's Restructuring Support Agreement; and cash settlement receipts of \$99.8 million on commodity derivative contracts; partially offset by \$84.8 million net cash used in operating activities for cash receipts and disbursements attributable to our Predecessor's normal monthly operating cycle for gas and oil production and partnership management revenues, and collections net of payments for royalties, well construction and completion activities, Drilling Partnership administrative and oversight and well services activities, lease operating expenses, gathering, processing and transportation expenses, severance taxes, general and administrative expenses, and interest payments; and reorganization costs of \$37.4 million incurred as a result of our Predecessor's Chapter 11 Filings; and Predecessor Year Ended December 31, 2015

consists of cash settlement receipts of \$179.1 million on commodity derivative contracts; partially offset by \$6.3 million net cash used in operating activities for cash receipts and disbursements attributable to our Predecessor's normal monthly operating cycle for gas and oil production and partnership management revenues, and collections net of payments for royalties, well construction and completion activities, Drilling Partnership administrative and oversight and well services activities, lease operating expenses, gathering, processing and transportation expenses, severance taxes, general and administrative expenses, and interest payments.

Cash Flows From Investing Activities:

Successor Period from September 1, 2016 through December 31, 2016

\$24.3 million in capital expenditures paid related to our drilling activities;

Predecessor Period from January 1, 2016 through August 31, 2016

\$24.9 million in capital expenditures paid related to our Predecessor's drilling activities;

Predecessor Year Ended December 31, 2015

\$127.1 million in capital expenditures paid related to our Predecessor's drilling activities; and \$77.9 million in net cash paid for acquisitions due to adjustments in working capital settlements for our Predecessor's Eagle Ford acquisition in 2015.

Cash Flows From Financing Activities:

Predecessor Period from January 1, 2016 through August 31, 2016

\$156.2 million in net repayments on our Predecessor's revolving credit facility; \$12.6 million in distributions paid to our Predecessor's unitholders; \$8.0 million in deferred financing costs primarily related to our Predecessor's revolving credit facility; and

\$5.5 million related to our Predecessor's senior note repurchases;
Predecessor Year Ended December 31, 2015

\$242.5 million in net borrowings under our Predecessor's second lien term loan;

\$93.6 million in net proceeds from the issuance of our Predecessor's common limited partner units under our
Predecessor's equity distribution programs; and

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\$6.8 million in net proceeds from the issuance of our Predecessor's preferred limited partner units under our Predecessor's equity distribution programs; partially offset by
\$147.8 million in distributions paid to our Predecessor's unitholders;
\$104.2 million in net repayments on our Predecessor's revolving credit facility;
\$44.9 million related to the Arkoma transaction adjustment; and
\$28.7 million in deferred financing costs primarily related to the issuance of our Predecessor's \$250.0 million second lien term loan.

Predecessor Year Ended December 31, 2015 Compared with the Predecessor Year Ended December 31, 2014:

The change in cash flows provided by operating activities when compared with the comparable prior year period was primarily due to:

- a decrease of \$216.8 million net cash provided by operating activities for cash receipts and disbursements attributable to our Predecessor's normal monthly operating cycle for gas and oil production and partnership management revenues, and collections net of payments for royalties, well construction and completion activities, Drilling Partnership administrative and oversight and well services activities, lease operating expenses, gathering, processing and transportation expenses, severance taxes, general and administrative expenses, and interest payments; partially offset by
- an increase of cash settlement receipts of \$186.8 million on commodity derivative contracts.

The change in cash flows used in investing activities when compared with the comparable prior year period was primarily due to:

- a decrease of \$609.0 million in net cash paid for acquisitions primarily due to the Rangely, Eagle Ford and GeoMet acquisitions in 2014, partially offset by the adjustments in working capital settlements for our Predecessor's Eagle Ford acquisition and the Arkoma acquisition in 2015; and
- a decrease of \$85.6 million in capital expenditures due to lower capital expenditures related to our Predecessor's drilling activities.

The change in cash flows provided by financing activities when compared with the comparable prior year period was primarily due to:

- an increase of \$381.2 million in net repayments on our Predecessor's revolving credit facility;
- a \$332.7 million decrease in net proceeds from the issuance of common limited partner units in the Predecessor year ended December 31, 2015 under our Predecessor's equity distribution programs;
- a decrease of \$170.6 million related to our Predecessor's senior note issuances during the Predecessor year ended December 31, 2014;
- a decrease of \$70.5 million in net proceeds from the issuance of preferred limited partner units in the Predecessor year ended December 31, 2015 primarily related to less funds required for acquisitions during 2015;
- an increase of \$32.5 million related to the Arkoma transaction adjustment reflected in the Predecessor year ended December 31, 2015; and
- an increase of \$15.9 million in deferred financing costs, distribution equivalent rights and other, primarily related to the issuance of our Predecessor's \$250.0 million second lien term loan during the Predecessor year ended December 31, 2015, partially offset by
- an increase of \$242.5 million in net borrowings under our Predecessor's second lien term loan facility due to the second lien term loan proceeds of \$242.5 million, net of \$7.5 million in discount, issued in the first half of 2015; and
- a decrease of \$71.2 million in distributions paid to unitholders primarily due to a reduction in our Predecessor's monthly cash distribution per common limited partner unit from \$0.58 per unit for the quarter ended December 31, 2013 that was paid in February 2014, \$0.1933 per unit paid in the month of March 2014 through the month of July 2014, and \$0.1966 per unit paid in the month of August 2014 through the month of February 2015 to \$0.1083 per unit paid in the month of March 2016 through the month of November 2015 due to the continued lower commodity

price environment. In addition,

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the monthly distribution was reduced to \$0.0125 per unit paid in December 2015 due to the continued lower commodity price environment.

Capital Requirements

At December 31, 2016, the capital requirements of our natural gas and oil production primarily consist of expenditures to maintain or increase production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures. The following table summarizes our total capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Successor Period From September 1 through December 31, 2016	Predecessor Period From January 1 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Total capital expenditures	\$ 24,333	\$ 24,894	\$ 127,138	\$ 212,728

During the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, our total capital expenditures consisted primarily of \$21.0 million and \$13.2 million, respectively, for wells drilled exclusively for our own account compared with \$51.2 million for the Predecessor year ended December 31, 2015, \$1.3 million and \$2.3 million, respectively, of leasehold acquisition costs compared with \$11.9 million for the Predecessor year ended December 31, 2015, \$1.5 million and \$0.7 million, respectively, of investments in our Drilling Partnerships compared with \$32.4 million for the Predecessor year ended December 31, 2015 and \$0.5 million and \$8.7 million, respectively, of corporate and other costs compared with \$31.6 million for the Predecessor year ended December 31, 2015.

During the Predecessor year ended December 31, 2015, our \$127.1 million of total capital expenditures consisted primarily of \$51.2 million for wells drilled exclusively for our own account compared with \$82.2 million for the comparable prior year period, \$32.4 million of investments in our Drilling Partnerships compared with \$72.4 million for the prior year comparable period, \$11.9 million of leasehold acquisition costs compared with \$25.5 million for the prior year comparable period and \$31.6 million of corporate and other costs compared with \$32.6 million for the prior year comparable period.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisitions in the future, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of December 31, 2016, we are committed to expend approximately \$20.4 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our Drilling Partnerships and borrowings under our revolving credit facility.

OFF BALANCE SHEET ARRANGEMENTS

We may enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2016, our off-balance sheet arrangements and transactions consist of operating lease arrangements, well drilling commitments, well completion service commitments, firm transportation agreements, software and data subscription agreements, and letters of credit, all of which are customary in our business. See “Contractual Obligations and Commercial Commitments” summarized below for more details related to these arrangements.

We proportionately consolidate our ownership interest of the asset retirement obligations of our Drilling Partnerships. At December 31, 2016, the Drilling Partnerships had \$18.5 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of our proportional interest in such liabilities. Under the terms of the respective partnership agreements, we maintain the right to retain a portion or all of the distributions to the limited partners of our Drilling Partnerships to cover the limited partners’ share of the plugging and abandonment costs up to a specified amount per month. As of December 31, 2016, we have withheld \$1.8 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. Our historical practice and continued intention is to retain distributions from the limited partners as the wells within each Drilling Partnership near the end of their useful life. On a partnership-by-partnership basis, we assess our right to withhold amounts related to plugging and abandonment costs based on several factors including commodity price trends, the natural decline in the production of the wells, and current and future costs. Generally, our intention is to retain distributions from the limited partners as the fair value of the future cash flows of the limited partners’ interest approaches the fair value of the future plugging and

abandonment cost. Upon our decision to retain all future distributions to the limited partners of our Drilling Partnerships, we will assume the related asset retirement obligations of the limited partners.

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally, for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of December 31, 2016, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table summarizes our contractual obligations at December 31, 2016 (in thousands):

	Total	Payments Due By Period			
		Less than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Contractual cash obligations:					
Total debt	\$696,831	\$696,831	\$—	\$—	\$—
Interest on total debt ⁽¹⁾	57,400	57,400	—	—	—
Operating leases	12,596	3,781	5,290	2,857	668
Total contractual cash obligations	\$766,827	\$758,012	\$5,290	\$2,857	\$668
		Amount of Commitment Expiration Per Period			
		Less than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Other commercial commitments:					
Standby letters of credit	\$3,451	\$3,451	\$—	\$—	\$—
Well drilling and completion commitments	19,445	19,445	—	—	—
Other commercial commitments ⁽²⁾	19,129	5,811	8,768	3,057	1,493
Total commercial commitments	\$42,025	\$28,707	\$8,768	\$3,057	\$1,493

(1) Interest expense on total debt includes our estimated cash and paid-in-kind interest for the next twelve months as our total debt is classified as a current liability. Actual interest expense may be different than our estimates

depending upon the timing and outcome of transactions related to our debts.

- (2) Our other commercial commitments include our throughput contracts, including future minimum firm transportation obligations for natural gas and gathering commitments, and software and data subscriptions. See “Item 1: Business - Contractual Revenue Arrangements” for a description of our firm transportation obligations for natural gas and gathering commitments.

CREDIT FACILITIES

First Lien Credit Facility

On September 1, 2016, we entered into a \$440 million First Lien Credit Facility agreement with Wells Fargo Bank, National Association (“Wells Fargo”), as administrative agent, and the lenders party thereto. A summary of the key provisions of the First Lien Credit Facility is as follows:

- Borrowing base of a \$410 million conforming reserve based tranche plus a \$30 million non-conforming tranche.
- Provides for the issuance of letters of credit, which reduce borrowing capacity.
- The non-conforming tranche matures on May 1, 2017 and the conforming reserve-based tranche matures on August 23, 2019.

Borrowing base will be redetermined semi-annually, with additional interim re-determinations permitted under certain circumstances. The first scheduled borrowing base redetermination shall occur on May 1, 2017; provided, that a super majority of the lenders may elect, in certain circumstances, to seek an interim redetermination of the borrowing base prior to May 1, 2017.

Obligations are secured by mortgages on substantially all of our oil and gas properties and first priority security interests in substantially all of our assets and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

Borrowings bear interest at our election at either LIBOR plus an applicable margin between 3.00% and 4.00% per annum or the “alternate base rate” plus an applicable margin between 2.00% and 3.00% per annum, which fluctuates based on utilization. We are also required to pay a fee of 0.50% per annum on the unused portion of the borrowing base. At December 31, 2016, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 5.0%.

Contains covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of our assets.

Requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017.

Requires us to maintain certain financial ratios (which will use an annualized EBITDA measurement for periods prior to June 30, 2017):

Total Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 5.00 to 1.00;

Current assets to current liabilities (each as defined in the First Lien Credit Facility) of not less than 1.00 to 1.00;

First Lien Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 3.50 to 1.00; and

EBITDA to Interest Expense (each as defined in the First Lien Credit Facility) of not less than 2.50 to 1.00.

Certain of the above financial ratios are expected to be amended. See “Credit Facility Amendment” below for further description.

Second Lien Credit Facility

On September 1, 2016, we entered into an amended and restated second lien credit agreement with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto (the “Second Lien Credit Facility”) for an aggregate principal amount of \$252.5 million maturing on February 23, 2020. A summary of the key provisions of the Second Lien Credit Facility is as follows:

Until May 1, 2017, interest will be payable at a rate of 2% in cash plus paid-in-kind interest at a rate equal to the Adjusted LIBO Rate (as defined in the Second Lien Credit Facility) plus 9% per annum. During the subsequent 15-month period, cash and paid-in-kind interest will vary based on a pricing grid tied to our leverage ratio under the First Lien Credit Facility. After such 15-month period, interest will accrue at a rate equal to the Adjusted LIBO Rate plus 9% per annum and will be payable in cash.

All prepayments are subject to the following premiums, plus accrued and unpaid interest:

4.5% of the principal amount prepaid for prepayments prior to February 23, 2017;

2.25% of the principal amount prepaid for prepayments on or after February 23, 2017 and prior to February 23, 2018; and

no premium for prepayments on or after February 23, 2018.

Obligations are secured on a second priority basis by security interests in the same collateral securing the First Lien Credit Facility and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

- Contains covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions, engage in other business activities, and other covenants substantially similar to those in the First Lien Credit Facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables.

Requires us to maintain certain financial ratios (the financial ratios will use an annualized EBITDA measurement for periods prior to June 30, 2017):

EBITDA to Interest Expense (each as defined in the Second Lien Credit Facility) of not less than 2.50 to 1.00;

Total Leverage Ratio (as defined in the Second Lien Credit Facility) of no greater than 5.5 to 1.0 prior to December 31, 2017 and no greater than 5.0 to 1.0 thereafter; and

current assets to current liabilities (each as defined in the Second Lien Credit Facility) of not less than 1.0 to 1.0.

Credit Facility Amendment

We are not in compliance with certain of the financial covenants under our Credit Facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. In addition to the \$30 million of indebtedness due on May 1, 2017, we classified the remaining \$666.8 million of outstanding indebtedness under our credit facilities as a current liability, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. In total, we have \$694.8 million of outstanding indebtedness under our credit facilities, which is net of \$2 million of deferred financing costs, as current portion of long term debt, net within our consolidated balance sheet as of December 31, 2016.

On April 19, 2017, we expect to enter into an amendment to the First Lien Facility. Pursuant to the amendment, certain of the financial ratio covenants will be revised upwards. Specifically, beginning December 31, 2017, we are required to maintain a ratio of Total Debt to EBITDA (each as defined in the First Lien Facility) of not more than 5.50 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 5.00 to 1.00 thereafter. We are also required, beginning December 31, 2017, to maintain a ratio of First Lien Debt (as defined in the First Lien Facility) to EBITDA of not more than 4.00 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 3.50 to 1.00 thereafter.

In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a “going concern” qualification. The First Lien lenders’ waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Facility.

The First Lien amendment will confirm the conforming and non-conforming tranches of the borrowing base at \$410 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$330 million by August 31, 2017 and to \$190 million by October 1, 2017 (subject to extension at the administrative agent’s option to October 31, 2017). Similarly, the non-conforming tranche of the borrowing base will be required to be reduced to \$10 million by November 1, 2017. In addition, we will be required to use excess asset sale proceeds (after application in accordance with the existing

terms of the First Lien Facility) to repay outstanding borrowings and reduce the applicable borrowing base to the required level.

Unless we are able to obtain an amendment or waiver, the lenders under our Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without a going concern qualification. However, pursuant to the intercreditor agreement, the lenders under the Second Lien Facility are restricted in their ability to pursue remedies for 180 days from any such notice of default. As of the date hereof, the lenders under the Second Lien Facility have not yet given us notice of any default.

SECURED HEDGE FACILITY

At December 31, 2016, we have a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our First Lien Credit Facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as the ultimate general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

An event of default occurred under the secured hedging facility agreement upon our filing of voluntary petitions for relief under Chapter 11. The lenders under the secured hedge facility agreed to forbear from exercising remedies in respect of such event of default while the Chapter 11 Filings were pending and, upon occurrence of the effective date of the Plan contemplated by the Restructuring Support Agreement, such event of default is no longer be deemed to exist or to continue under the secured hedge facility.

In addition, it will be an event of default under our First Lien Credit Facility if we, as the ultimate general partner of the Drilling Partnerships, breach an obligation governed by the secured hedge facility, and the effect of such breach is to cause amounts owing under swap agreements governed by the secured hedge facility to become immediately due and payable.

ISSUANCE OF SHARES

As of the Plan Effective Date, we had 5,416,667 shares of our common equity outstanding. Titan Management holds our Series A Preferred Share, which entitles Titan Management to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such

estimates and assumptions include revenue and expense accruals, depletion and impairment of gas and oil properties, fair value of derivative instruments, fair value of certain gas and oil properties and asset retirement obligations, and fair value of assets and liabilities in connection with the application of fresh-start accounting. We summarize our significant accounting policies within our consolidated financial statements included in “Item 8: Financial Statements and Supplementary Data – Notes 2, 3 and 7” included in this report. Our critical accounting policies and estimates are discussed below.

Gas and Oil Properties – Depletion and Impairment

We follow the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs to enhance or evaluate development of proved fields or areas are capitalized. All other geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed.

Our depletion expense is determined on a field-by-field basis using the units-of-production method. Depletion rates for leasehold acquisition costs are based on estimated proved reserves, and depletion rates for well and related equipment costs are based

on proved developed reserves associated with each field. Depletion rates are determined based on reserve quantity estimates and the capitalized costs of undeveloped and developed producing properties. We also consider the estimated salvage value in the calculation of depreciation, depletion and amortization. Capitalized costs of developed producing properties in each field are aggregated to include our costs of property interests in proportionately consolidated Drilling Partnerships, joint venture wells, wells drilled solely by us for our interests, properties purchased and working interests with other outside operators.

We review our gas and oil properties for impairment whenever events or changes in circumstances indicate that the net carrying amount of an asset may not be recoverable. Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions. Additional factors impacting the economic viability of long-lived assets are discussed under “Item 1A: Risk Factors” in this report. If it is determined that an asset’s estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

Our unproved properties are assessed individually based on several factors including if a dry hole has been drilled in the area, other wells drilled in the area and operating results, remaining months in the lease’s primary term, and management’s future plans to drill and develop the area. As exploration and development work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depletion. If exploration activities are unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of impairment of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

The review of our proved oil and gas properties is done on a field-by-field basis by determining if the net carrying value of proved properties is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on management’s plans to continue to produce and develop proved reserves. Expected future cash flows from the sale of production of reserves are calculated based on estimated future prices. We estimate prices based upon current contracts in place, adjusted for basis differentials and market related information including published future prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected undiscounted future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Our reserve estimates for our investment in the Drilling Partnerships are based on our own assumptions, rather than our proportionate share of the Drilling Partnerships’ reserves, which include our actual capital contributions, a disproportionate share of salvage value upon plugging of the wells and lower operating and administrative costs. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. Our reserve estimates are based upon reserve analyses that rely upon various assumptions, including those required by the SEC, as to natural gas, oil and natural gas liquids prices, drilling and operating expenses, capital expenditures and availability of funds. Reserve estimates for wells with limited or no production history are less reliable than those based on actual production. Estimated reserves are often subject to future revisions, which could be substantial, based

on the availability of additional information which could cause the assumptions to be modified. We cannot predict what reserve revisions may be required in future periods. Any significant variance in these assumptions could materially affect the estimated net cash flows expected to be generated by the asset. As discussed in “General Trends and Outlook” within this section, recent increases in natural gas and oil drilling have driven an increase in the supply of natural gas and oil and put a downward pressure on domestic prices. Further declines in commodity prices may result in additional impairment charges in future periods.

There were no impairments of unproved gas and oil properties recorded by us during the Successor period from September 1, 2016 through December 31, 2016, during the Predecessor period from January 1, 2016 through August 31, 2016 and for the Predecessor year ended December 31, 2014. During the Predecessor year ended December 31, 2015, our Predecessor recognized \$6.6 million of asset impairments related to its unproved gas and oil properties for its unproved acreage in the New Albany Shale, which was impaired due to expiring acreage and no intention to pursue development, and was recorded within asset impairments on our Predecessor’s consolidated statement of operations.

During the Successor period from September 1, 2016 through December 31, 2016 and during the Predecessor period from January 1, 2016 through August 31, 2016, there were no impairments of proved gas and oil properties. For the Predecessor year ended December 31, 2015, our Predecessor recognized \$960.0 million of asset impairment related to proved oil and gas properties in the

Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, net of \$85.8 million of future hedge gains reclassified from accumulated other comprehensive income. During the Predecessor year ended December 31, 2014, our Predecessor recognized \$555.7 million of asset impairments related to proved oil and gas properties within its Appalachian and mid-continent operations, which was net of \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the Predecessor year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014 through the impairment testing date in January 2015. These impairments related to the carrying amounts of these gas and oil properties being in excess of our Predecessor's estimate of their fair values at December 31, 2015 and 2014. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of commodity prices at the date of measurement.

Fair Value Measurements

We have established a hierarchy to measure our financial instruments at fair value, which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 – Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 – Unobservable inputs that reflect the entity's own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Derivatives. We use a market approach fair value methodology to value the assets and liabilities for our outstanding derivative contracts. Our commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 fair value measurements.

Reorganization Value. We estimated the fair value of our enterprise value and reorganizational value of assets and liabilities upon emergence from bankruptcy through fresh-start accounting utilizing the discounted cash flow method. To estimate fair value utilizing the discounted cash flow method, we established an estimate of future cash flows for both our gas and oil production business and our partnership management business based on the financial projections in our disclosure statement. The financial projections for our gas and oil production business were based on our forecast, which included a number of assumptions regarding future anticipated performance of reserves including decline curves for existing proved developed producing wells, as well as new wells brought online, commodity pricing and average realized pricing, and reductions for operating costs and general and administrative expenses. The financial projections for our partnership management business were based on our forecast, which included a number of assumptions regarding future anticipated performance including existing fee revenue streams and future annual partnership capital fund raises, based on historical averages. A terminal value was included for the partnership management business, and was calculated using a long-term growth rate of 1% on the projected cash flows of the final year of the forecast period.

The discount rates of 10% for our gas and oil production business and 12% for our partnership management business were estimated based on an after-tax weighted average cost of capital ("WACC") derived from a comparable set of publicly-held companies reflecting the rate of return that would be expected by a market participant within each

respective business. The WACC also takes into consideration a company-specific risk premium, reflecting the risk associated with the overall uncertainty of the financial projections used to estimate future cash flows. The resulting fair value of our equity was used to value shares issued under our incentive plan. Our enterprise value and reorganizational value of assets and liabilities estimates of fair value are all Level 3 measurements as they are based on unobservable inputs.

The fair value allocated to our proved natural gas and oil properties and support equipment and other were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair value of unproved properties was the result of the excess reorganization value over the fair value of identified tangible and intangible assets and represents the value of our probable and possible drilling locations within our various acreage positions. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

The fair value allocated to our asset retirement obligations was measured using a discounted cash flow model based on management's historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements.

We used the discount rate consistent with the rate used for our gas and oil production business. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

Partnership Consolidations. We estimated the fair values of natural gas and oil properties transferred to our Predecessor upon consolidation of certain Drilling Partnerships based on discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, our future operating and development costs of the assets, the respective natural gas, oil and natural gas liquids forward price curves and estimated salvage values using our historical experience and external estimates of recovery values. We estimated the fair value of asset retirement obligations transferred to our Predecessor upon consolidation of certain Drilling Partnerships based on discounted cash flow projections using our historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future considering inflation rates, federal and state regulatory requirements, and a discount rate consistent with that used in valuing the related natural gas and oil properties consolidated. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

Acquisitions. During the Predecessor year ended December 31, 2014, our Predecessor completed several acquisitions of oil and gas properties and related assets. The fair value measurements of assets acquired and liabilities assumed were based on inputs that were not observable in the market and therefore represented Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were measured under our then existing methodology for recognizing an estimated liability for the plugging and abandonment of our gas and oil wells. These inputs required significant judgments and estimates by management at the time of the valuation. All purchase price allocations were finalized within one year from the acquisition date.

Reserve Estimates

Our estimates of proved natural gas, oil and natural gas liquids reserves and future net revenues from them are based upon reserve analyses that rely upon various assumptions, including those required by the SEC, as to natural gas, oil and natural gas liquids prices, drilling and operating expenses, capital expenditures and availability of funds. The accuracy of these reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates. We engaged independent third-party reserve engineers to prepare annual reports of our proved reserves (see “Item 2: Properties”).

Any significant variance in the assumptions utilized in the calculation of our reserve estimates could materially affect the estimated quantity of our reserves. As a result, our estimates of proved natural gas, oil and natural gas liquids reserves are inherently imprecise. Actual future production, natural gas, oil and natural gas liquids prices, revenues, development expenditures, operating expenses and quantities of recoverable natural gas, oil and natural gas liquids reserves may vary substantially from our estimates or estimates contained in the reserve reports and may affect our ability to pay amounts due under our credit facility or cause a reduction in our credit facility. In addition, our proved reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas, oil and natural gas liquids prices, mechanical difficulties, governmental regulation and other factors, many of which are beyond our control. Our reserves and their relation to estimated future net cash flows impact the calculation of impairment and depletion of oil and gas properties. Adjustments to quarterly depletion rates, which are based upon a units of production method, are made concurrently with changes to reserve estimates. Generally, an increase or decrease in reserves without a corresponding change in capitalized costs will have a corresponding inverse impact to depletion expense.

Asset Retirement Obligations

We estimate the cost of future dismantlement, restoration, reclamation and abandonment of our operating assets.

We recognize an estimated liability for the plugging and abandonment of our gas and oil wells and related facilities. We also recognize a liability for our future asset retirement obligations if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset.

The estimated liability is based on our historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free interest rate. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Since there are many variables in estimating asset retirement obligations, we attempt to limit the impact of management's judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. We have no assets legally restricted for purposes of settling asset retirement obligations. Except for our gas and oil properties, we believe that there are no other material retirement obligations associated with tangible long lived assets.

RECENTLY ISSUED ACCOUNTING STANDARDS

See “Item 8: Financial Statements and Supplementary Data – Note 2” to the consolidated financial statements for additional information related to recently issued accounting standards..

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in interest rates and commodity prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of the market risk-sensitive instruments were entered into for purposes other than trading.

General

All of our assets and liabilities are denominated in U.S. dollars, and as a result, we do not have exposure to currency exchange risks.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and interest rate cap and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2016. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

We are subject to the risk of loss on our derivative instruments that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require (i) the evaluation of potential counterparties’ financial condition to determine their credit worthiness; (ii) the quarterly monitoring of our oil, natural gas and NGLs counterparties’ credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords us netting or set off opportunities to mitigate exposure risk; and (v) when appropriate requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our liabilities related to derivatives as of December 31, 2016 represent financial instruments from nine counterparties; all of which are financial institutions that have an “investment grade” (minimum Standard & Poor’s rating of BBB+ or better) credit rating and are lenders associated with our revolving credit facility. Subject to the terms of our revolving credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the revolving credit facility.

Interest Rate Risk. At December 31, 2016, \$435.8 million was outstanding under our revolving credit facility and \$261.0 million was outstanding under our term loan facility. Holding all other variables constant, a hypothetical 1% change in variable interest rates would change our consolidated interest expense for the twelve-month period ending December 31, 2017 by approximately \$7.0 million.

Commodity Price Risk. Our market risk exposure to commodities is due to the fluctuations in the commodity prices and the impact those price movements have on our financial results. To limit our exposure to changing commodity prices, we use financial derivative instruments, including financial swap and option instruments, to hedge portions of our future production. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under these swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Option instruments are contractual agreements that grant the right, but not the obligation, to purchase or sell commodities at a fixed price for the relevant period.

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our consolidated operating income for the twelve-month period ending December 31, 2017 of approximately \$3.8 million.

Realized pricing of our natural gas, oil, and NGL production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production has been volatile and unpredictable for many years. To limit our exposure to changing natural gas, oil and NGL prices, we enter into natural gas and oil swap and put option contracts. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter (“OTC”) futures contracts with qualified counterparties. OTC contracts are generally financial contracts which are settled with financial payments or receipts and generally do not require delivery of physical hydrocarbons. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. Crude oil contracts are based on a West Texas Intermediate (“WTI”) index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price.

At December 31, 2016, we had the following commodity derivatives:

	Production		
	Period		Average
	Ending		Fixed
Type	December 31,	Volumes ⁽¹⁾	Price ⁽¹⁾
Natural Gas – Fixed Price Swaps	2017	51,679,700	\$3.140
	2018	47,559,300	\$2.959
Crude Oil – Fixed Price Swaps	2017	1,188,700	\$46.971
	2018	1,011,100	\$49.544

(1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.

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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 Shareholders

Titan Energy, LLC

We have audited the accompanying consolidated balance sheet of Titan Energy, LLC and subsidiaries (collectively, “Titan”) as of December 31, 2016, and the related consolidated statements of operations, comprehensive income (loss), changes in members’ equity (deficit), and cash flows for the period September 1, 2016 to December 31, 2016, and the consolidated balance sheet of Atlas Resource Partners, L.P. and subsidiaries (collectively, the “Partnership” and together with Titan, the “Company”) as of December 31, 2015, and the related consolidated statements of operations, comprehensive income (loss), changes in partners’ capital (deficit), and cash flows for the period January 1, 2016 to August 31, 2016 and each of the two years in the period ended December 31, 2015. 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 Titan Energy, LLC and subsidiaries as of December 31, 2016, and the results of their operations and their cash flows for the period September 1, 2016 to December 31, 2016, and the financial position of Atlas Resource Partners, L.P. and subsidiaries as of December 31, 2015, and the results of their operations and their cash flows for the period January 1, 2016 to August 31, 2016 and each of the two years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Notes 2 and 7 to the consolidated financial statements, as of December 31, 2016, the Company was not in compliance with certain debt covenants under its credit facilities. The Company does not have sufficient liquidity to repay all of its current debt obligations. The Company’s business plan for 2017, which is also described in Note 2, contemplates asset sales, obtaining additional working capital, and the refinancing or restructuring of its credit agreements to long-term arrangements, or other modifications to its capital structure. The Company’s ability to achieve the foregoing elements of its business plan, which may be necessary to permit the realization of assets and satisfaction of liabilities in the ordinary course of business, is uncertain and raises substantial doubt about its ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 2 to the consolidated financial statements, on August 26, 2016, the United States Bankruptcy Court for the Southern District of New York entered an order confirming the plan of reorganization, which became effective on September 1, 2016. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852, Reorganizations, for Titan as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods as described in Note 3.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

April 17, 2017

TITAN ENERGY, LLC

CONSOLIDATED BALANCE SHEETS

(in thousands)

	Successor December 31, 2016	Predecessor December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 24,446	\$ 1,353
Accounts receivable	33,728	63,367
Advances to affiliates	4,145	—
Current portion of derivative asset	—	159,460
Subscriptions receivable	5,656	19,877
Prepaid expenses and other	18,125	22,935
Total current assets	86,100	266,992
Property, plant and equipment, net	784,723	1,191,611
Goodwill and intangible assets, net	—	14,095
Long-term derivative asset	—	198,262
Other assets, net	11,011	28,989
Total assets	\$ 881,834	\$ 1,699,949
LIABILITIES AND MEMBERS' EQUITY / PARTNERS' CAPITAL (DEFICIT)		
Current liabilities:		
Accounts payable	\$ 30,161	\$ 49,249
Advances from affiliates	—	9,924
Liabilities associated with drilling contracts	10,656	21,483
Current portion of derivative liability	34,799	—
Derivative payable to Drilling Partnerships	—	2,574
Accrued well drilling and completion costs	4,933	26,914
Accrued interest	1,789	25,436
Distribution payable	—	4,334
Accrued liabilities	19,551	22,086
Current portion of long-term debt	694,810	—
Total current liabilities	796,699	162,000
Long-term debt, less current portion, net	—	1,503,427
Long-term derivative liability	14,615	—
Asset retirement obligations	75,347	113,740
Other long-term liabilities	2,114	5,410
Commitments and contingencies (Note 11)		
Members' Equity (Deficit)/Partners' Capital (Deficit):		
General partner's interest	—	(31,156)

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Preferred limited partners' interests	—	188,739
Class C common limited partner warrants	—	1,176
Common limited partners' interests	—	(262,762)
Accumulated other comprehensive income	—	19,375
Series A Preferred members' interest	(145)	—
Common shareholders' interest	(6,796)	—
Total members' deficit/partners' deficit	(6,941)	(84,628)
Total liabilities and members' deficit/partners' deficit	\$ 881,834	\$ 1,699,949

See accompanying notes to consolidated financial statements.

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TITAN ENERGY, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share and unit data)

	Successor Period from	Predecessor Period from		
	September 1, 2016 through December 31, 2016	January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues:				
Gas and oil production	\$ 86,936	\$ 139,094	\$ 356,999	\$470,051
Well construction and completion	2,326	19,157	76,505	173,564
Gathering and processing	2,159	3,929	7,431	14,107
Administration and oversight	708	1,263	7,812	15,564
Well services	3,704	11,226	23,822	24,959
Gain (loss) on mark-to-market derivatives	(43,892)	(23,916)	267,223	2,819
Other, net	247	317	241	590
Total revenues	52,188	151,070	740,033	701,654
Costs and expenses:				
Gas and oil production	39,418	86,566	169,653	182,226
Well construction and completion	2,023	16,658	66,526	150,925
Gathering and processing	3,048	5,893	9,613	15,525
Well services	2,036	4,677	9,162	10,007
General and administrative	18,496	58,004	65,968	72,349
Depreciation, depletion and amortization	23,877	82,331	157,978	239,923
Asset impairment	—	—	966,635	573,774
Total costs and expenses	88,898	254,129	1,445,535	1,244,729
Operating loss	(36,710)	(103,059)	(705,502)	(543,075)
Interest expense	(18,327)	(74,587)	(102,133)	(62,144)
Gain (loss) on asset sales and disposal	180	(479)	(1,181)	(1,869)
Gain on early extinguishment of debt	—	26,498	—	—
Reorganization items, net	(870)	(16,614)	—	—
Other income (loss)	22,413	(9,189)	—	—
Loss before income taxes	(33,314)	(177,430)	(808,816)	(607,088)
Income tax expense (benefit) – (Note 12)	—	—	—	—
Net loss	(33,314)	(177,430)	(808,816)	(607,088)

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Preferred member / limited partner dividends	—	(4,013)	(16,469)	(19,267)
Net loss attributable to common shareholders and preferred member)	\$ (33,314	\$ —	\$ —
Net loss attributable to common limited partners and the general partner	\$ —	\$ (181,443)	\$ (825,285)	\$ (626,355)
Allocation of net loss attributable to:				
Series A Preferred member	\$ (666)	\$ —	\$ —	\$ —
Common shareholders	\$ (32,648)	\$ —	\$ —	\$ —
Common limited partners' interest	\$ —	\$ (177,814)	\$ (811,266)	\$ (628,926)
General partner's interest	\$ —	\$ (3,629)	\$ (14,019)	\$ 2,571
Net loss attributable to common shareholders per share / common limited partners per unit (Note 2):				
Basic	\$ (6.03)	\$ (1.72)	\$ (8.65)	\$ (8.42)
Diluted	\$ (6.03)	\$ (1.72)	\$ (8.65)	\$ (8.42)
Weighted average shares / common limited partner units outstanding (Note 2):				
Basic	5,418	102,912	93,745	74,716
Diluted	5,418	102,912	93,745	74,716

See accompanying notes to consolidated financial statements.

TITAN ENERGY, LLC

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in thousands)

	Successor Period from September 1, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Net loss	\$ (33,314)	\$ (177,430)	\$ (808,816)	\$ (607,088)
Other comprehensive income (loss):				
Derivative instruments designated as cash flow hedges:				
Mark-to-market gains during the period	—	—	—	238,875
Reclassification adjustment for unrealized gains used to offset impairment expense	—	—	(85,768)	(82,324)
Reclassification to net loss of mark-to-market gains	—	(10,758)	(86,328)	7,739
Reclassification adjustment for net reorganization gain included in net loss	—	(8,617)	—	—
Total other comprehensive income (loss)	—	(19,375)	(172,096)	164,290
Comprehensive loss attributable to Series A Preferred member and common shareholders	\$ (33,314)	\$ —	\$ —	\$ —
Comprehensive loss attributable to common and preferred limited partners and the general partner	\$ —	\$ (196,805)	\$ (980,912)	\$ (442,798)

See accompanying notes to consolidated financial statements.

TITAN ENERGY, LLC

CONSOLIDATED STATEMENT OF CHANGES IN MEMBERS' E QUITY (DEFICIT) / PARTNERS' CAPITAL (DEFICIT)

(in thousands, except unit data)

	Preferred Limited		Class C	Class D		Class E		Common Limited		Class C Common Limited	Partner Warrants	
	Partners' Interest Class B	Interest		Amount	Units	Amount	Units	Amount	Units			Partners' Interests
Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	
4,482	3,836,554	96,539	3,749,986	86,938	—	—	—	—	59,448,308	917,417	562,497	1,111
(3,870)	—	—	—	—	—	—	—	—	—	(8,481)	—	—
—	—	—	—	—	3,200,000	77,301	—	—	21,860,000	426,290	—	—
—	—	—	—	—	—	—	—	—	241,733	7,391	—	—
(1,378)	—	(8)	—	(737)	—	(1,974)	—	—	—	(16,779)	—	—
(15,502)	—	(9,704)	—	(9,486)	—	—	—	—	—	(184,303)	—	—
—	—	—	—	—	—	—	—	—	—	(2,158)	—	—
—	(3,796,900)	(94,614)	—	—	—	—	—	—	3,796,900	94,614	—	—
2,571	—	8,770	—	8,786	—	1,711	—	—	—	(628,926)	—	—

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—	—	—	—	—	—	—	—	—	—	—	—	—
\$(13,697)	39,654	\$983	3,749,986	\$85,501	3,200,000	\$77,038	—	\$—	85,346,941	\$605,065	562,497	\$1,1
—	—	—	—	—	—	—	—	—	—	(44,893)	—	—
—	—	—	—	—	890,328	20,911	256,083	5,845	16,303,451	93,635	—	—
—	—	—	—	—	—	—	—	—	470,615	5,056	—	—
1,339	—	8	—	100	—	(231)	—	(172)	—	15,502	—	—
(4,779)	—	(42)	—	(7,849)	—	(8,492)	—	(345)	—	(126,288)	—	—
—	—	—	—	—	—	—	—	—	—	(558)	—	—
—	(39,654)	(985)	—	—	—	—	—	—	39,859	985	—	—
(14,019)	—	36	—	7,650	—	8,292	—	491	—	(811,266)	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—
\$(31,156)	—	\$—	3,749,986	\$85,402	4,090,328	\$97,518	256,083	\$5,819	102,160,866	\$(262,762)	562,497	\$1,1
—	—	—	—	—	—	—	—	—	245,175	204	—	—
—	—	—	—	—	—	—	—	—	24,679	1,160	—	—

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39	——	637	—	2,205	—	172	—	1,277	—	—
(156)	——	(2,550)	—	(4,410)	—	(344)	—	(5,118)	—	—
—	——	—	—	—	—	—	—	(11)	—	—
(3,629)	——	1,275	—	2,540	—	198	—	(177,814)	—	—
—	——(3,749,986)	(84,764)	—	—	—	—	3,749,986	85,940	(562,497)	(1,176)
—	——	—	—	—	—	—	—	—	—	—
5,953)	34,902	——	—	(4,090,328)	(97,853)	(256,083)	(5,845)	(106,180,706)	357,124	—
\$—	\$—	\$—	—	\$—	—	\$—	—	\$—	—	\$—

	Series A Preferred		Common Shareholders'		Total Members'
Successor	Member's Interest Shares	Interest Amount	Interest Shares	Amount	Equity (Deficit)
Balance at September 1, 2016	1	\$521	5,416,667	\$25,495	\$26,016
Net issued and unissued shares under incentive plans	—	—	31,120	357	357
Net loss	—	(666)	—	(32,648)	(33,314)
Balance at December 31, 2016	1	\$(145)	5,447,787	\$(6,796)	\$(6,941)

See accompanying notes to consolidated financial statements.

TITAN ENERGY, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Successor Period from September 1, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net loss	\$ (33,314)	\$ (177,430)	\$ (808,816)	\$ (607,088)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Depreciation, depletion and amortization	23,877	82,331	157,978	239,923
Asset impairment	—	—	966,635	573,774
Non-cash reorganization items	—	(10,312)	—	—
(Gain) loss on derivatives	43,360	7,346	(226,743)	—
(Gain) loss on asset sales and disposal	(180)	479	1,181	1,869
Gain on extinguishment of debt	—	(26,498)	—	—
Other (income) loss	(22,533)	9,189	—	—
Non-cash compensation expense	357	1,167	4,944	8,067
Non-cash interest expense	8,522	—	—	—
Provision for losses on Drilling Partnership receivables	—	10,906	—	—
Valuation allowance on deferred tax asset	—	1,596	—	—
Amortization of deferred financing costs and discount and premium on long-term debt	660	15,385	19,640	9,191
Changes in operating assets and liabilities:				
Monetization of derivatives	—	243,552	—	—
Accounts receivable, prepaid expenses and other	(3,751)	97,791	132,559	(77,476)
Accounts payable and accrued liabilities	16,695	(34,396)	(74,574)	54,563
Net cash provided by operating activities	33,693	221,106	172,804	202,823
CASH FLOWS FROM INVESTING ACTIVITIES:				
Capital expenditures	(24,333)	(24,894)	(127,138)	(212,728)
Net cash paid for acquisitions	—	—	(77,854)	(686,811)
Other	—	—	990	3,096
Net cash used in investing activities	(24,333)	(24,894)	(204,002)	(896,443)

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CASH FLOWS FROM FINANCING ACTIVITIES:

Borrowings under revolving credit facility	—	135,000	661,342	1,393,000
Repayments under revolving credit facility	—	(291,191)	(523,000)	(1,116,000)
Net proceeds from senior note issuances	—	—	—	170,596
Senior note repurchases	—	(5,528)	—	—
Distributions paid to shareholders/unitholders	—	(12,578)	(147,795)	(218,995)
Net proceeds from issuance of common limited partner units	—	204	93,635	426,290
Net proceeds from issuance of preferred units	—	—	6,778	77,301
Arkoma transaction adjustment	—	—	(44,893)	(12,351)
Deferred financing costs, distribution equivalent rights and other	(342)	(8,044)	(28,763)	(12,802)
Net cash provided by (used in) financing activities	(342)	(182,137)	17,304	707,039
Net change in cash and cash equivalents	9,018	14,075	(13,894)	13,419
Cash and cash equivalents, beginning of period	15,428	1,353	15,247	1,828
Cash and cash equivalents, end of period	\$ 24,446	\$ 15,428	\$ 1,353	\$ 15,247

See accompanying notes to consolidated financial statements.

TITAN ENERGY, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – ORGANIZATION

We are an independent developer and producer of natural gas, crude oil and NGLs with operations in basins across the United States. We sponsor and manage tax-advantaged investment partnerships (the “Drilling Partnerships”), in which we coinvest, to finance a portion of our natural gas, crude oil and NGL production activities. As discussed further below, we are the successor to the business and operations of Atlas Resource Partners, L.P. (“ARP”). Unless the context otherwise requires, references to “Titan Energy, LLC,” “Titan,” “the Company,” “we,” “us,” and “our,” refer to Titan Energy, LLC and our consolidated subsidiaries (and our predecessor, where applicable).

Titan Energy Management, LLC (“Titan Management”) manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members’ equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of Atlas Energy Group, LLC (“Atlas Energy Group” or “ATLS”; OTC: ATLS), which is a publicly traded company.

In addition to its preferred member interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (“AGP”), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

At December 31, 2016, we had 5,447,787 common shares representing limited liability company interests issued and outstanding.

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the “Restructuring Support Agreement”) with (i) lenders holding 100% of ARP’s senior secured revolving credit facility (the “First Lien Lenders”), (ii) lenders holding 100% of ARP’s second lien term loan (the “Second Lien Lenders”) and (iii) holders (the “Consenting Noteholders”) and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that became party to the Restructuring Support Agreement, the “Restructuring Support Parties”) of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the “7.75% Senior Notes”) and the 9.25% Senior Notes due 2021 (the “9.25% Senior Notes”) and, together with the 7.75% Senior Notes, the “Notes”) of ARP’s subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the “Issuers”). Under the Restructuring Support Agreement, the Restructuring Support Parties agreed, subject to certain terms and conditions, to support ARP’s restructuring (the “Restructuring”) pursuant to a pre-packaged plan of reorganization (the “Plan”).

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 in the United States Bankruptcy Court for the Southern District of New York (the “Bankruptcy Court,” and the cases commenced thereby, the “Chapter 11 Filings”). The cases commenced thereby were jointly administered under the caption “In re: ATLAS RESOURCE PARTNERS, L.P., et al.”

ARP operated its businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords were unimpaired by the Plan and were satisfied in

full in the ordinary course of business, and ARP's existing trade contracts and terms were maintained. To assure ordinary course operations, ARP obtained interim approval from the Bankruptcy Court on a variety of "first day" motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to ARP, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the "Plan Effective Date"), pursuant to the Plan, the following occurred:

- the First Lien Lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than \$440 million of principal and face amount of letters of credit) and became lenders under our first lien exit facility credit agreement, composed of a \$410 million conforming reserve-based tranche and a \$30 million non-conforming tranche (Refer to Note 7 – Debt for further information regarding terms and provisions).
- the Second Lien Lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of \$252.5 million (Refer to Note 7 – Debt for further information regarding terms and provisions). In

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addition, the Second Lien Lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.

holders of the Notes, in exchange for 100% of the \$668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

all of ARP's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended.

Titan Management, a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. Four of the seven initial members of the board of directors were designated by Titan Management (the "Titan Class A Directors"). For so long as Titan Management holds such preferred share, the Titan Class A Directors will be appointed by a majority of the Titan Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

NOTE 2 – BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

In connection with the Chapter 11 Filings, we were subject to the provisions of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 852 Reorganizations ("ASC 852"). All expenses, realized gains and losses and provisions for losses directly associated with the bankruptcy proceedings were classified as "reorganization items" in the consolidated statements of operations.

Upon emergence from bankruptcy on the Plan Effective Date, we adopted fresh-start accounting in accordance with ASC 852 (see Note 3). Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Plan Effective Date, which differed materially from the recorded values of ARP's assets and liabilities as reflected in ARP's historical consolidated balance sheet. The effects of the Plan and the application of fresh-start accounting were reflected in our consolidated financial statements as of September 1, 2016 and the related adjustments thereto were recorded in our consolidated statements of operations as reorganization items for the predecessor period January 1 to August 31, 2016.

As a result, our consolidated balance sheet and consolidated statement of operations subsequent to the Plan Effective Date is not comparable to ARP's consolidated balance sheet and consolidated statements of operations prior to the Plan Effective Date. Our consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented on or after September 1, 2016 and dates prior. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

References to "Successor" relate to the Company on and subsequent to the Plan Effective Date. References to "Predecessor" refer to the Company prior to the Plan Effective Date. The consolidated financial statements of the

Successor have been prepared assuming that the Company will continue as a going concern and contemplate the realization of assets and the satisfaction of liabilities in the normal course of business.

Principles of Consolidation

Our consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. Transactions between us and other ATLS managed operations have been identified in the consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

In accordance with established practice in the oil and gas industry, our consolidated financial statements include our pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the Drilling Partnerships in which we have an interest. Such interests generally approximates 10-30%. Our consolidated financial statements do not include

proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, we calculate these items specific to our own economics.

Liquidity, Capital Resources, and Ability to Continue as a Going Concern

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline and remain low in 2016. These lower commodity prices have negatively impacted our revenues, earnings and cash flows. Sustained low commodity prices could have a material and adverse effect on our liquidity position. In addition, challenges with our ability to raise capital through our Drilling Partnerships, either as a result of downturn in commodity prices or other difficulties affecting the fundraising channel, have negatively impacted our ability to remain in compliance with the covenants under our credit facilities.

We are not in compliance with certain of the financial covenants under our credit facilities (as described in Note 7) as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. In addition to the \$30 million of indebtedness due on May 1, 2017, we classified the remaining \$666.8 million of outstanding indebtedness under our credit facilities as a current liability, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. In total, we have \$694.8 million of outstanding indebtedness under our credit facilities, which is net of \$2 million of deferred financing costs, as current portion of long term debt, net within our consolidated balance sheet as of December 31, 2016.

On April 19, 2017, we expect to enter into an amendment to the First Lien Facility. Pursuant to the amendment, certain of the financial ratio covenants will be revised upwards. Specifically, beginning December 31, 2017, we are required to maintain a ratio of Total Debt to EBITDA (each as defined in the First Lien Facility) of not more than 5.50 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 5.00 to 1.00 thereafter. We are also required, beginning December 31, 2017, to maintain a ratio of First Lien Debt (as defined in the First Lien Facility) to EBITDA of not more than 4.00 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 3.50 to 1.00 thereafter.

In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a “going concern” qualification. The First Lien lenders’ waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Facility.

The First Lien amendment will confirm the conforming and non-conforming tranches of the borrowing base at \$410 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$330 million by August 31, 2017 and to \$190

million by October 1, 2017 (subject to extension at the administrative agent's option to October 31, 2017). Similarly, the non-conforming tranche of the borrowing base will be required to be reduced to \$10 million by November 1, 2017. In addition, we will be required to use excess asset sale proceeds (after application in accordance with the existing terms of the First Lien Facility) to repay outstanding borrowings and reduce the applicable borrowing base to the required level.

Unless we are able to obtain an amendment or waiver, the lenders under our Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without a going concern qualification. However, pursuant to the intercreditor agreement, the lenders under the Second Lien Facility are restricted in their ability to pursue remedies for 180 days from any such notice of default. As of the date hereof, the lenders under the Second Lien Facility have not yet given us notice of any default.

We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, strengthening our balance sheet and meeting our debt service obligations. We could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options, but there is no certainty that we will be able to implement any such options, and we cannot provide any assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders. In addition, we expect that we will sell a significant amount of non-core assets in the near future to comply with the requirements of our expected First Lien Facility amendment and to attempt to enhance our liquidity.

We cannot assure you that we would be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that would be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions would allow us to meet our debt obligations and capital requirements.

Arkoma Acquisition

On June 5, 2015, ARP acquired coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma from ATLS (the “Arkoma Acquisition”) for \$31.5 million, net of purchase price adjustments, which was funded through the issuance of 6,500,000 of our Predecessor’s common limited partner units. We determined that the Arkoma Acquisition constituted a transaction between entities under common control and, accordingly, retroactively adjusted ARP’s prior period consolidated financial statements assuming our Predecessor’s common limited partners participated in the net income (loss) of the Arkoma operations before the date of the transaction.

In April 2015, the FASB updated the accounting guidance for earnings per unit (“EPU”) of master limited partnerships (“MLP”) applying the two-class method. The updated accounting guidance specifies that for general partner transfers (or “drop downs”) to an MLP accounted for as a transaction between entities under common control, the earnings (losses) of the transferred business before the date of the transaction should be allocated entirely to the general partner’s interest, and previously reported EPU of the limited partners should not change. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the drop down transaction occurs are also required.

We adopted this accounting guidance upon its effective date of January 1, 2016, which resulted in the following retrospective restatement to allocate the net income (loss) of the Arkoma operations before the date of the transaction entirely to our Predecessor’s general partner’s interest:

	Previously		
	Filed	Adjustment	Restated
Predecessor Consolidated Statement of Operations Year Ended December 31, 2015:			
Common limited partners' interest	\$ (808,780)	\$ (2,486)	\$ (811,266)
General partner's interest	\$ (16,505)	\$ 2,486	\$ (14,019)
Net loss attributable to common limited partners per unit – basic	\$ (8.63)	\$ (0.02)	\$ (8.65)

Prior to the Arkoma Acquisition, our Predecessor's common limited partners did not participate in the net income (loss) of the Arkoma operations. Subsequent to the Arkoma Acquisition, our Predecessor's common limited partners participated in the net income (loss) of the Arkoma operations, which was determined after the deduction of our Predecessor's general partner's and preferred unitholders' interests.

Use of Estimates

The preparation of our consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. Our consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, fair value of derivative instruments, fair value of certain gas and oil properties and asset retirement obligations, and fair value of assets and liabilities in connection with the application of fresh-start accounting and accounting for business combinations. The oil and gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Actual results could differ from those estimates.

Cash Equivalents

We consider all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments.

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with our operations. We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customers' current creditworthiness. We extend credit on sales on an unsecured basis to many of our customers. At December 31, 2016 and 2015, we had recorded no allowance for uncollectible accounts receivable on our consolidated balance sheets.

Inventory

We had \$7.4 million and \$8.0 million of inventory at December 31, 2016 and 2015, respectively, which was included within prepaid expenses and other current assets on our consolidated balance sheets. We value inventories at the lower of cost or market. Our inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method. During the year ended December 31, 2015, we recognized a \$1.2 million loss on asset sales and disposal on our consolidated statement of operations related to the obsolescence of our pipe, pump units and other inventory in the New Albany Shale and Black Warrior basin.

Subscriptions Receivable

We receive contributions from limited partner investors of our Drilling Partnerships, which are used to fund well drilling activities within the programs. Limited partner investors in the Drilling Partnerships execute an investment agreement with Anthem Securities, Inc. ("Anthem"), a registered broker-dealer and our wholly owned subsidiary, through third-party broker dealers, which is then delivered to Anthem. The investor contributions are then remitted to Anthem at a later date. Limited partner investor contributions are non-refundable upon the execution of an investment agreement. We recognize the contributions associated with the executed investment agreements but for which

contributions have not yet been received at the respective balance sheet date as subscriptions receivable.

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs that generally do not extend the useful life of an asset for two years or more through the replacement of critical components are expensed as incurred. Major renewals and improvements that generally extend the useful life of an asset for two years or more through the replacement of critical components are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset's estimated useful life. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our results of operations.

We follow the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are

charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs to enhance or evaluate development of proved fields or areas are capitalized. All other geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil and NGLs are converted to gas equivalent basis (“Mcf”) at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

Our depletion expense is determined on a field-by-field basis using the units-of-production method. Depletion rates for leasehold acquisition costs are based on estimated proved reserves, and depletion rates for well and related equipment costs are based on proved developed reserves associated with each field. Depletion rates are determined based on reserve quantity estimates and the capitalized costs of undeveloped and developed producing properties. We also consider the estimated salvage value in the calculation of depreciation, depletion and amortization. Capitalized costs of developed producing properties in each field are aggregated to include our costs of property interests in proportionately consolidated Drilling Partnerships, joint venture wells, wells drilled solely by us for our interests, properties purchased and working interests with other outside operators.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to our consolidated statement of operations. Upon the sale of an individual well, we credit the proceeds to accumulated depreciation and depletion within our consolidated balance sheet. Upon our sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in our consolidated statement of operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

Support equipment and other are carried at cost and consist primarily of pipelines, processing and compression facilities, and gathering systems and related support equipment. We compute depreciation of support equipment and other using the straight-line balance method over the estimated useful life of each asset category as follows: Pipelines, processing and compression facilities: 15-20 years; Buildings and land improvements: 3-40 years; Other support equipment: 3-10 years.

See Note 5 for additional disclosures regarding property, plant and equipment.

Impairment of Property, Plant and Equipment

We review our property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset’s estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

Our unproved properties are assessed individually based on several factors including if a dry hole has been drilled in the area, other wells drilled in the area and operating results, remaining months in the lease’s primary term, and management’s future plans to drill and develop the area. As exploration and development work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depletion. If exploration activities are unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of impairment of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

The review of our oil and gas properties is done on a field-by-field basis by determining if the historical cost of proved properties less the applicable accumulated depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on our plans to continue to produce and develop proved reserves. Expected future cash flows from the sale of production of

reserves are calculated based on estimated future prices. We estimate prices based upon current contracts in place, adjusted for basis differentials and market related information including published future prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected undiscounted future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, our reserve estimates for our investments in the Drilling Partnerships are based on our own assumptions rather than our proportionate share of the Drilling Partnerships' reserves. These assumptions include our actual capital contributions, a disproportionate share of salvage value upon plugging of the wells and lower operating and administrative costs.

Our lower operating and administrative costs result from recognizing our proportionate share of limited partners' Drilling Partnership external operating expenses. These assumptions could result in our calculation of depletion and impairment being different than our proportionate share of the Drilling Partnerships' calculations for these items. In addition, reserve estimates for wells with limited or no production history are less reliable than those based on actual production. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information which could cause the assumptions to be modified. We cannot predict what reserve revisions may be required in future periods.

Our method of calculating our reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships. Our reserve quantities include reserves in excess of our proportionate share of reserves in Drilling Partnerships, which we may be unable to recover due to the Drilling Partnerships' legal structure. We may have to pay additional consideration in the future as a Drilling Partnership's wells become uneconomic to the Drilling Partnership under the terms of the Drilling Partnership's drilling and operating agreement in order to recover these excess reserves, in addition to us becoming responsible for paying associated future operating, development and plugging costs of the well interests acquired, and to acquire any additional residual interests in the wells held by the Drilling Partnership's limited partners. The acquisition of any such uneconomic well interest from a Drilling Partnership by us is governed under the Drilling Partnership's limited partnership agreement. In general, we will seek consent from the Drilling Partnership's limited partners to acquire the well interests from the Drilling Partnership based upon our determination of fair market value.

See Note 5 for additional disclosures regarding impairment of property, plant and equipment.

Capitalized Interest

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds during the Successor period September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 2015 and 2014 was 7.6%, 6.5%, 6.5% and 5.6%, respectively. The aggregate amount of interest capitalized during the Successor period September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014 was \$0.1 million, \$6.5 million, \$15.8 million and \$13.0 million, respectively.

Intangible Assets

We recorded our intangible assets with finite lives in connection with partnership management and operating contracts acquired through prior consummated acquisitions. We amortize contracts acquired on a declining balance method over their respective estimated useful lives. We evaluate intangible assets for impairment annually or whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

We had a \$0.5 million net carrying amount of intangible assets recorded within goodwill and intangible assets, net on our consolidated balance sheet at December 31, 2015. Amortization expense on our intangible assets during the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014 was \$0.5 million, \$0.2 million, and \$0.3 million, respectively. We do not have any intangible assets recorded on our consolidated balance sheet at December 31, 2016 and did not record any amortization expense during the Successor period from September 1, 2016 through December 31, 2016.

Goodwill

We evaluate goodwill for impairment annually or whenever impairment indicators arise by comparing our reporting units' estimated fair values to their carrying values. Because quoted market prices for the reporting units are not available, we must apply judgment in determining the estimated fair value of our reporting units. We use all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in our assets. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to our market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including ours, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the fair value calculations have been determined, we also consider the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in our industry. The

resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in our industry to determine whether those valuations appear reasonable in management's judgment.

As a result of our Predecessor's goodwill impairment evaluation at December 31, 2014, our Predecessor recognized an \$18.1 million non-cash impairment charge within asset impairments in the consolidated statement of operations for the year ended December 31, 2014. The goodwill impairment resulted from the reduction in our Predecessor's estimated fair value of its gas and oil production reporting unit in comparison to its carrying amount at December 31, 2014. Our Predecessor's estimated fair value of its gas and oil production reporting unit was impacted by a decline in overall commodity prices during the fourth quarter of 2014. The \$13.6 million remaining goodwill at December 31, 2014 and 2015 was attributable to our Predecessor's well construction and completion and other partnership management reporting units that was recorded in connection with prior consummated acquisitions. No changes in the carrying amount of goodwill was recorded during the Predecessor period from January 1, 2016 through August 31, 2016 and the year ended December 31, 2015. As a result of the adoption of fresh start accounting, our Predecessor's goodwill was eliminated (see Note 3).

Derivative Instruments

We enter into certain financial contracts to manage our exposure to movement in commodity prices. The derivative instruments recorded in the consolidated balance sheets were measured as either an asset or liability at fair value. Changes in a derivative instrument's fair value are recognized currently in our consolidated statements of operations unless specific hedge accounting criteria are met. On January 1, 2015, our Predecessor discontinued hedge accounting through de-designation for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value after December 31, 2014 of these derivatives were recognized immediately within gain (loss) on mark-to-market derivatives in our consolidated statements of operations, while the fair values of the instruments recorded in accumulated other comprehensive income as of December 31, 2014 were reclassified to the consolidated statement of operations in the periods in which the respective derivative contracts settled. Prior to discontinuance of hedge accounting, the fair value of commodity derivative instruments was recognized in accumulated other comprehensive income (loss) within partners' capital (deficit) on our Predecessor's consolidated balance sheet and reclassified to the consolidated statement of operations at the time the originally hedged physical transactions affected earnings. See Note 8 for additional disclosures regarding derivative instruments.

Other Assets

In April 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs. The updated accounting guidance requires that debt issuance costs be presented as a direct deduction from the associated debt obligation. We adopted this accounting guidance upon its effective date of January 1, 2016. The retrospective effect of the reclassification resulted in the following changes to our consolidated balance sheet:

	Previously		
Predecessor Consolidated Balance Sheet	Filed	Adjustment	Restated
December 31, 2015:			
Other assets, net	\$60,044	\$ (31,055)	\$28,989
Long-term debt, net	\$1,534,482	\$ (31,055)	\$1,503,427

Deferred financing costs related to revolving credit facility (line-of-credit) arrangements are recorded at cost, amortized over the term of the arrangement, and are presented net of accumulated amortization within other assets, net on our consolidated balance sheets. If our revolving credit facility's borrowing base is reduced, we will accelerate amortization of the deferred financing costs to correspond to the lower borrowing base. We had revolving credit facility deferred financing costs of \$3.8 million and \$19.8 million, which were net of \$0.5 million and \$29.1 million of accumulated amortization, recorded within other assets, net on our consolidated balance sheets at December 31, 2016 and 2015, respectively. For the Successor period September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 2015 and 2014, amortization expense of revolving credit facility deferred financing costs was \$0.5 million, \$10.6 million, \$13.6 million and \$7.3 million, respectively, which was recorded within interest expense on our consolidated statements of operations.

At December 31, 2016 and 2015, we had notes receivable with certain investors of our Drilling Partnerships of \$0.6 million and \$3.7 million, respectively, recorded within other assets, net on our consolidated balance sheets. The notes have a maturity date of March 31, 2022, and a 2.25% per annum interest rate. The maturity date of the notes can be extended to March 31, 2027, subject to certain conditions, including an extension fee of 1.0% of the outstanding principal balance. For the Predecessor period from January 1, 2016 through August 31, 2016, we recognized \$3.1 million provision for losses to adjust the notes receivables to their net realizable value, which was recorded within other income (loss) on our consolidated statement of operations. For the Successor period

September 1, 2016 through December 31, 2016 and the Predecessor years ended December 2015 and 2014, we did not record any provision for losses related to notes receivables.

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our gas and oil wells and related facilities. We recognize a liability for our future asset retirement obligations in the current period if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. See Note 6 for additional disclosures regarding asset retirement obligations.

Share-Based Compensation

We recognize all share-based payments to employees, including grants of employee options, in the consolidated financial statements based on their fair values. See Note 15 for additional disclosures regarding share-based compensation.

Predecessor's Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to our Predecessor's common limited partners per unit was computed by dividing net income (loss) attributable to our Predecessor's common limited partners, which was determined after the deduction of our Predecessor's general partner's and preferred unitholders' interests, by the weighted average number of our Predecessor's common limited partner units outstanding during the period. Net income (loss) attributable to our Predecessor's common limited partners was determined by deducting net income (loss) attributable to participating securities, if applicable, income (loss) attributable to our Predecessor's preferred limited partners and net income (loss) attributable to our Predecessor's general partner's Class A units. Our Predecessor's general partner's interest in net income (loss) was calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 14), with a priority allocation of net income to our Predecessor's general partner's incentive distributions, if any, in accordance with our Predecessor's partnership agreement, and the remaining net income (loss) allocated with respect to our Predecessor's general partner's and limited partners' ownership interests.

Our Predecessor presented net income (loss) per unit under the two-class method for MLPs, which considers whether the incentive distributions of a MLP represent a participating security. The two-class method considers whether our Predecessor's partnership agreement contained any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights' share of currently designated available cash for distributions as defined under our Predecessor's partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, we believe our Predecessor's partnership agreement contractually limited cash distributions to available cash; therefore, undistributed earnings were not allocated to the incentive distribution rights.

Unvested unit-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. Phantom unit awards, which consist of common units issuable under the terms of our long-term incentive plan, contain non-forfeitable rights to distribution equivalents. The participation rights would result in a non-contingent transfer of value each time we declare a distribution or distribution equivalent right during the award's vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. As such, the net income utilized in the calculation of net income (loss) per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net income allocated to our Predecessor's common limited partners for purposes of calculating net income attributable to our Predecessor's common limited partners per unit (in thousands, except unit data):

	Predecessor Period from		
	January 1		
	through	Year Ended	Year Ended
	August 31,	December 31,	December 31,
	2016	2015	2014
Net loss	\$(177,430)	\$ (808,816)	\$ (607,088)
Preferred limited partner dividends	(4,013)	(16,469)	(19,267)
Net loss attributable to common limited partners and the general partner	(181,443)	(825,285)	(626,355)
Less: General partner's interest	(3,629)	(14,019)	2,571
Net loss attributable to common limited partners	(177,814)	(811,266)	(628,926)
Less: Net loss attributable to participating securities – phantom units	—	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit – Basic	(177,814)	(811,266)	(628,926)
Plus: Convertible preferred limited partner dividends ⁽¹⁾	—	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit – Diluted	\$(177,814)	\$ (811,266)	\$ (628,926)

(1) For all predecessor periods presented, distributions on our Predecessor's Class B and Class C convertible preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

Diluted net income (loss) attributable to our Predecessor's common limited partners per unit was calculated by dividing net income (loss) attributable to our Predecessor's common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, convertible preferred units and warrants, as calculated by the treasury stock or if converted methods, as applicable. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of our long-term incentive plan.

The following table sets forth the reconciliation of our Predecessor's weighted average number of common limited partner units used to compute basic net income attributable to our Predecessor's common limited partners per unit with those used to compute diluted net income attributable to our Predecessor's common limited partners per unit (in thousands):

Predecessor Period from	Year Ended	Year Ended
January 1,	December 31,	December 31,

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	2016 through	2015	2014
	August 31,		
	2016		
Weighted average number of common limited partner units—basic	102,912	93,745	74,716
Add effect of dilutive incentive awards ⁽¹⁾	—	—	—
Add effect of dilutive convertible preferred limited partner units ⁽²⁾	—	—	—
Weighted average number of common limited partner units—diluted	102,912	93,745	74,716

(1) For the period January 1, 2016 through August 31, 2016 and years ended December 31, 2015 and 2014, 274,000, 453,000 and 783,000 phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

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(2) For the period January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014, potential common limited partner units issuable upon conversion of our Predecessor's Class B preferred units and potential common limited partner units issuable upon (a) conversion of our Predecessor's Class C preferred units and (b) exercise of the common unit warrants issued with our Predecessor's Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As our Predecessor's Class D and Class E preferred units were convertible only upon a change of control event, they were not considered dilutive securities for earnings per unit purposes.

Concentration of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist principally of periodic temporary investments of cash and cash equivalents. We place our temporary cash investments in high-quality short-term money market instruments and deposits with high-quality financial institutions and brokerage firms. We had \$41.3 million and \$10.3 million, respectively, in deposits at various banks at December 31, 2016 and 2015, respectively, of which \$38.2 million and \$8.4 million, respectively, were over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments to date.

Cash on deposit at various banks may differ from the balance of cash and cash equivalents at period end due to certain reconciling items, including any outstanding checks as of period end.

We sell natural gas, crude oil and NGLs under contracts to various purchasers in the normal course of business. For the Successor period September 1, 2016 through December 31, 2016, Tenaska Marketing Ventures and Chevron within our gas and oil production segment individually accounted for approximately 22% and 15%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the Predecessor period January 1, 2016 through August 31, 2016, Tenaska Marketing Ventures, Chevron and Interconn Resources LLC within our gas and oil production segment individually accounted for approximately 25%, 16% and 13%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the Predecessor year ended December 31, 2015, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC within our gas and oil production segment individually accounted for approximately 21%, 15%, 11% and 11%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the Predecessor year ended December 31, 2014, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC within our gas and oil production segment individually accounted for approximately 25%, 15%, 14% and 13%, respectively, of our natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity.

We are subject to the risk of loss on our derivative instruments that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the quarterly monitoring of our oil, natural gas and NGLs counterparties' credit exposures; (iii) comprehensive credit reviews of significant counterparties to physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords us netting or set off opportunities to mitigate exposure risk; and (v) when appropriate requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our liabilities related to derivatives as of December 31, 2016 represent financial instruments from nine counterparties; all of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of BBB+ or better) credit rating and are lenders associated with our revolving credit facility. Subject to the terms of our revolving credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the revolving credit facility.

Revenue Recognition

Natural gas and oil production. We generally sell natural gas, crude oil and NGLs at prevailing market prices. Typically, our sales contracts are based on pricing provisions that are tied to a market index, with certain fixed adjustments based on proximity to gathering and transmission lines and the quality of our natural gas. Generally, the market index is fixed two business days prior to the commencement of the production month. Revenue and the related accounts receivable are recognized when produced quantities are delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Revenues from the production of natural gas, crude oil and NGLs, in which we have an interest with other producers, are recognized on the basis of our percentage ownership of the working interest and/or overriding royalty.

Drilling Partnerships. Certain energy activities are conducted by us through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are

entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we will recognize a current liability titled “Liabilities Associated with Drilling Contracts” on our consolidated balance sheet. After the Drilling Partnership well is completed and turned in line (i.e. wells that have been drilled, completed, and connected to a gathering system), we are entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees we are entitled to receive for services provided, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which is generally between 10-30%. We recognize our Drilling Partnership management fees in the following manner:

- ◆ **Well construction and completion.** For each well that is drilled by a Drilling Partnership, we receive a 15% mark-up on those costs incurred to drill and complete wells included within the partnership. Such fees are earned, in accordance with each Drilling Partnership’s partnership agreement, and recognized as the services are performed, typically between 60 and 270 days.
- ◆ **Administration and oversight.** For each well drilled by a Drilling Partnership, we receive a fixed fee between \$100,000 and \$500,000, depending on the type of well drilled, which is earned in accordance with each Drilling Partnership’s partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of \$75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed.
- ◆ **Well services.** Each Drilling Partnership pays us a monthly per well operating fee, currently \$1,000 to \$2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed.

While the historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of cumulative unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

Gathering and processing revenue. Gathering and processing revenue includes gathering fees we charge to the Drilling Partnership wells for our processing plants in the New Albany and the Chattanooga Shales. Generally, we charge a gathering fee to the Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of the Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge the Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

Our gas and oil production operations accrue unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon

volumetric data and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices and/or contract market prices. We had unbilled revenues at December 31, 2016 and 2015 of \$29.1 million and \$37.7 million, respectively, which were included in accounts receivable within our consolidated balance sheets.

Comprehensive Income (Loss)

Accumulated other comprehensive income was eliminated pursuant to the application of fresh-start accounting (see Note 3). Prior to that, our Predecessor's comprehensive income (loss) included net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, had not been recognized in the calculation of net income (loss). These changes, other than net income (loss), were referred to as "other comprehensive income (loss)" on our Predecessor's consolidated financial statements, and for all periods presented, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 8). Our Predecessor did not have any other type of transaction which would be included within other comprehensive income (loss).

Recently Issued Accounting Standards

In February 2016, the FASB updated the accounting guidance related to leases. The updated accounting guidance requires lessees to recognize a lease asset and liability at the commencement date of all leases (with the exception of short-term leases), initially measured at the present value of the lease payments. The updated guidance is effective for us as of January 1, 2019 and requires a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest period presented. We are currently in the process of determining the impact that the updated accounting guidance will have on our consolidated financial statements.

In November 2015, the FASB updated the accounting guidance related to the balance sheet presentation of deferred taxes. The updated accounting guidance requires that all deferred tax liabilities and assets be classified as noncurrent in a classified balance sheet. The current requirement that deferred tax liabilities and assets of a tax-paying component of an entity be offset and presented as a single amount is not affected by the amendments in this update. This guidance is effective for us beginning January 1, 2017, with early adoption permitted. We early adopted this guidance in the fourth quarter of 2016 on a prospective basis; therefore, prior periods were not retrospectively adjusted.

In August 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs specific to line of credit arrangements. The updated accounting guidance allows the option of presenting deferred debt issuance costs related to line-of-credit arrangements as an asset, and subsequently amortizing over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. We adopted the updated accounting guidance effective January 1, 2016, and it did not have a material impact on our consolidated financial statements.

In February 2015, the FASB updated the accounting guidance related to consolidation under the variable interest entity and voting interest entity models. The updated accounting guidance modifies the consolidation guidance for variable interest entities, limited partnerships and similar legal entities. We adopted this accounting guidance upon its effective date of January 1, 2016, and it did not have a material impact on our consolidated financial statements.

In August 2014, the FASB updated the accounting guidance related to the evaluation of whether there is substantial doubt about an entity's ability to continue as a going concern. The updated accounting guidance requires an entity's management to evaluate whether there are conditions or events that raise substantial doubt about its ability to continue as a going concern within one year from the date the financial statements are issued and provide footnote disclosures, if necessary. We adopted this accounting guidance on January 1, 2016, and provided enhanced disclosures, as applicable, within our consolidated financial statements.

In May 2014, the FASB updated the accounting guidance related to revenue recognition. The updated accounting guidance provides a single, contract-based revenue recognition model to help improve financial reporting by providing clearer guidance on when an entity should recognize revenue, and by reducing the number of standards to which an entity has to refer. In July 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The updated accounting guidance provides companies with alternative methods of adoption. We are evaluating the impact of this updated accounting guidance on our consolidated financial statements, and based on the continuing evaluation of our revenue streams, this accounting guidance is not expected to have a material impact on our net income (loss). This accounting guidance will require that our revenue recognition policy disclosures include further detail regarding our performance obligations as to the nature, amount, timing, and estimates of revenue and cash flows generated from our contracts with customers. We are still in the process of determining whether or not we will use the retrospective method or the modified retrospective approach to implementation.

NOTE 3 – FRESH START ACCOUNTING

Upon our emergence from bankruptcy, we adopted fresh-start accounting in accordance with ASC 852. We qualified for fresh-start accounting because (i) the reorganization value of our assets immediately prior to the confirmation of the Plan was less than the post-petition liabilities and allowed claims, and (ii) the holders of existing voting shares of our Predecessor received less than 50% of the voting shares of the post-emergence Successor entity.

Reorganization Value: Reorganization value represents the fair value of the Successor's total assets and is intended to approximate the amount a willing buyer would pay for the assets immediately after restructuring. Under fresh-start accounting, we allocated the reorganization value to our individual assets based on their estimated fair values.

Our reorganization value was derived from an estimate of enterprise value. Enterprise value represents the estimated fair value of an entity's long term debt and shareholders' equity. The estimated enterprise value of the Successor of approximately \$714.3 million represents management's best estimate of fair value on the Plan Effective Date and is within the range of value contemplated by the Bankruptcy Court in confirmation of the Plan after extensive negotiations among the Company and its creditors.

We estimated the enterprise value of the Successor utilizing the discounted cash flow method. To estimate fair value utilizing the discounted cash flow method, we established an estimate of future cash flows for both our gas and oil production business and our partnership management business based on the financial projections in our disclosure statement. The financial projections for our gas and oil production business were based on our forecast, which included a number of assumptions regarding future anticipated performance of reserves including decline curves for existing proved developed producing wells, as well as new wells brought online, commodity pricing and average realized pricing, and reductions for operating costs and general and administrative expenses. The financial projections for our partnership management business were based on our forecast, which included a number of assumptions regarding future anticipated performance including existing fee revenue streams and future annual partnership capital fund raises, based on historical averages. A terminal value was included for the partnership management business, and was calculated using a long-term growth rate of 1% on the projected cash flows of the final year of the forecast period.

The discount rates of 10% for our gas and oil production business and 12% for our partnership management business were estimated based on an after-tax weighted average cost of capital (“WACC”) derived from a comparable set of publicly-held companies reflecting the rate of return that would be expected by a market participant within each respective business. The WACC also takes into consideration a company-specific risk premium, reflecting the risk associated with the overall uncertainty of the financial projections used to estimate future cash flows.

A reconciliation of the reorganization value was provided in the table below:

Enterprise value	\$714,325
Plus: Cash and cash equivalents	15,428
Plus: Working capital surplus	63,222
Plus: Other liabilities	70,183
Reorganization value of Successor assets	\$863,158

Consolidated Balance Sheet

The adjustments set forth in the following consolidated balance sheet reflect the effect of the consummation of the transactions contemplated by the Plan (reflected in the column “Reorganization Adjustments”) as well as fair value adjustments as a result of the adoption of fresh-start accounting (reflected in the column “Fresh Start Adjustments”). The explanatory notes highlight methods used to determine fair values or other amounts of the assets and liabilities as well as significant assumptions or inputs.

	Predecessor			Successor
	August 31,	Reorganization	Fresh Start	September
	2016	Adjustments	Adjustments	1,
				2016
ASSETS				
Current assets:				
Cash and cash equivalents	\$ 35,688	\$ (20,260)	(a) \$ —	\$ 15,428
Accounts receivable	56,621	—	(56)	(a) 56,565
Advances to affiliates	5,592	—	—	5,592
Prepaid expenses and other	18,635	—	—	18,635
Total current assets	116,536	(20,260)	(56)	96,220
Property, plant and equipment, net	1,154,866	—	(396,661)	(b) 758,205
Goodwill	13,639	—	(13,639)	(c) —
Other assets, net	15,773	(7,040)	(b) —	8,733
Total assets	\$ 1,300,814	\$ (27,300)	\$ (410,356)	\$ 863,158
LIABILITIES AND PARTNERS' CAPITAL (DEFICIT)/ MEMBERS' EQUITY				
Current liabilities:				
Accounts payable	\$ 49,324	\$ —	\$ —	\$ 49,324
Derivative payable to Drilling Partnerships	534	—	—	534
Current portion of derivative liability	3,087	—	—	3,087
Accrued well drilling and completion costs	12,322	—	—	12,322
Accrued interest	3,210	(3,210)	(c) —	—
Accrued liabilities	18,311	—	(2,774)	(d) 15,537
Current portion of long-term debt	30,000	—	—	30,000
Total current liabilities	116,788	(3,210)	(2,774)	110,804
Long-term debt, less current portion, net	405,809	250,346	(d) —	656,155
Long-term derivative liability	4,259	—	—	4,259
Asset retirement obligations	130,935	—	(72,067)	(e) 58,868
Other long-term liabilities	7,108	—	(52)	(f) 7,056
Liabilities subject to compromise	915,626	(915,626)	(e) —	—
Commitments and contingencies (Note 11)				
Partners' Capital (Deficit) / Members' Equity:				
General partner's interest	\$(34,902)	\$ 34,902	(f) —	—
Preferred limited partners' interests	103,698	(103,698)	(f) —	—
Common limited partners' interests	(357,124)	357,124	(f) —	—
Accumulated other comprehensive income	8,617	(8,617)	(f) —	—

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Series A Preferred member's interest	—	7,230	(g)	(6,709)(g)	521
Common shareholders' interests	—	354,249	(g)	(328,754)(g)	25,495
Total partners' deficit / members' equity	(279,711)	641,190		(335,463)		26,016
Total liabilities and partners' deficit / members' equity	\$ 1,300,814	\$ (27,300)		\$ (410,356)		\$ 863,158

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Reorganization Adjustments:

(a) Reflects the use of cash on the Plan Effective Date from implementation of the Plan:

First Lien Credit Facility deferred financing costs	\$(2,525)
Second Lien Credit Facility deferred financing costs	(1,838)
Accrued interest on old first lien credit facility	(3,210)
Accrued interest on old second lien credit facility	(2,375)
Professional fees	(10,312)
Total uses	\$(20,260)

(b) Reflects the adjustment made to record the elimination of \$9.6 million of the old first lien credit facility deferred financing costs offset by the recognition of \$2.5 million in additional deferred financing costs related to the new First Lien Credit Facility.

(c) Reflects the payment of \$3.2 million of accrued interest related to the old first lien credit facility pursuant to the Plan.

(d) Reflects the incurrence of indebtedness under the Second Lien Credit Facility, which has an aggregate principal amount of \$252.5 million pursuant to the Plan, and is net of deferred financing costs of \$2.2 million.

(e) Liabilities subject to compromise were settled as follows in accordance with the Plan:

Liabilities subject to compromise (“LSTC”):	
7.75% and 9.25% Senior Notes, net of debt discount and deferred financing costs	\$648,612
Old second lien credit facility, net of debt discount and deferred financing costs	234,451
Accrued interest related to the Senior Notes and old second lien credit facility	32,563
LSTC of Predecessor	915,626
Issuance of Second Lien Credit Facility	(252,500)
Payment of accrued interest related to the old second lien credit facility	(2,375)
Second Lien Credit Facility deferred financing costs reinstated	316
Gain on the settlement of LSTC	\$661,067

(f) Reflects the cancellation of our Predecessor’s general partner’s interest, preferred limited partners’ interests, common limited partner interests and elimination of accumulated other comprehensive income pursuant to the Plan.

(g) Reflects the establishment of member’s equity following the consummation of the transactions pursuant to the Plan. Pursuant to our amended and restated limited liability company agreement, the holder of the Series A Preferred Share is entitled to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members’ equity), subject to dilution if certain catch-up contributions are not made with respect to future equity issuances.

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Reflects the cumulative impact of reorganization adjustments as discussed above:	
Gain on liabilities subject to compromise	\$661,067
Cancellation of Predecessor's capital interests	(279,711)
Net cash, deferring financing costs, and other adjustments	(19,877)
Total impact of reorganization adjustments	\$361,479
Allocation of total impact of reorganization adjustments to establish members' equity:	
Series A Preferred member's interest	\$7,230
Common shareholders' interests	\$354,249

Fresh Start Accounting Adjustments:

- (a) Reflects the adjustment of certain accounts receivable to their estimated fair value.
- (b) Reflects the following adjustments made to record property, plant and equipment, net at its estimated fair value. The fair values of proved natural gas and oil properties and support equipment and other were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair value of unproved properties was the result of the excess reorganization value over the fair value of identified tangible and intangible assets and represents the value of our probable and possible drilling locations within our various acreage positions.

	Fresh Start		
	Predecessor	Adjustments	Successor
Natural gas and oil properties:			
Proved properties	\$3,620,371	\$(2,950,427)	\$669,944
Unproved properties	213,047	(138,613)	74,434
Support equipment and other	131,587	(117,760)	13,827
Total natural gas and oil properties	3,965,005	(3,206,800)	758,205
Accumulated depreciation, depletion and amortization	(2,810,139)	2,810,139	—
Property, plant and equipment, net	\$1,154,866	\$(396,661)	\$758,205

- (c) Reflects the adjustment made to record the elimination of the Predecessor's goodwill.
- (d) Reflects the adjustment of certain accrued liabilities to their estimated fair value.
- (e) Reflects the adjustment made to record asset retirement obligations at fair value. The fair value of asset retirement obligations was measured using a discounted cash flow model based on our historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements. We used the discount rate consistent with the rate used for our gas and oil production business.
- (f) Reflects the adjustment of certain other long-term liabilities to their estimated fair value.
- (g) Reflects the adjustment to members' equity following the fresh start accounting adjustments. Pursuant to our LLC Agreement, the holder of the Series A Preferred Share is entitled to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity), subject to dilution if certain catch-up contributions are not made with respect to future equity issuances.

Reflects the cumulative impact of fresh start adjustments as discussed above:

\$(396,661)

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Property, plant, and equipment, net fair value adjustment	
Elimination of Predecessor's goodwill	(13,639)
Accounts receivable fair value adjustment	(56)
Other liabilities fair value adjustment	52
Accrued liabilities fair value adjustment	2,774
Asset retirement fair value adjustment	72,067
Total impact of fresh start adjustments	\$(335,463)
Allocation of total impact of fresh start adjustments to members' equity:	
Series A Preferred member's interest	\$(6,709)
Common shareholders' interest	\$(328,754)

Reorganization Items, net:

Incremental costs incurred as a result of the Chapter 11 Filings, net gain on settlement of liabilities subject to compromise and reorganization adjustments, and net impact of fresh start adjustments are classified as “Reorganization items, net” in the Predecessor’s consolidated statement of operations. The following table summarizes the reorganization items:

Professional fees and other	\$(33,065)
Accelerated amortization of deferred financing costs	(9,565)
Net gain on reorganization adjustments	361,479
Net loss on fresh start adjustments	(335,463)
Total reorganization items, net	\$(16,614)

NOTE 4 – ACQUISITIONS

Rangely Acquisition

On June 30, 2014, our Predecessor completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado from Merit Management Partners I, L.P., Merit Energy Partners III, L.P. and Merit Energy Company, LLC (collectively, “Merit Energy”) for \$408.9 million in cash, net of purchase price adjustments (the “Rangely Acquisition”). The purchase price was funded through borrowings under our Predecessor’s revolving credit facility, the issuance of an additional \$100.0 million of our Predecessor’s 7.75% senior notes (“7.75% Senior Notes”) and the issuance of 15,525,000 of our Predecessor’s common limited partner units. The Rangely Acquisition had an effective date of April 1, 2014. Our Predecessor’s consolidated financial statements reflected the operating results of the acquired business commencing June 30, 2014 with the transaction closing.

Our Predecessor accounted for this transaction under the acquisition method of accounting. Accordingly, our Predecessor evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. In conjunction with the issuance of common limited partner units associated with the acquisition, our Predecessor recorded \$11.6 million of transaction fees, which were included with our Predecessor’s common limited partners’ interests for the year ended December 31, 2014 on our Predecessor’s consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

The following table presents the values assigned to the assets acquired and liabilities assumed in the acquisition, based on their estimated fair values at the date of the acquisition (in thousands):

Assets:	
Prepaid expenses and other	\$4,041
Property, plant and equipment	405,416
Other assets, net	2,888
Total assets acquired	\$412,345
Liabilities:	
Accrued liabilities	2,117

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Asset retirement obligation	1,305
Total liabilities assumed	3,422
Net assets acquired	\$408,923

Other Acquisitions:

Arkoma Acquisition

On June 5, 2015, our Predecessor completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for \$31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). Our Predecessor funded the purchase price through the issuance of 6,500,000 common limited partner units. The Arkoma Acquisition had an effective date of January 1, 2015. Our Predecessor accounted for the Arkoma Acquisition as a transaction between entities under common control (see Note 2).

Eagle Ford Acquisition

On November 5, 2014, our Predecessor and AGP completed an acquisition of oil and natural gas liquid interests in the Eagle Ford Shale in Atascosa County, Texas from Cima Resources, LLC and Cinco Resources, Inc. (together "Cinco") for \$342.0 million, net of purchase price adjustments (the "Eagle Ford Acquisition"). Our Predecessor paid \$183.1 million in cash and \$19.9 million was

paid by AGP at closing, and \$139.0 million was to be paid in four quarterly installments beginning December 31, 2014. On December 31, 2014, AGP made its first installment payment of \$35.0 million related to its Eagle Ford Acquisition. Prior to the March 31, 2015 installment, our Predecessor, AGP and Cinco amended the purchase and sale agreement to alter the timing and amount of the quarterly payments beginning with the March 31, 2015 payment and ending December 31, 2015, with no change to the overall purchase price. On March 31, 2015, AGP paid \$28.3 million and our Predecessor issued \$20.0 million of its Class D Preferred Units (see Note 13) to satisfy the second installment related to the Eagle Ford Acquisition. On June 30, 2015, AGP paid \$16.0 million and our Predecessor paid \$0.6 million to satisfy the third installment related to the Eagle Ford Acquisition. On July 8, 2015, AGP sold to our Predecessor, for a purchase price of \$1.4 million, AGP's interest in a portion of the acreage AGP acquired in the Eagle Ford Acquisition. In September 2015, our Predecessor agreed with AGP to have AGP transfer its remaining \$36.3 million of deferred purchase obligation, along with the related undeveloped natural gas and oil properties, to our Predecessor. On October 1, 2015 our Predecessor paid \$17.5 million to satisfy the fourth installment related to the Eagle Ford Acquisition. On December 31, 2015 our Predecessor paid \$21.6 million to satisfy the final installment related to the Eagle Ford Acquisition. Our Predecessor's issuance of Class D Preferred Units in March 2015 represented a non-cash transaction for statement of cash flow purposes during the year ended December 31, 2015.

GeoMet Acquisition

On May 12, 2014, our Predecessor completed the acquisition of certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for \$97.9 million in cash, net of purchase price adjustments, with an effective date of January 1, 2014. The assets included coal-bed methane producing natural gas assets in West Virginia and Virginia.

NOTE 5 – PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment at the dates indicated (in thousands):

	Successor December 31,	Predecessor December 31,
	2016	2015
Natural gas and oil properties:		
Proved properties	\$ 717,839	\$ 3,585,839
Unproved properties	74,434	213,047
Support equipment and other	14,180	130,691
Total natural gas and oil properties	806,453	3,929,577
Less – accumulated depreciation, depletion and amortization	(21,730)	(2,737,966)
	\$ 784,723	\$ 1,191,611

During the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014, we recognized \$0.3 million, \$18.7 million, \$22.6 million and \$25.0 million, respectively, of non-cash investing activities capital expenditures, which was reflected within the changes in accounts payable and accrued liabilities on our consolidated statements of cash flows. During the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, we recognized \$31.0 million and \$7.7 million, respectively, of non-cash investing activities capital expenditures, which was reflected within the changes to adjustments to reconcile net loss to net cash provided by operating activities – other (income) loss on our consolidated

statements of cash flows.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate we will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. During the Predecessor year ended December 31, 2015, our Predecessor recognized \$6.6 million of asset impairments related to its unproved gas and oil properties within property, plant and equipment, net on the consolidated balance sheet, primarily for its unproved acreage in the New Albany Shale, which was impaired due to expiring acreage and no intention to pursue development. There were no impairments of unproved gas and oil properties for the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 and year ended December 31, 2014.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Asset impairments and offsetting hedge gains, if any, are included in asset impairment expense in our consolidated statement of operations. For the Predecessor year ended December 31, 2015, our Predecessor recognized \$960.0 million of asset impairment related to proved oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia,

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Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, net of \$85.8 million of future hedge gains reclassified from accumulated other comprehensive income. During the Predecessor year ended December 31, 2014, our Predecessor recognized \$555.7 million of asset impairment related to proved oil and gas properties within property, plant and equipment, net on its consolidated balance sheet for its Appalachian and mid-continent operations which were impaired due to lower forecasted commodity prices, net of \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income. No impairment of proved gas and oil properties was recognized for the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016.

During the year ended December 31, 2014, we recognized \$1.9 million of loss on asset sales and disposal on our consolidated statement of operations related to our Predecessor's sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

The estimated liability for asset retirement obligations was based on our historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements. The liability was discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. We have no assets legally restricted for purposes of settling asset retirement obligations. Except for our gas and oil properties, we determined that there were no other material retirement obligations associated with tangible long-lived assets.

We proportionately consolidate our ownership interest of the asset retirement obligations of our Drilling Partnerships. At December 31, 2016, the Drilling Partnerships had \$18.5 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of our proportional interest in such liabilities. Under the terms of the respective partnership agreements, we maintain the right to retain a portion or all of the distributions to the limited partners of our Drilling Partnerships to cover the limited partners' share of the plugging and abandonment costs up to a specified amount per month. As of December 31, 2016, we have withheld \$1.8 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. Our historical practice and continued intention is to retain distributions from the limited partners as the wells within each Drilling Partnership near the end of their useful life. On a partnership-by-partnership basis, we assess our right to withhold amounts related to plugging and abandonment costs based on several factors including commodity price trends, the natural decline in the production of the wells, and current and future costs. Generally, our intention is to retain distributions from the limited partners as the fair value of the future cash flows of the limited partners' interest approaches the fair value of the future plugging and abandonment cost. Upon our decision to retain all future distributions to the limited partners of our Drilling Partnerships, we will assume the related asset retirement obligations of the limited partners.

A reconciliation of our liability for well plugging and abandonment costs for the periods indicated is as follows (in thousands):

Successor Period from	Predecessor Period from	Year Ended	Year Ended
September 1,	January 1,	December 31,	December 31,

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	2016 through December 31,	2016 through August 31,	2015	2014
Asset retirement obligations, beginning of period	\$ 58,868	2016 \$ 113,740	\$ 107,950	\$ 91,179
Liabilities incurred	14,671	12,458	2,070	3,512
Adjustment to liability due to acquisitions (Note 4)	—	—	—	6,997
Liabilities settled	(399) 139	(2,591) (1,664
Accretion expense	2,207	4,598	6,311	5,747
Revisions	—	—	—	2,179
Asset retirement obligations, end of period	\$ 75,347	\$ 130,935	\$ 113,740	\$ 107,950

The above accretion expense was included in depreciation, depletion and amortization our consolidated statements of operations. The above liabilities incurred in the Successor and Predecessor periods of 2016 are primarily additions to our asset retirement obligations due to the consolidation of some of our Drilling Partnerships during the respective periods.

NOTE 7 – DEBT

Total debt consists of the following at the dates indicated (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
First Lien Credit Facility	\$435,809	\$—
Second Lien Credit Facility	261,022	—
Old First Lien Credit Facility	—	592,000
Old Second Lien Term Loan	—	243,783
7.75 % Senior Notes – due 2021	—	374,619
9.25 % Senior Notes – due 2021	—	324,080
Deferred financing costs, net of accumulated amortization of \$172 and \$10,915, respectively	(2,021)	(31,055)
Total debt, net	694,810	1,503,427
Less current maturities	(694,810)	—
Total long-term debt, net	\$—	\$1,503,427

Cash Interest. Total cash payments for interest by us for the Successor period September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014, were \$7.5 million, \$53.7 million, \$98.5 million and \$58.7 million, respectively.

Deferred financing costs and related amortization. Deferred financing costs related to other debt arrangements (non-revolving credit facility arrangements) are recorded at cost, amortized over the term of the respective debt agreements, and are presented net of accumulated amortization as a direct deduction from the associated debt obligation on our consolidated balance sheets. For the Successor period September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 2015 and 2014, amortization expense of non-revolving credit facility deferred financing costs was \$0.2 million, \$3.7 million, \$4.4 million and \$1.9 million, respectively, which was recorded within interest expense on our consolidated statements of operations.

First Lien Credit Facility

On September 1, 2016, we entered into a \$440 million First Lien Credit Facility agreement with Wells Fargo Bank, National Association (“Wells Fargo”), as administrative agent, and the lenders party thereto. A summary of the key provisions of the First Lien Credit Facility is as follows:

- Borrowing base of a \$410 million conforming reserve based tranche plus a \$30 million non-conforming tranche.
- Provides for the issuance of letters of credit, which reduce borrowing capacity.
- The non-conforming tranche matures on May 1, 2017 and the conforming reserve-based tranche matures on August 23, 2019.
- Borrowing base will be redetermined semi-annually, with additional interim re-determinations permitted under certain circumstances. The first scheduled borrowing base redetermination shall occur on May 1, 2017; provided, that a super majority of the lenders may elect, in certain circumstances, to seek an interim redetermination of the

borrowing base prior to May 1, 2017.

• Obligations are secured by mortgages on substantially all of our oil and gas properties and first priority security interests in substantially all of our assets and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

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Borrowings bear interest at our election at either LIBOR plus an applicable margin between 3.00% and 4.00% per annum or the “alternate base rate” plus an applicable margin between 2.00% and 3.00% per annum, which fluctuates based on utilization. We are also required to pay a fee of 0.50% per annum on the unused portion of the borrowing base. At December 31, 2016, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 5.0%.

Contains covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of our assets.

Requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017.

Required us to maintain certain financial ratios (which will use an annualized EBITDA measurement for periods prior to June 30, 2017):

Total Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 5.00 to 1.00;

Current assets to current liabilities (each as defined in the First Lien Credit Facility) of not less than 1.00 to 1.00;

First Lien Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 3.50 to 1.00; and

EBITDA to Interest Expense (each as defined in the First Lien Credit Facility) of not less than 2.50 to 1.00.

Certain of the above financial ratios are expected to be amended. See “Credit Facility Amendment” section below for further description.

Second Lien Credit Facility

On September 1, 2016, we entered into an amended and restated second lien credit agreement with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto (the “Second Lien Credit Facility”) for an aggregate principal amount of \$252.5 million maturing on February 23, 2020. A summary of the key provisions of the Second Lien Credit Facility is as follows:

Until May 1, 2017, interest will be payable at a rate of 2% in cash plus paid-in-kind interest at a rate equal to the Adjusted LIBO Rate (as defined in the Second Lien Credit Facility) plus 9% per annum. During the subsequent 15-month period, cash and paid-in-kind interest will vary based on a pricing grid tied to our leverage ratio under the First Lien Credit Facility. After such 15-month period, interest will accrue at a rate equal to the Adjusted LIBO Rate plus 9% per annum and will be payable in cash.

All prepayments are subject to the following premiums, plus accrued and unpaid interest:

4.5% of the principal amount prepaid for prepayments prior to February 23, 2017;

2.25% of the principal amount prepaid for prepayments on or after February 23, 2017 and prior to February 23, 2018; and

no premium for prepayments on or after February 23, 2018.

Obligations are secured on a second priority basis by security interests in the same collateral securing the First Lien Credit Facility and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

- Contains covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions, engage in other business activities, and other covenants substantially similar to those in the First Lien Credit Facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables.

Requires us to maintain certain financial ratios (the financial ratios will use an annualized EBITDA measurement for periods prior to June 30, 2017):

EBITDA to Interest Expense (each as defined in the Second Lien Credit Facility) of not less than 2.50 to 1.00;

Total Leverage Ratio (as defined in the Second Lien Credit Facility) of no greater than 5.5 to 1.0 prior to December 31, 2017 and no greater than 5.0 to 1.0 thereafter; and

Current assets to current liabilities (each as defined in the Second Lien Credit Facility) of not less than 1.0 to 1.0.

Credit Facilities Amendment

As described in Note 2, we are not in compliance with certain of the financial covenants under our Credit Facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. In addition to the \$30 million of indebtedness due on May 1, 2017, we classified the remaining \$666.8 million of outstanding indebtedness under our credit facilities as a current liability, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. In total, we have \$694.8 million of outstanding indebtedness under our credit facilities, which is net of \$2 million of deferred financing costs, as current portion of long term debt, net within our consolidated balance sheet as of December 31, 2016.

On April 19, 2017, we expect to enter into an amendment to the First Lien Facility. Pursuant to the amendment, certain of the financial ratio covenants will be revised upwards. Specifically, beginning December 31, 2017, we are required to maintain a ratio of Total Debt to EBITDA (each as defined in the First Lien Facility) of not more than 5.50 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 5.00 to 1.00 thereafter. We are also required, beginning December 31, 2017, to maintain a ratio of First Lien Debt (as defined in the First Lien Facility) to EBITDA of not more than 4.00 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 3.50 to 1.00 thereafter.

In addition to the amendments to the financial ratio covenants, the First Lien lenders will waive certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a “going concern” qualification. The First Lien lenders’ waivers are subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Facility.

The First Lien amendment will confirm the conforming and non-conforming tranches of the borrowing base at \$410 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$330 million by August 31, 2017 and to \$190 million by October 1, 2017 (subject to extension at the administrative agent’s option to October 31, 2017). Similarly, the non-conforming tranche of the borrowing base will be required to be reduced to \$10 million by November 1, 2017. In addition, we will be required to use excess asset sale proceeds (after application in accordance with the existing terms of the First Lien Facility) to repay outstanding borrowings and reduce the applicable borrowing base to the required level.

Unless we are able to obtain an amendment or waiver, the lenders under our Second Lien Facility may declare a default with respect to our failure to comply with financial covenants and deliver audited financial statements without

a going concern qualification. However, pursuant to the intercreditor agreement, the lenders under the Second Lien Facility are restricted in their ability to pursue remedies for 180 days from any such notice of default. As of the date hereof, the lenders under the Second Lien Facility have not yet given us notice of any default.

Old First Lien Credit Facility

Our Predecessor was party to a Second Amended and Restated Credit Agreement, dated as of July 31, 2013 by and among our Predecessor, the lenders from time to time party thereto, and Wells Fargo, as administrative agent, as amended, supplemented or modified from time to time (the “Old First Lien Credit Facility”), which provided for a senior secured revolving credit facility with a maximum borrowing base of \$1.5 billion and was scheduled to mature in July 2018.

Pursuant to the Restructuring Support Agreement, our Predecessor completed the sale of substantially all its commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay \$233.5 million of borrowings outstanding under the Old First Lien Credit Facility. For the Predecessor period January 1, 2016 through August 31, 2016, the weighted average interest rate on outstanding borrowings under the Old First Lien Credit Facility was 5.5%. Pursuant to the Plan, the Old First Lien Credit Facility was replaced by the First Lien Credit Facility (see Note 1).

Old Second Lien Term Loan

Our Predecessor was party to a Second Lien Credit Agreement, dated as of February 23, 2015 by and among our Predecessor, the lenders from time to time party thereto, and Wilmington Trust, National Association, as administrative agent, as amended, supplemented or modified from time to time (the “Old Second Lien Term Loan”), which provided for a second lien term loan in an original principal amount of \$250.0 million.

For the Predecessor period January 1, 2016 through August 31, 2016, the weighted average interest rate on outstanding borrowings under the Old Second Lien Term Loan was 10.0%. Pursuant to the Plan, the Old Second Lien Term Loan was replaced by the Second Lien Facility (see Note 1).

Senior Notes

In January and February 2016, our Predecessor executed transactions to repurchase \$20.3 million of our Predecessor’s 7.75% Senior Notes and \$12.1 million of our Predecessor’s 9.25% Senior Notes for \$5.5 million, which included \$0.6 million of interest. As a result of these transactions, our Predecessor recognized \$26.5 million as gain on early extinguishment of debt, net of accelerated amortization of deferred financing costs of \$0.9 million, in the consolidated statement of operations for the Predecessor period from January 1, 2016 through August 31, 2016.

Pursuant to the Plan, Holders of the Notes, in exchange for 100% of the \$668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of the common equity interests of us (see Note 1).

The aggregate amount of our debt maturities is as follows (in thousands):

Years Ended December 31:	
2017	\$696,831
2018	—
2019	—
2020	—
2021	—
Thereafter	—
Total principal maturities	696,831
Deferred financing costs, net of accumulated	
amortization	(2,021)
Total debt	\$694,810

NOTE 8 – DERIVATIVE INSTRUMENTS

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price risk management activities. We enter into financial instruments to hedge forecasted commodity sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under commodity-based swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. To manage the risk of regional commodity price differences,

we occasionally enter into basis swaps. Basis swaps are contractual arrangements that guarantee a price differential for a commodity from a specified delivery point price and the comparable national exchange price. For natural gas basis swaps, which have negative differentials to the New York Mercantile Stock Exchange (“NYMEX”), we receive or pay a payment from the counterparty if the price differential to NYMEX is greater or less than the stated terms of the contract. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right, but not the obligation, to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged.

On January 1, 2015, our Predecessor discontinued the use of hedge accounting for its qualified commodity derivatives. As such, changes in fair value of these derivatives after December 31, 2014 were recognized immediately within gain (loss) on mark-to-market derivatives in our Predecessor’s consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners’ capital (deficit) on the Predecessor’s consolidated balance sheet, were being reclassified to the Predecessor’s consolidated statements of operations at the time the originally hedged physical transactions settled.

We enter into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on our consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on our consolidated balance sheets as the initial value of the options. We recorded net derivative liabilities of \$49.4 million and net derivative assets of \$357.7 million on our consolidated balance sheets as of December 31, 2016 and 2015, respectively.

Pursuant to the Restructuring Support Agreement, our Predecessor completed the sale of substantially all of its commodity hedge positions on July 25, 2016 and July 26, 2016 for \$235.3 million, net of \$8.2 million in hedge monetization fees, and used the proceeds to repay \$233.5 million of borrowings outstanding under the Old First Lien Credit Facility.

The following table summarizes the commodity derivative activity and presentation in our consolidated statements of operations for the periods indicated (in thousands):

	Successor	Predecessor Period from	
		January 1, Period from	Year Ended
	September 1, 2016 through	2016 through	December 31, 2015
	December 31, 2016	August 31, 2016	December 31, 2015
Portion of settlements associated with gains (losses) previously recognized within accumulated other comprehensive income, net of prior year offsets ⁽¹⁾⁽²⁾	\$ —	\$ 10,758	\$ 86,328
Portion of settlements attributable to subsequent mark to market gains (losses) ⁽²⁾	(1,825)	89,041	92,732
Total cash settlements on commodity derivative contracts ⁽²⁾	\$ (1,825)	\$ 99,799	\$ 179,060
Gains (losses) recognized on cash settlement ⁽³⁾	\$ (532)	\$(16,570)	\$ 40,480
Gains (losses) recognized on open derivative contracts ⁽³⁾	(43,360)	(7,346)	226,743
Gains (losses) on mark-to-market derivatives	\$ (43,892)	\$(23,916)	\$ 267,223

(1) Recognized in gas and oil production revenue.

(2) For the Predecessor period from January 1, 2016 through August 31, 2016, excludes the effects of the \$235.3 million, net of \$8.2 million in hedge monetization fees, paid directly to the First Lien Credit Facility lenders upon the sale of substantially all of our Predecessor's commodity hedge positions on July 25, 2016 and July 26, 2016.

(3) Recognized in gain (loss) on mark-to-market derivatives.

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The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities included on our consolidated balance sheets for the periods indicated (in thousands):

	Gross Amounts	Gross Amounts	Net Amount
Successor Offsetting Derivatives as of December 31, 2016			
Current portion of derivative assets	Recognized \$ 7	Offset \$ (7)	Presented \$—
Long-term portion of derivative assets	819	(819)	—
Total derivative assets	\$ 826	\$ (826)	\$—
Current portion of derivative liabilities	\$ (34,806)	\$ 7	\$(34,799)
Long-term portion of derivative liabilities	(15,434)	819	(14,615)
Total derivative liabilities	\$ (50,240)	\$ 826	\$(49,414)
Predecessor Offsetting Derivatives as of December 31, 2015			
Current portion of derivative assets	\$ 159,460	\$ —	\$ 159,460
Long-term portion of derivative assets	198,262	—	198,262
Total derivative assets	\$ 357,722	\$ —	\$ 357,722
Current portion of derivative liabilities	\$ —	\$ —	\$—
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	\$ —	\$ —	\$—

At December 31, 2016, we had the following commodity derivatives instruments:

Type	Period Ending	Production Volumes ⁽¹⁾	Average Fixed Price ⁽¹⁾	Fair Value		Total Type (in thousands)
				Liability (in thousands) ⁽²⁾		
Natural Gas – Fixed Price Swaps	2017	51,679,700	\$3.140	\$ (24,579)		
	2018	47,559,300	\$2.959	\$ (8,079)		
						\$(32,658)
Crude Oil – Fixed Price Swaps	2017	1,188,700	\$46.971	\$ (10,220)		
	2018	1,011,100	\$49.544	\$ (6,536)		
						\$(16,756)
				Total net liabilities		\$(49,414)

- (1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.
- (2) Fair value for natural gas fixed price swaps are based on forward NYMEX natural gas prices, as applicable. Fair value of crude oil fixed price swaps are based on forward West Texas Intermediate (“WTI”) index crude oil prices, as applicable.

Secured Hedge Facility

At December 31, 2016, we have a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our First Lien Credit Facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as the ultimate general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership’s ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

An event of default occurred under the secured hedging facility agreement upon our filing of voluntary petitions for relief under Chapter 11. The lenders under the secured hedge facility agreed to forbear from exercising remedies in respect of such event of default while the Chapter 11 Filings were pending and, upon occurrence of the effective date of the Plan contemplated by the Restructuring Support Agreement, such event of default is no longer be deemed to exist or to continue under the secured hedge facility.

In addition, it will be an event of default under our First Lien Credit Facility if we, as the ultimate general partner of the Drilling Partnerships, breach an obligation governed by the secured hedge facility, and the effect of such breach is to cause amounts owing under swap agreements governed by the secured hedge facility to become immediately due and payable.

NOTE 9 – FAIR VALUE OF FINANCIAL INSTRUMENTS

We have established a hierarchy to measure our financial instruments at fair value, which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect our own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 – Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 – Unobservable inputs that reflect the entity’s own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We use a market approach fair value methodology to value the assets and liabilities for our outstanding derivative instruments (see Note 8). We manage and report derivative assets and liabilities on the basis of our exposure to market risks and credit risks by counterparty. Commodity derivative instruments are valued based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 assets and liabilities within the same class of nature and risk. These derivative values were calculated by utilizing commodity indices, quoted prices for futures and options contracts traded on open markets that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Information for financial instruments measured at fair value at December 31, 2016 and 2015 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
Successor Derivatives, Fair Value, as of December 31, 2016				
Assets, gross				
Commodity swaps	\$ —	\$ 826	\$ —	\$ 826
Total derivative assets, gross	—	826	—	826

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Liabilities, gross				
Commodity swaps	—	(50,240)	—	(50,240)
Total derivative liabilities, gross	—	(50,240)	—	(50,240)
Total derivatives, fair value, net	\$	—	\$	(49,414)

Predecessor Derivatives, Fair Value, as of December 31, 2015	Level		Level	
	1	Level 2	3	Total
Assets, gross				
Commodity swaps	\$	—	\$	355,329
Commodity puts		—		2,393
Total derivatives, fair value, net	\$	—	\$	357,722

Other Financial Instruments

Our other current assets and liabilities on our consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair value of our long-term debt at December 31, 2016, which consists of our First Lien Credit Facility and Second Lien Credit Facility, approximated carrying value of \$696.8 million. At December 31, 2016, the carrying value of outstanding borrowings under our First Lien Credit Facility, which bears interest at variable interest rates, approximated estimated fair value. The estimated fair value of our Second Lien Credit Facility was based upon the market approach and calculated using yields of our Second Lien Credit Facility as provided by financial institutions and thus were categorized as Level 3 values.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

We estimated the fair values of natural gas and oil properties transferred to our Predecessor and us upon consolidation of certain Drilling Partnerships in separate transactions (see Note 10) based on discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, our future operating and development costs of the assets, the respective natural gas, oil and natural gas liquids forward price curves and estimated salvage values using our historical experience and external estimates of recovery values. We used a discount rate of 10%, which is consistent with our and our Predecessor's weighted average cost of capital. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

We estimated the fair value of asset retirement obligations assumed by us and our Predecessor in separate transactions upon consolidation of certain Drilling Partnerships (see Note 6) based on discounted cash flow projections using our historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future considering inflation rates, federal and state regulatory requirements, and a discount rate consistent with that used in valuing the related natural gas and oil properties acquired. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

We estimated the fair value of our enterprise value and reorganizational value of assets and liabilities upon our emergence from bankruptcy through fresh-start accounting (see Note 3) utilizing the discounted cash flow method for both our gas and oil production business and our partnership management business based on the financial projections in our disclosure statement. The resulting fair value of our equity was used to value shares issued under our incentive plan. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

During the year ended December 31, 2014, our Predecessor completed the Eagle Ford, Rangely and GeoMet acquisitions (see Note 4). The fair value measurements of assets acquired and liabilities assumed for these acquisitions were based on inputs that were not observable in the market and therefore represented Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were measured under our Predecessor's existing methodology for recognizing an estimated liability for the plugging and abandonment of its gas and oil wells (see Note 6). These inputs required significant judgments and estimates by our Predecessor's management at the time of the valuations, which were finalized in 2015.

NOTE 10 – CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with ATLS. Except for our named executive officers, we do not directly employ any persons to manage or operate our business. These functions are provided by employees of ATLS and/or its affiliates. As of December 31,

2016 and 2015, we had a \$3.3 million receivable and a \$1.3 million payable, respectively, from/to ATLS related to the timing of funding cash accounts related to general and administrative expenses, such as payroll and benefits, which was recorded in advances to/from affiliates in the consolidated balance sheets.

Relationship with Drilling Partnerships. We conduct certain activities through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. We serve as general partner and operator of the Drilling Partnerships and assume customary rights and obligations for the Drilling Partnerships. As the general partner, we are liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the Drilling Partnerships if we breach our responsibilities with respect to the operations of the Drilling Partnerships. We are entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership's revenue and costs and expenses according to the respective partnership agreements.

In March 2016, our Predecessor transferred \$36.7 million of investor capital raised and \$13.3 million of accrued well drilling and completion costs incurred by our Predecessor to the Atlas Eagle Ford 2015 L.P. private drilling partnership for activities directly related to their program. In June 2016, our Predecessor transferred \$5.2 million of funds to certain of the Drilling Partnerships that were projected to make monthly or quarterly distributions to their limited partners over the next several months and/or quarters to ensure accessible distribution funding coverage in accordance with the respective Drilling Partnerships' operations and partnership

agreements in the event our Predecessor experienced a prolonged restructuring period as our Predecessor performed all administrative and management functions for the Drilling Partnerships. On July 26, 2016, we adopted certain amendments to the Drilling Partnerships' partnership agreements, in accordance with our ability to amend the Drilling Partnerships' partnership agreements to cure an ambiguity in or correct or supplement any provision of the Drilling Partnerships' partnership agreements as may be inconsistent with any other provision, to provide that bankruptcy and insolvency events, such as the Chapter 11 Filings, with respect to the managing general partner will not cause the managing general partner to cease to serve as the managing general partner of the Drilling Partnerships nor cause the termination of the Drilling Partnerships.

We intend to continue to fund the Drilling Partnerships' operations and obligations, as necessary, until they are liquidated. During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor recognized a \$10.9 million provision for losses on Drilling Partnership receivables related to the write down of certain receivables to their estimated net realizable values, which was recorded within general and administrative expenses on the consolidated statement of operations. During the Predecessor period from January 1, 2016 to August 31, 2016, our Predecessor recorded \$7.2 million and \$12.4 million of gas and oil properties and asset retirement obligations, respectively, transferred to our Predecessor as a result of certain Drilling Partnership consolidations. The gas and oil properties and asset retirement obligations were recorded at their fair values on the respective dates of the Drilling Partnerships' consolidation and transfer to our Predecessor (see Note 9) and resulted in a non-cash loss of \$6.1 million, net of consolidation and transfer adjustments, for the Predecessor period from January 1, 2016 through August 31, 2016, which was recorded in other income/(loss) in our Predecessor's consolidated statement of operations.

On October 24, 2016, the Board of Directors of our subsidiary, Atlas Resources, LLC, approved our acquisition of properties in exchange for assuming all liabilities in connection with the consolidation of certain of our Drilling Partnerships. These acquisitions had an effective date of October 1, 2016. We recorded \$31.0 million and \$14.7 million of gas and oil properties and asset retirement obligations, respectively, which resulted in a non-cash gain of \$22.4 million after other consolidation and transfer adjustments, for the Successor period from September 1, 2016 through December 31, 2016, which was recorded in other income/(loss) in our consolidated statement of operations.

As of December 31, 2016 and 2015, we had trade receivables of \$0.3 million and a \$6.6 million, respectively, from certain of the Drilling Partnerships, which were recorded in accounts receivable in the consolidated balance sheets. As of December 31, 2016 and 2015, we had trade payables of \$5.6 million and \$3.0 million, respectively, to certain of the Drilling Partnerships, which were recorded in accounts payable in the consolidated balance sheets.

Relationship with AGP. At the direction of ATLS, we charge direct costs, such as salaries and wages, and allocate indirect costs, such as rent and other general and administrative costs, to AGP based on the number of ATLS employees who devoted time to AGP's activities. In addition, Anthem, acted as dealer manager for AGP's private placement offering, which was completed in June 2015. As the dealer manager, Anthem received compensation from AGP equal to a maximum of 12% of the gross proceeds of the private placement offering as selling commissions, marketing efforts, and other issuance costs.

Anthem is currently acting as the dealer manager for AGP's issuance and sale in a continuous offering of up to a maximum agreement amount of 100,000,000 common units representing limited partner interests in AGP as further described in AGP's registration statement on Form S-1 (File No. 333-207537). AGP will pay Anthem (1) compensation equal to 3.00% of the gross proceeds of the offering (Anthem may reallocate up to 1.50% of gross offering proceeds it receives as dealer manager fees to participating broker-dealers, but expects to reallocate 1.25% of gross offering proceeds to participating broker-dealers); (2) 7.00% and 3.00% of aggregate gross proceeds from the sale of Class A common units and Class T common units, respectively, as sales commissions; (3) with respect to Class T common units, a distribution and unitholder servicing fee in the aggregate amount of 4.00% of the gross proceeds from the sale of Class T common units, which distribution and unitholder servicing fee will be withheld from cash

distributions otherwise payable to the purchasers of Class T common units at a rate of \$0.025 per quarter per unit. On November 2, 2016, AGP decided to temporarily suspend its current primary offering efforts in light of new regulations and the challenging fund raising environment until such time as market participants have had an opportunity to ascertain the impact of such issues.

As of December 31, 2016 and 2015, we had a \$0.8 million receivable and \$8.7 million payable, respectively, from/to AGP related to AGP's direct costs, indirect cost allocation and dealer manager costs, which was recorded in advances to/from affiliates in the consolidated balance sheets.

Other Relationships. We have other related party transactions with regard to certain funds advised and sub-advised by GSO Capital Partners LP and its affiliates ("GSO") as GSO funds are majority lenders under our Second Lien Credit Facility and GSO funds hold an excess of ten-percent of our common shares.

NOTE 11 – COMMITMENTS AND CONTINGENCIES

Rental Commitments

We lease office space and equipment under leases with varying expiration dates. For the Successor period September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 2015 and 2014, rental expense was \$3.5 million, \$7.8 million, \$15.7 million and \$17.0 million, respectively.

Future minimum rental commitments for the next five years are as follows (in thousands):

Years Ended December 31,	
2017	\$3,781
2018	3,460
2019	1,830
2020	1,651
2021	1,206
Thereafter	668
	\$12,596

Drilling Partnership Commitments

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally, for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of December 31, 2016, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

While our historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction

of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production revenue, subject to a limitation of the cumulative subordination previously recognized. For the Successor period September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014, \$0.8 million, \$1.0 million, \$1.7 million and \$5.3 million, respectively, of our gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses.

Firm Transportation and Gas Gathering Commitments We have certain agreements for firm transportation and gas gathering obligations. Firm transportation agreements provide for transportation capacity rights for specified volumes per day on various pipeline systems. The contracts require us to pay transportation demand charges regardless of the amount of the pipeline capacity we use. Gas gathering agreements require us to make certain minimum payments regardless of the volume of natural gas production. Our firm transportation and gas gathering agreements expire at various dates through 2024. Fixed and determinable portions of our minimum aggregate future payments under these firm transportation and gathering obligations for the next five years are as follows (in thousands):

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Years Ended December 31,	
2017	\$5,258
2018	4,476
2019	3,876
2020	1,830
2021	1,227
Thereafter	1,493
	\$18,160

As of December 31, 2016, we are committed to expend approximately \$20.4 million, principally on drilling and completion expenditures.

Environmental Matters

We and our subsidiaries are subject to various federal, state and local laws and regulations relating to the protection of the environment. We have established procedures for the ongoing evaluation of our and our subsidiaries' operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. We and our subsidiaries maintain insurance which may cover in whole or in part certain environmental expenditures. We and our subsidiaries had no environmental matters requiring specific disclosure or requiring the recognition of a liability as of December 31, 2016 and 2015.

Legal Proceedings

We are party to various routine legal proceedings arising out of the ordinary course of our business. We believe that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations.

NOTE 12 – INCOME TAXES

We account for income taxes under the asset and liability method pursuant to prevailing accounting literature. Under such literature, deferred income taxes are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realization of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to write down the deferred tax assets to their net realizable value.

We recognize the financial statement benefit of a tax position after determining that the relevant tax authority would more likely than not sustain the position following an audit under guidance contained in FASB ASC 740. For tax positions meeting a more-likely-than-not threshold, the amount recognized in the consolidated financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. Our policy is to reflect interest and penalties related to uncertain tax positions as part of the income tax expense, when and if they become applicable. We have applied this methodology to all tax positions for which the statute of limitations remains open, and there are no additions, reductions or settlements in unrecognized tax benefits during the Successor period from September 1, 2016 to December 31, 2016. We have no material uncertain tax positions as of December 31, 2016.

We have evaluated the full impact of the restructuring pursuant to the pre-packaged plan of reorganization and believe the reorganization will be treated as a taxable exchange under the Internal Revenue Code. Accordingly, we will have an initial tax basis in the assets acquired equal to their respective fair market values immediately after the reorganization and no tax attributes will carryover to us as a result of the reorganization. In addition, as part of the reorganization, we have elected to be treated as a corporation for U.S. Federal and state income tax purposes.

As of December 31, 2016, we have a federal net operating loss carryforward of \$23.1 million that will expire during 2036, and a state net operating loss carryforward of \$17.8 million that will expire beginning in 2031 and ending in 2036, if unused. We had deferred taxes assets of \$8.9 million for the net operating loss carryforwards. In addition, we had general business credits related to the enhanced oil recovery credit of \$1.3 million, which is available to reduce future federal regular income taxes, if any, through 2036. We have determined uncertainties exist as to the future utilization of the operating loss and credit carryforwards, therefore, has recorded a full valuation allowance against our net deferred tax asset.

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We are subject to income taxes in the U.S. federal jurisdiction and various states. Tax regulations within each jurisdiction are subject to the interpretations of the related tax laws and regulations and require significant judgment to apply. We are no longer subject to U.S. federal, state, and local, or non-U.S. income tax examinations by tax authorities for the years before 2013.

Reconciliation of the United States federal statutory income tax rate and our effective income tax rate from continuing operations on net income (loss) attributable to member interests are as follows for the Successor period from September 1, 2016 through December 31, 2016:

	Successor Period from	September 1, 2016 through December 31, 2016
Statutory tax rate	35%	
IRC Section 43 credits		3
State income taxes, net of federal tax benefit		2
		40
Valuation allowance on deferred tax assets		(40)
		-

The components of the net deferred tax asset (liability) are as follows for the Successor period from September 1, 2016 through December 31, 2016:

	Successor Period from	September 1, 2016 through December 31, 2016
Deferred tax assets related to:		
Unrealized hedge loss	\$	16,287
Accrued expenses		931
Capital loss carryforwards		1,800
Net operating loss carryforwards - Federal		8,078
Net operating loss carryforwards - State		858
IRC Section 43 credits		1,334
Total deferred tax assets		29,288
Valuation allowance on deferred tax assets		(12,657)
		16,631

Deferred tax liabilities related to:

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Properties and equipment	(16,515)
Incentive compensation	(116)
Total deferred tax liabilities	(16,631)
Net deferred tax asset (liability)	\$ -

Our Predecessor was not subject to U.S. federal and most state income taxes. The partners of our Predecessor were liable for income tax in regard to their distributive share of our Predecessor's taxable income. Such taxable income may vary substantially from net income reported in the consolidated financial statements. Certain corporate subsidiaries of our Predecessor were subject to federal and state income tax. The federal and state income taxes related to our Predecessor and these corporate subsidiaries were immaterial to the consolidated financial statements and were recorded in pre-tax income on a current basis only. Accordingly, no federal or state

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deferred income tax has been provided for in the consolidated financial statements during the Predecessor period from January 1, 2016 through August 31, 2016 and for the years ended December 31, 2015 and 2014.

Our Predecessor evaluated tax positions taken or expected to be taken in the course of preparing our Predecessor's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. Our Predecessor does not believe it has any tax positions taken within the consolidated financial statements that would not meet this threshold. Our Predecessor's policy was to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. Our Predecessor has not recognized any potential interest or penalties in the consolidated financial statements for the Predecessor period from January 1, 2016 through August 31, 2016 and for the years ended December 31, 2015 and 2014.

Our Predecessor files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, our Predecessor is no longer subject to income tax examinations by major tax authorities for years prior to 2013. Our Predecessor is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2016.

NOTE 13 – ISSUANCES OF UNITS

As of the Plan Effective Date, we had 5,416,667 shares of our common equity outstanding. Titan Management holds our Series A Preferred Share, which entitles Titan Management to 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

On the Plan Effective Date, all of our Predecessor's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any distribution or consideration.

On July 31, 2016, our Predecessor's 3,749,986 Class C Preferred Units that were issued to ATLS on July 31, 2013, were converted into 3,749,986 common units and the associated warrant issued to ATLS to purchase 562,497 of its common units expired.

On July 12, 2016, our Predecessor received notification from the New York Stock Exchange ("NYSE") that the NYSE commenced proceedings to delist its common units as a result of our failure to comply with the continued listed standards set forth in Section 802.01C of the NYSE Listed Company Manual to maintain an average closing price of \$1.00 per unit over a consecutive 30 day period. Our Predecessor's Class D Preferred Units and Class E Preferred Units were also delisted from the NYSE. Our Predecessor's common units, Class D Preferred Units, and Class E Preferred Units began trading on the OTC market on July 13, 2016 with the ticker symbol "ARPJ" for its common units, "ARPJP" for its Class D Preferred Units, and "ARPJN" for its Class E Preferred Units.

On May 12, 2016, due to the income tax ramifications of the potential strategic options our Predecessor was considering, our Predecessor's Board of Directors delayed the vesting date of approximately 110,000 units granted to employees, directors and officers until March 2017. The phantom units were set to vest between May 15, 2016 and August 31, 2016. As a result of the Chapter 11 Filings, our Predecessor's 2012 Long-Term Incentive Plan was

cancelled (see Note 15).

Our Predecessor had an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the “Agents”). Pursuant to its equity distribution agreement, our Predecessor sold from time to time through the Agents its common units representing limited partner interests of the Predecessor having an aggregate offering price of up to \$100.0 million. Sales of its common units were made in negotiated transactions or transactions that are deemed to be “at-the-market” offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the former trading market for its common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. Our Predecessor paid each of the Agents a commission, which in each case was not more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of its equity distribution agreement, our Predecessor sold common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of its common units to an Agent as principal was pursuant to the terms of a separate terms agreement between the Predecessor and such Agent. During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor issued 245,175 common limited partner units under its equity distribution program for net proceeds of \$0.2 million, net of \$4,000 in commissions and offering expenses paid. During the year ended December 31, 2015, our Predecessor issued 9,803,451 common limited partner units under the

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equity distribution program for net proceeds of \$44.2 million, net of \$1.1 million in commissions and offering expenses paid. No units were sold under the equity distribution program during the year ended December 31, 2014.

In August 2015, our Predecessor entered into a distribution agreement with MLV & Co. LLC (“MLV”), which it terminated and replaced in November 2015, when our Predecessor entered into a distribution agreement with MLV and FBR Capital Markets & Co. in which it sold its 8.625% Class D Cumulative Redeemable Perpetual Preferred Units (“Class D Preferred Units”) and Class E Cumulative Redeemable Perpetual Preferred Units (“Class E Preferred Units”). Under both the August 2015 ATM Agreement and the November 2015 ATM Agreement, our Predecessor did not issue any Class D Preferred units nor Class E Preferred Units under its preferred equity distribution program for the Predecessor period from January 1, 2016 through August 31, 2016. During the year ended December 31, 2015, our Predecessor issued 90,328 Class D Preferred Units and 1,083 Class E Preferred Units for net proceeds of \$0.9 million, net of \$0.3 million in commissions and offering expenses paid. Under the November 2015 ATM Agreement, our Predecessor did not issue any Class D Preferred Units nor Class E Preferred Units under the preferred equity distribution program, but incurred \$0.1 million of net offering expenses

In May 2015, in connection with the Arkoma Acquisition, our Predecessor issued 6,500,000 of its common limited partner units in a public offering at a price of \$7.97 per unit, yielding net proceeds of \$49.7 million. Our Predecessor used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under its Old First Lien Credit Facility.

In April 2015, our Predecessor issued 255,000 of its Class E Preferred Units at a public offering price of \$25.00 per unit for net proceeds of \$6.0 million.

On March 31, 2015, to partially pay its portion of a quarterly installment related to the Eagle Ford acquisition, our Predecessor issued an additional 800,000 Class D Preferred Units to the seller at a value of \$25.00 per unit.

In October 2014, our Predecessor issued 3,200,000 8.625% Class D Preferred Units at a public offering price of \$25.00 per Class D Preferred Unit, yielding net proceeds of approximately \$77.3 million from the offering, after deducting underwriting discounts and estimated offering expenses. Our Predecessor used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition (see Note 4). On March 31, 2015, to partially pay its portion of the quarterly installment related to the Eagle Ford Acquisition, our Predecessor issued an additional 800,000 Class D Preferred Units to the seller at a value of \$25.00 per unit. On January 15, 2015 our Predecessor paid an initial quarterly distribution of \$0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015 (see Note 14). Our Predecessor paid distributions on a quarterly basis, at an annual rate of \$2.15625 per unit, or 8.625% of the \$25.00 liquidation preference.

The Class D and Class E Preferred Units ranked senior to our Predecessor’s common units and Class C Preferred Units with respect to the payment of distributions and distributions upon a liquidation event.

In May 2014, in connection with the Rangely Acquisition (see Note 4), our Predecessor issued 15,525,000 of its common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of \$19.90 per unit, yielding net proceeds of approximately \$297.3 million.

In March 2014, in connection with the GeoMet Acquisition (see Note 4), our Predecessor issued 6,325,000 of its common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of \$21.18 per unit, yielding net proceeds of approximately \$129.0 million.

NOTE 14 – CASH DISTRIBUTIONS

We did not pay any distributions during the Successor period from September 1, 2016 through December 31, 2016.

Our Predecessor had a monthly cash distribution program whereby it distributed all of its available cash (as defined in its partnership agreement) for that month to its unitholders within 45 days from the month end. If our Predecessor's common unit distributions in any quarter exceed specified target levels, ATLS received between 13% and 48% of such distributions in excess of the specified target levels.

While outstanding, our Predecessor's Class B Preferred Units received regular quarterly cash distributions equal to the greater of (i) \$0.40 (or \$0.1333 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. In July 2015, the remaining 39,654 of our Predecessor's Class B Preferred Units were converted into common limited partner units.

Our Predecessor's Class C Preferred Units received regular quarterly cash distributions equal to the greater of (i) \$0.51 (or \$0.17 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. On May 5, 2016, our Predecessor's Board of

Directors elected to suspend our Predecessor's common unit and Class C preferred distributions, beginning with the month of March of 2016, due to the continued lower commodity price environment.

Our Predecessor paid quarterly distributions on its Class D Preferred Units at an annual rate of \$2.15625 per unit, \$0.5390625 per unit paid on a quarterly basis, or 8.625% of the \$25.00 liquidation preference. Our Predecessor paid quarterly distributions on its Class E Preferred Units at an annual rate of \$2.6875 per unit, or \$0.671875 per unit on a quarterly basis, or 10.75% of the \$25.00 liquidation preference. On June 16, 2016, our Predecessor's Board of Directors elected to suspend its quarterly distributions on its Class D Preferred Units and its Class E Preferred Units, beginning with the second quarter 2016 distribution, due to the continued lower commodity price environment. Our Predecessor's Class D Preferred Units and Class E Preferred Units accrued distributions of \$3.4 million and \$0.3 million, respectively, from April 15, 2016 through August 31, 2016. However, due to our Predecessor's distribution suspension and our Predecessor's recent Chapter 11 Filings, these amounts were not earned as the preferred units were cancelled without receipt of any consideration on the Plan Effective Date.

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid four monthly cash distributions totaling \$5.1 million to its common limited partners (\$0.0125 per unit per month); \$2.5 million to its Preferred Class C limited partners (\$0.0125 per unit per month); and \$0.2 million to its General Partner Class A holder (\$0.0125 per unit per month). During our Predecessor's year ended December 31, 2015, our Predecessor paid twelve monthly cash distributions totaling \$126.3 million to its common limited partners (\$0.1966 per unit in both January and February 2015, \$0.1083 per unit in March through November 2015, and \$0.0125 per unit in December 2015); \$7.8 million to its Preferred Class C limited partners (\$0.1966 per unit in both January and February 2015 and \$0.17 per unit in March through December 2015); approximately \$42,000 to its Preferred Class B limited partners (\$0.1966 per unit in both January and February 2015 and \$0.1333 per unit in March through July 2015); and \$4.8 million to its General Partner Class A holder (\$0.1966 per unit in both January and February 2015, \$0.1083 per unit in March through November 2015 and \$0.0125 per unit in December 2015). During our Predecessor's year ended December 31, 2014, our Predecessor paid one quarterly and ten monthly cash distributions totaling \$184.3 million to its common limited partners, \$9.5 million to its Preferred Class C limited partners, \$9.7 million to its Preferred Class B limited partners and \$4.8 million to its General Partner Class A holder. The amount per unit paid for all 2014 distributions was \$0.58 for the quarterly distribution paid in February 2014, \$0.1933 per unit for monthly distributions in March through July 2014 and \$0.1966 per unit for monthly distributions in August through December 2014.

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling \$4.4 million to its Class D Preferred units (\$0.5390625 per unit) for the period October 15, 2015 through April 14, 2016. During our Predecessor's year ended December 31, 2015, our Predecessor paid three distributions totaling \$8.5 million to its Class D Preferred units (\$0.6169270 per unit for the period October 2, 2014 through January 14, 2015 and \$0.539063 per unit for the period January 15, 2015 through October 14, 2015). There were no Class D Preferred unit distributions paid for the year ended December 31, 2014.

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling \$0.3 million to its Class E Preferred units (\$0.671875 per unit) for the period October 15, 2015 through April 14, 2016. During our Predecessor's year ended December 31, 2015, our Predecessor paid two \$0.3 million distributions to its Class E Preferred units (\$0.6793 per unit) for the period April 14, 2015 through October 14, 2015. There were no Class E Preferred unit distributions paid for the year ended December 31, 2014.

NOTE 15 — SHARE BASED COMPENSATION PLANS

Successor's Management Incentive Plan

On September 1, 2016, we adopted the Titan Energy, LLC Management Incentive Plan (the “MIP”) for the employees, directors and individual consultants of us and our affiliates. On October 26, 2016, the MIP was amended and restated to increase the number of shares that may be issued. The MIP permits the grant of options, phantom shares and restricted and unrestricted common shares, as well as dividend equivalent rights. Subject to adjustment in accordance with the MIP, a maximum of 655,555 common shares may be issued pursuant to awards under the MIP. Common Shares subject to forfeited awards or withheld to satisfy exercise prices or tax withholding obligations will again be available for delivery pursuant to other awards. The MIP has a term of 10 years and will be administered by the Board of Directors, which may delegate to a committee or the Company’s chief executive officer. On September 1, 2016, 138,750 common shares from the MIP were issued, at a grant date fair value of \$4.82 per share, and vested immediately as the service inception date was the date of the Chapter 11 Filings and the service completion date was the Plan Effective Date, resulting in \$0.7 million of non-cash compensation expense recorded in general and administrative expenses on the consolidated statement of operations for the Predecessor period from January 1, 2016 through August 31, 2016. Additionally, from September 1, 2016 through December 31, 2016, 438,537 common shares from the MIP were issued, at a grant date fair value of \$4.82 per share, 31,120 of which vested immediately and with remaining vesting 33% on each of the next three anniversaries of the date of grant, resulting in \$0.4 million of non-cash compensation expense recorded in general and administrative expenses on the consolidated statement of operations for the Successor period from September 1, 2016 through December 31, 2016. Of these shares, 18,500 were forfeited in the

Successor period from September 1, 2016 through December 31, 2016. The grant date fair value of the common shares issued was determined in connection with our estimate of the equity value of the Successor utilizing the discounted cash flow method (see Notes 3 and 9).

Of the 388,917 non-vested common shares outstanding under the MIP at December 31, 2016, 128,340 common shares will vest within the following twelve months. At December 31, 2016, we had \$1.7 million in unrecognized compensation expense related to unvested common shares outstanding under the MIP based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 1.7 years.

Predecessor's 2012 Long-Term Incentive Plan

Our Predecessor's 2012 Long-Term Incentive Plan ("2012 LTIP"), effective March 2012, provided incentive awards to officers, employees and directors and employees of our Predecessor's general partner and its affiliates, consultants and joint venture partners (collectively, the "Participants"), who performed services for our Predecessor. The 2012 LTIP was administered by the board of our Predecessor's general partner, a committee of the board or the board (or committee of the board) of an affiliate (the "LTIP Committee"). Under the 2012 LTIP, the LTIP Committee granted awards of phantom units, restricted units or unit options.

Predecessor's 2012 LTIP Phantom Units

Phantom units represented rights to receive a common unit, an amount of cash or other securities or property based on the value of a common unit, or a combination of common units and cash or other securities or property upon vesting. Phantom units were subject to terms and conditions determined by the LTIP Committee, which included vesting restrictions. In tandem with phantom unit grants, the LTIP Committee granted distribution equivalent rights ("DERs"), which were the right to receive an amount in cash, securities, or other property equal to, and at the same time as, the cash distributions or other distributions of securities or other property made by our Predecessor with respect to a common unit during the period that the underlying phantom unit was outstanding. During the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014, our Predecessor paid approximately \$15,000, \$0.7 million and \$2.0 million, respectively, with respect to the 2012 LTIP's DERs. These amounts were recorded as reductions of our Predecessor's partners' capital (deficit) on our Predecessor's consolidated balance sheets.

For the Predecessor year ended December 31, 2014, the 2012 LTIP phantom unit activity was as follows: Outstanding beginning of year: 839,808; Granted: 264,173; Vested: 274,414; Forfeited: 30,375; Outstanding end of year: 799,192. For the Predecessor year ended December 31, 2015, the 2012 LTIP phantom unit activity was as follows: Outstanding beginning of year: 799,192; Granted: 9,730; Vested: 472,278; Forfeited: 34,539; Outstanding end of year: 302,105. For the Predecessor period from January 1, 2016 through August 31, 2016, the 2012 LTIP phantom unit activity was as follows: Outstanding beginning of year: 302,105; Granted: 30,000; Vested: 24,679; Forfeited: 60,639; Outstanding end of year: none. As a result of the Chapter 11 Filings, our Predecessor's 2012 LTIP phantom units were cancelled.

During the Predecessor years ended December 31, 2015 and 2014, our Predecessor recognized 2012 LTIP unit based compensation expense for phantom units of \$4.1 million and \$6.4 million, respectively, which was recorded in general and administrative expenses on our Predecessor's consolidated statements of operations. During the Predecessor period from January 1, 2016 through August 31, 2016 our Predecessor recognized 2012 LTIP unit based compensation expense for phantom units of \$0.5 million, including \$0.8 million of remaining unrecognized compensation expense due to the 2012 LTIP cancellation, which was recorded in general and administrative expenses on our Predecessor's consolidated statement of operations.

Predecessor's 2012 LTIP Unit Options

A unit option was the right to purchase our Predecessor's common unit in the future at a predetermined price (the exercise price). The exercise price of each option was determined by the LTIP Committee and may be equal to or greater than the fair market value of a common unit on the date the option was granted. The LTIP Committee determined the vesting and exercise restrictions applicable to an award of options, if any, and the method by which the exercise price may be paid by the Participant. Unit option awards expired 10 years from the date of grant.

For the Predecessor year ended December 31, 2014, the 2012 LTIP unit option activity was as follows: Outstanding beginning of year: 1,482,675; Granted: none; Exercised: none; Forfeited: 24,375; Outstanding end of year: 1,458,300. For the Predecessor year ended December 31, 2015, the 2012 LTIP unit option activity was as follows: Outstanding beginning of year: 1,458,300; Granted: none; Exercised: none; Forfeited: 103,775; Outstanding end of year: 1,354,525. For the Predecessor period from January 1, 2016 through August 31, 2016, the 2012 LTIP unit option activity was as follows: Outstanding beginning of year: 1,354,525; Granted: none; Exercised: none; Forfeited: 40,689; Outstanding end of year: none. As a result of the Chapter 11 Filings, our Predecessor's 2012 LTIP unit options were cancelled.

During the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014, our Predecessor recognized 2012 LTIP unit based compensation expense for unit options of approximately \$31,000, \$0.8 million, and \$1.7 million, respectively, which was recorded in general and administrative expenses on our Predecessor's consolidated statements of operations.

Predecessor's 2012 LTIP Restricted Units

Restricted units were actual common units to be issued to a Participant that were subject to vesting restrictions and evidenced in such manner as the LTIP Committee deemed appropriate, including book-entry registration or issuance of one or more unit certificates. Prior to or upon the grant of an award of restricted units, the LTIP Committee would condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both. During the Predecessor period from January 1, 2016 through August 31, 2016 and the years ended December 31, 2015 and 2014, there were no restricted units granted or outstanding. As a result of the Chapter 11 Filings, our Predecessor's 2012 LTIP was cancelled.

NOTE 16 – OPERATING SEGMENT INFORMATION

Our operations include three reportable operating segments. These operating segments reflect the way we manage our operations and make business decisions. Operating segment data for the periods indicated were as follows (in thousands):

	Successor Period	Predecessor Period		
	September 1	January 1	Year Ended	Year Ended
	through	through	December 31,	December 31,
	December 31,	August 31,	December 31,	December 31,
	2016	2016	2015	2014
Gas and oil production:				
Revenues ⁽¹⁾	\$ 43,044	\$ 115,178	\$ 624,222	\$ 472,870
Operating costs and expenses	(39,418)	(86,566)	(169,653)	(182,226)
Depreciation, depletion and amortization expense	(23,218)	(68,647)	(145,161)	(229,482)
Asset impairment	—	—	(966,635)	(573,774)
Segment income (loss)	\$ (19,592)	\$ (40,035)	\$ (657,227)	\$ (512,612)
Well construction and completion:				
Revenues	\$ 2,326	\$ 19,157	\$ 76,505	\$ 173,564
Operating costs and expenses	(2,023)	(16,658)	(66,526)	(150,925)
Segment income	\$ 303	\$ 2,499	\$ 9,979	\$ 22,639
Other partnership management: ⁽²⁾				
Revenues	\$ 6,818	\$ 16,735	\$ 39,306	\$ 55,220
Operating costs and expenses ⁽³⁾	(5,084)	(21,476)	(18,775)	(25,532)
Depreciation, depletion and amortization expense	(659)	(13,684)	(12,817)	(10,441)
Segment income (loss)	\$ 1,075	\$ (18,425)	\$ 7,714	\$ 19,247
Reconciliation of segment income (loss) to net loss:				
Segment income (loss):				
Gas and oil production	\$ (19,592)	\$ (40,035)	\$ (657,227)	\$ (512,612)
Well construction and completion	303	2,499	9,979	22,639
Other partnership management ⁽²⁾	1,075	(18,425)	7,714	19,247
Total segment income (loss)	(18,214)	(55,961)	(639,534)	(470,726)
General and administrative expenses ⁽³⁾	(18,496)	(47,098)	(65,968)	(72,349)
Interest expense ⁽⁴⁾	(18,327)	(74,587)	(102,133)	(62,144)
Gain on early extinguishment of debt ⁽⁴⁾	—	26,498	—	—
Gain (loss) on asset sales and disposal ⁽⁴⁾	180	(479)	(1,181)	(1,869)
Reorganization items, net ⁽⁴⁾	(870)	(16,614)	—	—
Other income (loss) ⁽⁴⁾	22,413	(9,189)	—	—
Income tax (expense) benefit ⁽⁴⁾	—	—	—	—
Net loss	\$ (33,314)	\$ (177,430)	\$ (808,816)	\$ (607,088)

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Reconciliation of segment revenues to total revenues:

Gas and oil production	\$ 43,044	\$ 115,178	\$ 624,222	\$ 472,870
Well construction and completion	2,326	19,157	76,505	173,564
Other partnership management	6,818	16,735	39,306	55,220
Total revenues	\$ 52,188	\$ 151,070	\$ 740,033	\$ 701,654
Capital expenditures:				
Gas and oil production	\$ 23,990	\$ 22,684	\$ 111,329	\$ 193,131
Other partnership management	273	2,046	14,050	14,202
Corporate and other	70	164	1,759	5,395
Total capital expenditures	\$ 24,333	\$ 24,894	\$ 127,138	\$ 212,728

(1) Includes gain (loss) on mark-to-market derivatives.

(2) Includes revenues and expenses from well services, gathering and processing, administration and oversight, and other, net that do not meet the quantitative threshold for reporting segment information.

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- (3) General and administrative expenses have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented, except for \$10.9 million in provision for losses on Drilling Partnership receivables for the period January 1, 2016 through August 31, 2016 related a provision for losses related to certain receivables from the Drilling Partnerships to their estimated net realizable values.
- (4) Gain (loss) on asset sales and disposal, reorganization items, net, gain on early extinguishment of debt, interest expense and income tax (expense) benefit have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented.

	Successor December 31, 2016	Predecessor December 31, 2015
Balance sheet:		
Goodwill:		
Well construction and completion	\$ —	\$ 6,389
Other partnership management	—	7,250
Total goodwill	\$ —	\$ 13,639
Total assets:		
Gas and oil production	\$ 819,454	\$ 1,551,450
Well construction and completion	6,378	27,039
Other partnership management	11,804	66,641
Corporate and other	44,198	54,819
Total assets	\$ 881,834	\$ 1,699,949

NOTE 17 — SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserve Information. The preparation of our natural gas, oil and NGL reserve estimates was completed in accordance with our prescribed internal control procedures by our reserve engineers. Other than for our Rangely assets, for the periods presented, Wright and Company, Inc., an independent third-party reserve engineer, was retained to prepare a report of proved reserves related to us. The reserve information for us includes natural gas, oil and NGL reserves which are all located throughout the United States. The independent reserve engineer's evaluation was based on more than 40 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. For our Rangely assets, Cawley, Gillespie, and Associates, Inc. was retained to prepare a report of proved reserves. The independent reserve engineer's evaluation was based on more than 34 years of experience in the estimation of and evaluation of petroleum reserves, specified economic parameters, operating conditions, and government regulations. Our internal control procedures include verification of input data delivered to our third-party reserve specialist, as well as a multi-functional management review. The preparation of reserve estimates was overseen by our Director of Reservoir Engineering, who is a member of the Society of Petroleum Engineers and has more than 18 years of natural gas and oil industry experience. The reserve estimates were reviewed and approved by our senior engineering staff and management, with final approval by our President.

The reserve disclosures that follow reflect estimates of proved reserves, proved developed reserves and proved undeveloped reserves, net of royalty interests, of natural gas, crude oil and NGLs owned at year end and changes in proved reserves during the last three years. Proved oil, gas and NGL reserves are those quantities of oil, gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions,

operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved developed reserves are those reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for undeveloped reserves cannot be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence

using reliable technology establishing reasonable certainty. The proved reserves quantities and future net cash flows were estimated using an unweighted average of the first-day-of-the-month prices for each of the previous twelve months from the period presented, including adjustments related to regional price differentials and energy content.

There are numerous uncertainties inherent in estimating quantities of proven reserves and in projecting future net revenues and the timing of development expenditures. The reserve data presented represents estimates only and should not be construed as being exact. In addition, the standardized measures of discounted future net cash flows may not represent the fair market value of our oil, gas and NGL reserves or the present value of future cash flows of equivalent reserves, due to anticipated future changes in oil, gas and NGL prices and in production and development costs and other factors, for their effects have not been proved.

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Reserve quantity information and a reconciliation of changes in proved reserve quantities are as follows:

	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Total (MMcfe)
Predecessor, January 1, 2014	1,003,538	14,989	18,957	1,207,214
Extensions, discoveries and other additions ⁽¹⁾	58,455	3,372	3,986	102,603
Sales of reserves in-place	(169)	(2)	(11)	(247)
Purchase of reserves in-place ⁽²⁾	82,280	36,539	3,567	322,916
Transfers to Drilling Partnerships	(4,887)	(685)	(665)	(12,987)
Revisions of previous estimates ⁽³⁾	3,806	(4,941)	(2,689)	(41,974)
Production	(86,638)	(1,254)	(1,387)	(102,484)
Predecessor Balance, December 31, 2014	1,056,385	48,018	21,758	1,475,041
Extensions, discoveries and other additions ⁽¹⁾	6,442	2,492	218	22,702
Sales of reserves in-place	(2,713)	(2)	—	(2,725)
Purchase of reserves in-place ⁽²⁾	3,555	8,645	653	59,343
Transfers to Drilling Partnerships	(2,959)	(482)	(342)	(7,903)
Revisions of previous estimates ⁽³⁾	(377,067)	(11,992)	(13,382)	(529,311)
Production	(79,064)	(1,875)	(1,055)	(96,644)
Predecessor Balance, December 31, 2015	604,579	44,804	7,850	920,504
Extensions, discoveries and other additions	902	154	—	1,826
Sales of reserves in-place	(201)	—	(20)	(321)
Purchase of reserves in-place	1,615	13	—	1,693
Revisions of previous estimates ⁽³⁾	(41,487)	(7,003)	(1,593)	(93,063)
Production	(45,561)	(1,026)	(488)	(54,645)
Predecessor Balance, August 31, 2016	519,847	36,942	5,749	775,993
Successor Balance, September 1, 2016	519,847	36,942	5,749	775,993
Extensions, discoveries and other additions ⁽¹⁾	1,538	2,469	299	18,146
Sales of reserves in-place	(59)	—	—	(59)
Purchase of reserves in-place ⁽²⁾	52,419	170	56	53,775
Revisions of previous estimates ⁽³⁾	143,066	43	965	149,114
Production	(22,239)	(574)	(204)	(26,907)
Successor Balance, December 31, 2016	694,572	39,050	6,865	970,062
Proved developed reserves at:				
Predecessor January 1, 2014	766,631	3,459	7,676	833,441
Predecessor December 31, 2014	887,819	30,538	12,005	1,143,077
Predecessor December 31, 2015	567,993	25,484	6,334	758,901
Predecessor August 31, 2016	508,922	18,863	4,637	649,922
Successor December 31, 2016	690,894	24,936	5,975	876,360
Proved undeveloped reserves at:				
Predecessor January 1, 2014	236,907	11,530	11,281	373,773
Predecessor December 31, 2014	168,566	17,480	9,753	331,964
Predecessor December 31, 2015	36,586	19,320	1,516	161,602
Predecessor August 31, 2016	10,925	18,079	1,112	126,071

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Successor December 31, 2016	3,678	14,114	890	93,702
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- (1) For the Successor period from September 1, 2016 through December 31, 2016, the increase represents PUD additions related to our development and leasing activity in the Eagle Ford Shale. For the Predecessor year ended December 31, 2015, the increase represents PUD additions related to our development activity in the Eagle Ford Shale. For the Predecessor year ended December 31, 2014, the increase was primarily due to the addition of Marble Falls wells.
- (2) Represents purchase of proved reserves from Drilling Partnership consolidations for the Successor period from September 1, 2016 through December 31, 2016 (see Note 10). Represents purchase of proved reserves from the Eagle Ford Acquisitions for the Predecessor year ended December 31, 2015 (see Note 4). Represents purchase of proved reserves from the Rangely, Eagle Ford and GeoMet Acquisitions for the Predecessor year ended December 31, 2014 (see Note 4).
- (3) See “Revisions of Previous Estimates” section below for additional discussion and analysis of significant components of revisions of previous estimates.

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Revisions of Previous Estimates

The following represents the unweighted average of the first-day-of-the-month prices for each of the previous twelve months from the periods presented above:

	Successor December 31, 2016	Predecessor August 31, 2016	December 31, 2015	December 31, 2014
Unadjusted Prices				
Natural gas (per MMBtu)	\$2.48	\$2.26	\$ 2.59	\$4.35
Oil (per Bbl)	\$42.75	\$41.87	\$ 50.28	\$94.99
Natural gas liquids (per Bbl)	\$19.57	\$13.07	\$ 11.02	\$30.21

For the Successor period from September 1, 2016 through December 31, 2016 we had positive revisions of 145,507 MMcfe due to our production outperforming the comparable period's forecast and 41,859 MMcfe due to increases in pricing, partially offset by a negative revision of 38,252 MMcfe due to the removal of proved undeveloped properties that became uneconomic due to pricing.

For the Predecessor period from January 1, 2016 through August 31, 2016 we had negative revisions of 66,376 MMcfe due to decreases in pricing and 42,361 MMcfe due to the removal of proved undeveloped properties that became uneconomic due to pricing, partially offset by positive revision of 15,674 MMcfe due to our production outperforming the comparable period's forecast.

For the Predecessor year ended December 31, 2015, we had negative revisions of 260,727 MMcfe due to decreases in pricing, 220,283 MMcfe due to the removal of proved undeveloped properties that became uneconomic due to pricing and 48,301 MMcfe due to production underperforming previous year's forecast.

For the Predecessor year ended December 31, 2014, we had negative revisions of 147,189 MMcfe due to the removal of proved undeveloped properties that became uneconomic due to pricing, partially offset by positive revisions of 58,690 MMcfe due to our production outperforming the comparable period's forecast and 46,525 MMcfe due to increases in pricing.

Capitalized Costs Related to Oil and Gas Producing Activities. The components of our capitalized costs related to oil and gas producing activities at the periods indicated were as follows (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
Natural gas and oil properties:		
Proved properties	\$717,839	\$3,585,839
Unproved properties	74,434	213,047
Support equipment	2,643	44,921
	794,916	3,843,807
Accumulated depreciation, depletion and amortization	(21,056)	(2,691,692)

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Net capitalized costs	\$773,860	\$1,152,115
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Results of Operations from Oil and Gas Producing Activities. The results of operations related to our oil and gas producing activities during the periods indicated were as follows (in thousands):

	Successor Period from September 1, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues	\$86,936	\$ 139,094	\$ 356,999	\$ 470,051
Production costs	(39,418)	(86,566)	(169,653)	(182,226)
Depletion	(21,012)	(64,049)	(145,161)	(229,482)
Asset impairment ⁽¹⁾	—	—	(966,635)	(573,774)
Income tax (expense) benefit	—	—	—	—
	\$26,506	\$ (11,521)	\$ (924,450)	\$ (515,431)

(1) During the Predecessor year ended December 31, 2015, our Predecessor recognized \$966.6 million of asset impairment primarily related to oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, net of \$85.8 million of future hedge gains reclassified from accumulated other comprehensive income, and \$6.6 million of asset impairment of unproved acreage in the New Albany Shale, which was impaired due to expiring acreage and no intention to pursue development.. During the Predecessor year ended December 31, 2014, our Predecessor recognized \$573.8 million of asset impairment consisting of \$555.7 million related to oil and gas properties within the Appalachia and Mid-Continent operating areas, which was net of \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income, and \$18.1 million of goodwill impairment resulting from the decline in overall commodity prices.

Costs Incurred in Oil and Gas Producing Activities. Our costs incurred in our oil and gas activities during the periods indicated were as follows (in thousands):

Successor Period from September 1, 2016 through December 31, 2016	Predecessor Period from January 1, 2016 through December 31, 2015	Year Ended December 31, 2015	Year Ended December 31, 2014

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		August 31, 2016		
Property acquisition costs:				
Proved properties	\$1,307	\$2,359	\$ 11,513	\$ 699,451
Unproved properties	—	—	43,820	10,978
Exploration costs ⁽¹⁾	383	943	1,601	722
Development costs	20,835	12,395	73,288	164,853
Total costs incurred in oil & gas producing activities	\$22,525	\$15,697	\$ 130,222	\$ 876,004

(1) There were no exploratory wells drilled during the periods presented.

Standardized Measure of Discounted Future Cash Flows. The following table presents the standardized measure of estimated discounted future net cash flows relating our proved oil and gas reserves. The estimated future production was priced at an unweighted average of the first-day-of-the-month prices for each of the previous twelve months from the periods presented, adjusted only for regional price differentials and energy content. The resulting estimated future cash inflows were reduced by estimated future costs to develop and produce the proved reserves based on year-end cost levels and includes the effect on cash flows of settlement of asset retirement obligations on gas and oil properties. For the Successor period presented, future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties as well as the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards and alternative minimum tax credits. For the Predecessor periods presented, future income tax expenses were not applicable since our Predecessor allocated taxable income to its unit holders. The resulting annual net cash inflows were then discounted using a 10% annual rate. The standardized measure of future cash flows was prepared using the prevailing economic conditions existing at the dates presented and such conditions continually change. Accordingly, such information should not serve as a

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basis in making any judgment on the potential value of recoverable reserves or in estimating future results of operations (in thousands):

	Successor	Predecessor	December 31,	December 31,
	December 31,	August 31,	2015	2014
	2016	2016		
Future cash inflows	\$3,136,665	\$2,484,094	\$3,514,198	\$9,317,915
Future production costs	(1,774,007) (1,506,678)	(1,836,779)	(4,188,364)
Future development costs	(394,863) (460,195)	(1,156,367)	(1,157,305)
Future income tax expense	(99,233) —	—	—
Future net cash flows	868,562	517,221	521,052	3,972,246
Less 10% annual discount for estimated timing of cash flows	(412,904) (249,576)	(18,283)	(1,987,975)
Standardized measure of discounted future net cash flows	\$455,658	\$267,645	\$502,769	\$1,984,271

Change in Standardized Discounted Cash Flows. The following table summarizes the changes in the standardized measure of discounted future net cash flows from estimated production of proved oil, gas and NGL reserves (in thousands).

	Successor	Predecessor	December 31,	December 31,
	December 31,	August	2015	2014
	2016	31, 2016		
Balance, beginning of period	\$267,645	\$502,769	\$1,984,271	\$1,076,182
Increase (decrease) in discounted future net cash flows ⁽¹⁾				
Sales of oil and gas produced, net of related costs	(37,136) (57,700)	(129,352)	(272,961)
Net changes in prices and production costs	70,716	(237,106)	(1,453,854)	339,718
Revisions of previous quantity estimates	101,366	(102)	(52,775)	4,352
Development costs incurred	18,838	—	58,117	52,077
Changes in future development costs	20,098	10,492	(152,305)	(90,887)
Transfers to Drilling Partnerships	—	—	(13,291)	(2,966)
Extensions, discoveries, and improved recovery less related costs	16,438	(57)	13,980	60,832
Purchases of reserves in-place	24,794	711	53,102	737,101
Sales of reserves in-place	(7) (117)	(2,162)	(332)
Accretion of discount	26,765	50,277	198,427	107,618
Estimated settlement of asset retirement obligations	(5,886) (1,522)	(216)	(16,708)
Estimated proceeds on disposals of well equipment	(1,732) —	(1,173)	(21,906)
Changes in production rates (timing) and other	—	—	—	12,151

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Net changes in income taxes	(46,241)	—	—	—
Outstanding, end of period	\$455,658		\$267,645	\$502,769	\$1,984,271

(1) See “Reserve Quantity Information” and “Revisions of Previous Estimates” sections above for additional discussion and analysis of significant changes within the periods presented.

NOTE 18 — QUARTERLY RESULTS (UNAUDITED)

	Successor		Predecessor		
	Period from		Period		
	September 1		from		
	through		July		
	Fourth	September	August	Second	First
	Quarter	30, 2016	31, 2016	Quarter	Quarter
	(in thousands, except unit data)				
Year ended December 31, 2016:					
Revenues	\$31,753	20,435	\$64,686	\$(16,824)	\$103,208
Net loss attributable to common shareholders and preferred member	\$(25,783)	\$(7,531)	\$—	\$—	\$—
Net loss attributable to common limited partners and the general partner's interests	\$—	—	\$(48,624)	\$(141,934)	\$9,115
Allocation of net income (loss) attributable to common limited partners and the general partner:					
Common limited partners' interest	\$—	—	\$(47,651)	\$(139,096)	\$8,933
General partner's interest	—	—	(973)	(2,838)	182
Allocation of net loss attributable to:					
Series A Preferred member	\$(515)	\$(151)	\$—	\$—	\$—
Common shareholders	\$(25,268)	\$(7,380)	\$—	\$—	\$—
Net loss attributable to common shareholders per share/common limited partners per unit:					
Basic	\$(4.66)	(1.36)	\$(0.46)	\$(1.36)	\$0.09
Diluted	\$(4.66)	(1.36)	\$(0.46)	\$(1.36)	\$0.09

(1) For the Predecessor second quarter and for the period from July 1, 2016 through August 31, 2016, 274,000 and 247,000 phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the Predecessor second quarter and for the period from July 1, 2016 through August 31, 2016, potential common limited partner units issuable upon (a) conversion of our Class C preferred units and (b) exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As the Class D and Class E preferred units were convertible only upon a change of control event, they are not considered dilutive securities for earnings per unit purposes.

	Fourth	Third	Second	First
	Quarter	Quarter	Quarter	Quarter
	(in thousands, except unit data)			
Year ended December 31, 2015:				

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Revenues	\$142,424	\$257,895	\$96,125	\$243,589
Net loss attributable to common limited partners and the general partner's interest ⁽²⁾	\$(293,013)	\$(565,147)	\$(51,044)	\$83,919
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	\$(287,153)	\$(553,844)	\$(50,613)	\$80,344
General partner's interest	(5,860)	(11,303)	(431)	3,575
Net loss attributable to common unitholders per unit:				
Basic	\$(2.81)	\$(5.73)	\$(0.56)	\$0.93
Diluted (1)	\$(2.81)	\$(5.73)	\$(0.56)	\$0.91

(1) For the second, third, and fourth quarters of the year ended December 31, 2015, approximately 469,000, 346,000 and 309,000 units, respectively, were excluded from the computation of diluted net income (loss) per common unit, because the inclusion of such units would have been anti-dilutive. For the second, third, and fourth quarters of the year ended December 31, 2015, potential common limited partner units issuable upon conversion of the Partnership's Class B and Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. For the first, second, third and fourth quarters of the year ended December 31, 2015, potential common limited partner units issuable upon exercise of the common unit warrants issued with the Class C preferred

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units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive.

(2) Includes asset impairment charges of \$672.2 million and \$294.4 million in the third and fourth quarters of 2015, respectively.

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

None.

ITEM 9A: CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our periodic reports filed pursuant to the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2016, our disclosure controls and procedures were effective at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based upon criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the 2013 Internal Control – Integrated Framework (COSO framework).

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods cannot be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.

There have been no changes in our internal control over financial reporting during the fourth quarter of 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Based on our evaluation under the COSO framework, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2016.

ITEM 9B: OTHER INFORMATION

None.

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PART III

ITEM 10: DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors and Executive Officers

The following table sets forth information regarding our directors and executive officers.

Name	Age	Position(s)
Edward E. Cohen	78	Executive Chairman and Class A Director
Jonathan Z. Cohen	46	Executive Vice Chairman and Class A Director
Daniel C. Herz	40	Chief Executive Officer and Class A Director
Jeffrey M. Slotterback	35	Chief Financial Officer and Class A Director
Eugene I. Davis	62	Class B Director
Michael A. Zawadzki	36	Class B Director
Michael C. Watchorn	57	Class B Director
Mark D. Schumacher	54	President
Lisa Washington	49	Vice President, Chief Legal Officer and Corporate Secretary
Matthew J. Finkbeiner	37	Chief Accounting Officer

Edward E. Cohen has been our Executive Chairman and a Class A Director since September 2016. Before then, he served as the Executive Chairman of our predecessor, Atlas Resource Partners, L.P., since August 2015 and the Chief Executive Officer and Executive Vice Chairman of Atlas Energy Group, LLC, our predecessor's general partner, since February 2015. Mr. Cohen served as President of Atlas Energy Group from February 2015 to April 2015, and before that he was Chairman and Chief Executive Officer since February 2012. Mr. Cohen has also served as Chairman of the board of directors and Chief Executive Officer of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Mr. Cohen was the Chairman of the board of directors of Atlas Energy, L.P.'s general partner from its formation in January 2006 until February 2011, when he became its Chief Executive Officer and President until February 2015. Mr. Cohen served as the Chief Executive Officer of Atlas Energy's general partner from its formation in January 2006 until February 2009. Mr. Cohen served on the executive committee of Atlas Energy's general partner from 2006 until February 2015. Mr. Cohen also was the Chairman of the board of directors and Chief Executive Officer of Atlas Energy, Inc. (formerly known as Atlas America, Inc.) from its organization in 2000 until February 2011 and also served as its President from September 2000 to October 2009. Mr. Cohen was the Executive Chair of the managing board of directors of Atlas Pipeline Partners GP, LLC ("Atlas Pipeline GP") from its formation in 1999 until February 2015. Mr. Cohen was the Chief Executive Officer of Atlas Pipeline GP from 1999 to January 2009. Mr. Cohen was the Chairman of the board of directors and Chief Executive Officer of Atlas Energy Resources, LLC and its manager, Atlas Energy Management, Inc. from their formation in June 2006 until February 2011. In addition, Mr. Cohen was a director of Resource America, Inc. (formerly a publicly-traded specialized asset management company) from 1988 until September 2016 and its Chairman of its board of directors from 1990 until September 2016 and was its Chief Executive Officer from 1988 until 2004, and President from 2000 until 2003; Chair of the board of directors of Resource Capital Corp. (a publicly-traded real estate investment trust) since its formation in 2005 until November 2009 and served on its board of directors until September 2016; and Chair of the board of directors of Brandywine Construction & Management, Inc. (a property management company) since 1994. Mr. Cohen is the father of Jonathan Z. Cohen. Mr. Cohen has been active in the energy business for over 30 years. Mr. Cohen's strong financial and energy industry experience, along with his deep knowledge of the company resulting from his long tenure with the company and its predecessors, enables Mr. Cohen to provide valuable perspectives on many issues facing the company. Mr. Cohen's service on the Board creates an important link between management and the Board and provides the

company with decisive and effective leadership. Mr. Cohen's extensive experience in founding, operating and managing public and private companies of varying size and complexity enables him to provide valuable expertise to the company. Additionally, among the reasons for his appointment as a director, Mr. Cohen brings to the Board the vast experience that he has accumulated through his activities as a financier, investor and operator in various parts of the country. These diverse experiences have enabled Mr. Cohen to bring unique perspectives to the Board, particularly with respect to business management, financial markets and financing transactions and corporate governance issues.

Jonathan Z. Cohen has served as our Executive Vice Chairman and a Class A Director since September 2016. Before then, he served as our predecessor's Executive Vice Chairman since August 2015 and the Executive Chairman of the board of directors of Atlas Energy Group, LLC, our predecessor's general partner, since February 2015, and before that was Vice Chairman of our predecessor's general partner since February 2012. Mr. Cohen has served as the Executive Vice Chairman of the board of directors of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Mr. Cohen served as Executive Chairman of the board of directors of Atlas Energy, L.P.'s general partner from January 2012 until February 2015. Before that, he served as Chairman of the board of directors of Atlas Energy's general partner from February 2011 until January 2012 and as Vice Chairman of the board of directors of its general partner from its formation in January 2006 until February 2011. Mr. Cohen served as chairman of the executive committee of Atlas Energy's general partner from 2006 until February 2015. Mr. Cohen was the Vice Chairman of the board of

directors of Atlas Energy, Inc. from its incorporation in September 2000 until February 2011. Mr. Cohen was the Executive Vice Chair of the managing board of directors of Atlas Pipeline GP from its formation in 1999 until February 2015. Mr. Cohen was the Vice Chairman of the board of directors of Atlas Energy Resources, LLC and its manager, Atlas Energy Management, Inc. from their formation in June 2006 until February 2011. Mr. Cohen was a senior officer of Resource America, Inc. (formerly a publicly-traded specialized asset management company) from 1998 until September 2016, serving as the Chief Executive Officer from 2004 to September 2016, President from 2003 to September 2016 and a director from 2002 to September 2016. Mr. Cohen served as Chief Executive Officer, President and a director of Resource Capital Corp. from its formation in 2005 until September 2016. Since September 2016, Mr. Cohen has served as the founder and Chief Executive Officer of Hepco Capital Management, LLC, a recently formed private investment firm. Mr. Cohen is a son of Edward E. Cohen. Mr. Cohen's extensive knowledge of the company resulting from his long length of service with the company and its predecessors, as well as his strong financial and industry experience, allow him to contribute valuable perspectives on many issues facing the Company. Mr. Cohen's service on the Board creates an important link between management and the Board and provides the company with decisive and effective leadership. Mr. Cohen's involvement with public and private entities of varying size, complexity and focus and raising debt and equity for such entities provides him with extensive experience and contacts that are valuable to the company. Additionally, among the reasons for his appointment as a director, Mr. Cohen's financial, business, operational and energy experience as well as the experience that he has accumulated through his activities as a financier and investor, add strategic vision to our Board to assist with our growth, operations and development. Mr. Cohen is able to draw upon these diverse experiences to provide guidance and leadership with respect to exploration and production operations, capital markets and corporate finance transactions and corporate governance issues.

Daniel C. Herz has served as our Chief Executive Officer and a Class A Director since September 2016. Before then, he served as our predecessor's Chief Executive Officer since August 2015 and as President of Atlas Energy Group, LLC, our predecessor's general partner since April 2015. Mr. Herz has served as President and a director of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Mr. Herz served as Senior Vice President of Corporate Development and Strategy of our predecessor's general partner from March 2012 to April 2015. Mr. Herz served as Senior Vice President of Corporate Development and Strategy of Atlas Energy's general partner from February 2011 until February 2015. Mr. Herz was Senior Vice President of Corporate Development of Atlas Pipeline Partners GP, LLC from August 2007 until February 2015. He also was Senior Vice President of Corporate Development of Atlas Energy, Inc. and Atlas Energy Resources, LLC from August 2007 until February 2011. Before that, Mr. Herz was Vice President of Corporate Development of Atlas Energy, Inc. and Atlas Pipeline Partners GP, LLC from December 2004 and of Atlas Energy's general partner from January 2006. Mr. Herz's significant experience as a chief executive officer for the Company and related entities, together with his corporate development experience, enables him to provide the Board with executive counsel on a full range of business, strategic and professional matters.

Jeffrey M. Slotterback has served as our Chief Financial Officer and a Class A Director since September 2016. Before then, he served as our predecessor's Chief Financial Officer since September 2015. Mr. Slotterback has served as Chief Financial Officer of Atlas Energy Group, our predecessor's general partner, since September 2015 and served as its Chief Accounting Officer from March 2012 to October 2015. Mr. Slotterback has also served as the Chief Financial Officer of the general partner of Atlas Growth Partners, L.P. since September 2015 and served as its Chief Accounting Officer from its inception in 2013 to October 2015. Mr. Slotterback served as Chief Accounting Officer of Atlas Energy's general partner from March 2011 until February 2015. Mr. Slotterback was the Manager of Financial Reporting for Atlas Energy, Inc. from July 2009 until February 2011 and then served as the Manager of Financial Reporting for Atlas Energy GP, LLC from February 2011 until March 2011. Mr. Slotterback served as Manager of Financial Reporting for both Atlas Energy GP, LLC and Atlas Pipeline Partners GP, LLC from May 2007 until July 2009. Mr. Slotterback was a Senior Auditor at Deloitte and Touche, LLP from 2004 until 2007, where he focused on energy and health care clients. Mr. Slotterback is a Certified Public Accountant. Mr. Slotterback's significant

accounting and financial experience, as well as his familiarity with the Company and its operations, enable him to provide the board with important insight into the Company.

Eugene I. Davis has served as a Class B director since September 2016. Mr. Davis is the Chairman and Chief Executive Officer of PIRINATE Consulting Group, LLC, since 1997, a privately held consulting firm specializing in turnaround management, merger and acquisition consulting and hostile and friendly takeovers, proxy contests and strategic planning advisory services for domestic and international public and private business entities. From 1990 to 1997, Mr. Davis served as President, Vice Chairman, and Director of Emerson Radio Corporation, and from 1996 to 1997 he served as Chief Executive Officer and Vice Chairman of Sport Supply Group, Inc. He began his career as an attorney and international negotiator with Exxon Corporation and Standard Oil Company (Indiana) and was in private practice from 1984 to 1998. Mr. Davis currently serves as Chairman of the Board of Atlas Iron Limited (ASX: AGO), U.S. Concrete, Inc. (Nasdaq: USCR), and WMIH Corp. (Nasdaq: WMIH), and also serves as a director of Verso Corporation (NYSE: VRS) and Genco Shipping & Trading Limited (NYSE:GNK), as well as certain non-SEC reporting companies. On March 3, 2017, Mr. Davis announced his intention to not stand for reelection to the board of Genco Shipping & Trading Limited at its annual general meeting to be held on May 17, 2017, and on March 15, 2017, Mr. Davis announced his intention to not stand for reelection to the board of directors of WMIH Corp. at its 2017 annual general meeting scheduled to be held on June 1, 2017. During the past five years, Mr. Davis has also been a director of the following SEC registrants: Atlas Air Worldwide Holdings, Inc., The Cash Store Financial Services, Inc., Dex One Corp., Global Power Equipment Group, Inc., Goodrich Petroleum Corp., Great Elm Capital Corporation, GSI Group, Inc., Hercules Offshore, Inc., HRG Group, Inc., Knology, Inc., SeraCare Life Sciences, Inc., Spansion, Inc.

and Spectrum Brands Holdings, Inc. We believe that Mr. Davis' professional experience and expertise with strategic planning, mergers and acquisitions, finance, accounting and corporate governance, coupled with his strong leadership skills, makes him an asset to our Board of Directors.

Michael A. Zawadzki has served as a Class B director since September 2016. Mr. Zawadzki is a Senior Managing Director with GSO Capital Partners, focused principally on the sourcing, execution, and management of investments in the energy sector. Mr. Zawadzki is a senior member of GSO's energy team and sits on the investment committees for GSO's energy funds. Mr. Zawadzki also serves as a Portfolio Manager of GSO Community Development Capital Group LP, a fund formed to provide land acquisition and development capital in partnership with residential homebuilders. Since joining GSO in July 2006, Mr. Zawadzki has led or played a critical role in transactions totaling over \$3 billion of invested capital. Prior to joining GSO, from 2004 to 2006, Mr. Zawadzki was with Citigroup Private Equity, where he completed numerous private equity and subordinated debt investments. Previously from 2002 to 2004, Mr. Zawadzki worked in the investment banking division of Salomon Smith Barney, focused on the media and telecommunications industries. Mr. Zawadzki serves on the board of directors of Community Development Capital Group. The Company believes his background and skill set make Mr. Zawadzki well-suited to serve as a member of the Board.

Michael C. Watchorn has served as a Class B director since September 2016. Mr. Watchorn served as a Senior Vice President and Portfolio Manager in both the Global Corporate Credit and Distressed Credit groups of Pacific Investment Management Company from 2007 until December 2015 where he conferred with corporate executives and board members to assess companies' operating and financial strategies and performance. Prior to that, from 1994 through 2005, Mr. Watchorn served as a Managing Director and High Yield Bond Portfolio Manager at Oaktree Capital Management (and its predecessor unit at Trust Company of the West), where he directed analysts' research efforts and reviewed the analyses produced in support of portfolio activities. Mr. Watchorn has also previously held positions with Citicorp from 1989 through 1994 and with International Business Machines from 1984 until 1989. Mr. Watchorn currently serves as a Visiting Lecturer of Economics at Claremont McKenna College. Mr. Watchorn is a Chartered Financial Analyst. We believe that Mr. Watchorn's years of experience and strong financial background, as well as his work as a consultant, allows the Board of Directors to benefit from his business acumen and valuable financial experience.

Mark D. Schumacher has served as our President since September 2016. Before then, he served as our predecessor's President since April 2015 and as a Senior Vice President of Atlas Energy Group, our predecessor's general partner, since April 2015. Mr. Schumacher served as Chief Operating Officer of our predecessor's general partner from October 2013 to April 2015. Mr. Schumacher has been the Executive Vice President of Operations of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. He has served as Executive Vice President of Atlas Energy, L.P. from July 2012 to October 2013. From August 2008 to July 2012, Mr. Schumacher served as President of Titan Operating, LLC, which we acquired in July 2012. From November 2006 until August 2008, Mr. Schumacher served as President of Titan Resources, LLC, which built an acreage position in the Barnett Shale that it sold to XTO Energy in October 2008. From February 2005 to November 2006, Mr. Schumacher served as the Team Lead of EnCana Oil & Gas (USA) Inc. where he was responsible for Encana's Barnett Shale development. Mr. Schumacher was an engineer with Union Pacific Resources from 1984 to 2000. Mr. Schumacher has over 33 years of experience in drilling, production and reservoir engineering management, operations and business development in East Texas, Austin Chalk, Barnett Shale, Mid-Continent, the Rockies, the Gulf of Mexico, Latin America and Canada.

Lisa Washington has been our Vice President, Chief Legal Officer and Secretary since September 2016. Before then, she served as our predecessor's Vice President, Chief Legal Officer and Secretary since August 2015 and served as Senior Vice President of Atlas Energy Group, our predecessor's general partner, since September 2015, Chief Legal Officer and Secretary of our predecessor's general partner since February 2012 and served as Vice President of our predecessor's general partner from February 2015 to September 2015. Ms. Washington has served as Chief Legal

Officer and Secretary of the general partner of Atlas Growth Partners, L.P. since its inception in 2013. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy GP, LLC from January 2006 to October 2009, and as a Senior Vice President from October 2008 to October 2009, and as Vice President, Chief Legal Officer and Secretary from February 2011 to February 2015. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Pipeline Partners GP, LLC from November 2005 to October 2009, a Senior Vice President from October 2008 to October 2009 and a Vice President from November 2005 until October 2008. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy, Inc. from November 2005 until February 2011, a Senior Vice President from October 2008 until February 2011, and a Vice President from November 2005 until October 2008. Ms. Washington served as Chief Legal Officer and Secretary of Atlas Energy Resources, LLC from 2006 until February 2011, a Senior President from July 2008 until February 2011 and a Vice President from 2006 until July 2008. From 1999 to 2005, Ms. Washington was an attorney in the business department of the law firm of Blank Rome LLP.

Matthew J. Finkbeiner has been our Chief Accounting Officer since September 2016. Before then, he served as our predecessor's Chief Accounting Officer since October 2015. Mr. Finkbeiner has been the Chief Accounting Officer of Atlas Energy Group, our predecessor's general partner, and the general partner of Atlas Growth Partners, L.P. since October 2015. Mr. Finkbeiner has held positions with Deloitte & Touche LLP, including Audit Senior Manager from September 2010 until joining ATLS in October 2015, Audit Manager from September 2007 to September 2010, and Audit Senior/Staff from September 2002 until September 2007.

While at Deloitte & Touche LLP, Mr. Finkbeiner managed audits for a diversified base of clients in the oil and gas industry, including master limited partnerships. Mr. Finkbeiner is a Certified Public Accountant.

Board Structure

Our Board consists of seven members divided into two classes: Class A directors Edward Cohen, Jonathan Cohen, Daniel Herz and Jeffrey Slotterback and Class B directors Michael Zawadzki, Michael Watchorn and Eugene Davis.

Pursuant to our LLC Agreement, the Class A directors were designated by Titan Management as the holder of the Series A Preferred Share. Mr. Zawadzki was designated by GSO, which had indirectly held a majority of the debt under our predecessor's second lien credit agreement as well as a portion of our predecessor's senior notes. Messrs. Watchorn and Davis were designated by a majority in interest of the holders of the senior notes that were cancelled pursuant to the Plan.

Our LLC Agreement provides that the Board consists of seven directors, divided into two classes: four Class A directors and three Class B directors. At each annual meeting commencing with the 2019 annual meeting:

- for so long as the Series A Preferred Share is outstanding, the appointment of Class A directors shall be made by a majority of the Class A directors then in office; and
- the Class B directors will be elected by the holders of the Common Shares in accordance with the provisions of our LLC Agreement.

Following the consummation of the acquisition of the Series A Preferred Share pursuant to the Preferred Share Call Right (defined below), all directors will be Class B directors subject to election by the holders of the Common Shares. We have the continuing right to purchase the Series A Preferred Share at fair market value, subject to the approval of 67% of the outstanding Common Shares not held by Titan Management or its affiliates (the "Preferred Share Call Right").

Prior to the first date on which our ratio of total debt (as defined in the First Lien Exit Facility), as of such date, to EBITDA (as defined in the First Lien Exit Facility, excluding, without duplication, gains and losses arising out of mark to market and cash settlement, prior to September 1, 2016, of commodity derivative contracts) for the 12 months preceding the determination date is less than 3.5 to 1 (the "Fallaway Date"), GSO will have the right to nominate one Class B director, and the other two Class B directors shall be nominated by the other Class B directors then in office. On and after the Fallaway Date, nominations for Class B directors will be made by the Nominating and Governance Committee of the Board and may also be made by any individual shareholder holding 10% or more of the outstanding Common Shares. In addition, certain parties to the Registration Rights Agreement will have the ability to pool their ownership for purposes of establishing the 10% ownership threshold for nominations.

Any vacancies in Class A directors may be filled by a majority of the remaining Class A directors then in office. Prior to the Fallaway Date, vacancies in the GSO-nominated Class B director will be filled by GSO, and vacancies in the other Class B directors will be filled by a majority of the other remaining Class B directors then in office. On and after the Fallaway Date, vacancies in the Class B directors will be filled by the Nominating and Governance Committee,

subject to the approval of the Board.

Our LLC Agreement provides that certain matters may not be delegated by the Board (the “Non-Delegated Duties”), including, but not limited to: (i) the terms of issuance of Company securities; (ii) distributions; (iii) agreements with expected values greater than \$20 million; (iv) selection and employment of named executive officers; (v) legal matters with expected values greater than \$5 million; (vi) indemnification; (vii) national securities exchange matters; (viii) expenditures and lending and borrowing of money; (ix) determination of eligible holders and ineligible holders; (x) redemption of securities of ineligible holders; (xi) designation of additional unrestricted persons; (xii) the retention of our named executive officers; (xiii) formation of, contributions to or acquisitions of interests in persons; (xiv) determination of tax elections; (xv) certain matters with respect to the Series A Preferred Share (including exercise of the Preferred Share Call Right, consent to transfer and determination of fair market value); (xvi) matters related to the structure and composition of the Board; (xvii) adoption of a poison pill; (xviii) dissolution; (xix) amendment of our LLC Agreement; (xx) calling of shareholder meetings; (xxi) establishment of record dates; (xxii) approval of any merger, consolidation or conversion ; (xxiii) and any matters other than day-to-day general, administrative, or operational matters with respect to us and our subsidiaries.

Similarly, our LLC Agreement provides that certain matters require the approval of a majority of the Class B directors prior to the Fallaway Date, including, but not limited to: (i) certain refinancings of indebtedness; (ii) issuances of equity securities; (iii) exercise of the Preferred Share Call Right; (iv) non-ordinary course asset sales with expected proceeds of at least \$50 million; (v) the liquidation or dissolution of the Company or any of its material subsidiaries; (vi) acquisitions in excess of \$50 million; (vii) merger transactions involving the Company or Titan Operating; (viii) certain related party transactions; (ix) incurrence of indebtedness in excess of \$100 million or entering into certain types of financing transactions; and (x) the identification of disqualified lenders. In addition, the GSO-designated Class B director retains a veto right over certain refinancings of indebtedness and identification of disqualified lenders.

Director Independence

We have no securities listed for trading on a national securities exchange, but our Common Units are quoted on the OTCQX Market. As a result, we are not required to have a majority of independent directors, though the OTCQX Market does require that we have at least two. For purposes of complying with the disclosure, we have adopted the definitions of independence used by the OTC. Our Board has determined that each of Messrs. Davis, Zawadzki and Watchorn is independent under each of those definitions.

Committees of the Board of Directors

The standing committees of the Board currently are the Audit Committee and the Conflicts Committee.

Audit Committee

The Audit Committee's duties include recommending to the Board the independent public accountants to audit our financial statements and establishing the scope of, and overseeing, the annual audit. The Audit Committee also approves any other services provided by public accounting firms. The Audit Committee provides assistance to the Board in fulfilling its oversight responsibility to our shareholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor's qualifications and independence and the performance of internal audit function. The Audit Committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that our management and the Board have established. In doing so, it is the responsibility of the Audit Committee to maintain free and open communication between the committee and the independent auditors, internal accounting function and our management. In accordance with the Sarbanes-Oxley Act of 2002, the Audit Committee has adopted procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, and auditing matters and to allow for the confidential, anonymous submission by employees and others of concerns regarding questionable accounting or auditing matters. The Board has adopted a written charter for the Audit Committee.

The members of the Audit Committee are Messrs. Zawadzki and Watchorn. Mr. Watchorn is the chairman and has been determined by the Board to be an "audit committee financial expert," as defined by SEC rules.

Conflicts Committee

The principal functions of the Conflicts Committee are to review and approve transactions or arrangements with our management, Titan Management or ATLS, or other affiliates. The Conflicts Committee's responsibilities include: approving the allocation methodologies for general and administrative costs allocated to us by ATLS, as well as any changes to such allocations; approving new or additional compensation arrangements for named executive officers; approving the investment by Titan Management in any tax advantaged partnerships; approving any modifications, waivers or amendments of the Omnibus Agreement and the Delegation Agreement (each as defined below); and providing certain waivers under the tax matters agreement.

Prior to Fallaway Date, the Conflicts Committee will be comprised solely of Class B directors eligible to serve: Messrs. Zawadzki, Watchorn and Davis, with Mr. Davis acting as the chair.

The Board has not adopted a written charter for the Conflicts Committee, but the committee's primary responsibilities are set forth in our LLC Agreement.

Nominating and Governance Committee

On and after the Fallaway Date, the Nominating and Governance Committee will make the nominations for the election of Class B directors. The Board has not yet formed a standing Nominating and Governance Committee.

Compensation Committee Interlocks and Insider Participation

We do not maintain a standing compensation committee. As described above, our LLC Agreement provides that the Conflicts Committee is responsible for new or additional compensation arrangements for named executive officers. No members of the Conflicts Committee were an officer or employee of ours or any of our subsidiaries during fiscal 2015 or 2016 (to date) or was formerly an officer of ours. None of our executive officers has served on the board of directors or compensation committee of any entity that had one or more of its executive officers serving on our Board.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers and board members of our general partner and persons who beneficially own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the Securities and Exchange Commission and to furnish us with copies of all such reports.

Based solely upon our review of reports received by us, or representations from certain reporting persons that no filings were required for those persons, we believe that during fiscal year 2016 our executive officers, directors and persons who beneficially owned more than 10% of our common units complied with all applicable filing requirements, except that each of Messrs. Davis and Watchorn filed one late report relating to one transaction.

Code of Business Conduct and Ethics, Partnership Governance Guidelines and Committee Charters

We have adopted a charter for the Audit Committee. We will make a printed copy of our committee charters available to any shareholder who so requests. Requests for print copies may be directed to us as follows: Titan Energy, LLC, Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, Pennsylvania 15275-1011, Attention: Secretary. The committee charters are also posted on our website at www.titanenergyllc.com.

Following our emergence from bankruptcy, we have not yet adopted a code of business conduct and ethics that applies to our principal executive officer, principal financial officer and principal accounting officer, as well as to persons performing services for us generally or corporate governance guidelines, but we expect to do so in the near future as part of our ongoing corporate governance initiatives. Once adopted, we expect that the code of business conduct and ethics (as well as waivers therefrom) and corporate governance guidelines will be available to requesting shareholders and posted on our website in a manner similar to our committee charters.

ITEM 11: EXECUTIVE COMPENSATION COMPENSATION DISCUSSION AND ANALYSIS

For purposes of the following, the individuals listed below are collectively referred to as our “Named Executive Officers” or “NEOs.” The amounts of their compensation are disclosed in the tables following this discussion and analysis.

• Daniel C. Herz, our Chief Executive Officer;

- Jeffrey M. Slotterback, our Chief Financial Officer;

• Edward E. Cohen, our Executive Chairman of the Board;

• Jonathan Z. Cohen, our Executive Vice Chairman of the Board; and

• Mark D. Schumacher, our President.

Prior to September 1, 2016, Atlas Energy Group was the general partner of our predecessor. During that period, all compensation decisions related to our NEOs were determined by Atlas Energy Group’s Compensation Committee (the “Atlas Compensation Committee”). On September 1, 2016, on emergence from bankruptcy, we entered into an agreement with a wholly owned subsidiary of Atlas Energy Group, under which Atlas Energy Group, through its subsidiary, manages our business except for the Non-Delegated Duties set forth in our LLC Agreement.

As a result, we do not currently directly employ any persons to manage or operate our business (other than the employment agreements for certain of our NEOs, which are described in more detail below). These functions are provided by employees of Atlas Energy Group and/or its affiliates, pursuant to provisions of the Omnibus Agreement (the “Omnibus Agreement”) that we entered into on September 1, 2016. Under the Omnibus Agreement, we pay Atlas Energy Group’s expenses incurred in connection with its provision of services, subject to certain rights held by our Conflicts Committee relating to allocation methodologies for general and administrative costs.

Pursuant to the Omnibus Agreement, eighty percent of our NEOs’ compensation from Atlas Energy Group is paid by us and twenty percent is allocated to Atlas Energy Group and its subsidiaries. We do not have a separate

compensation committee. The Atlas Compensation Committee, and that committee's independent Compensation Consultant, have established the overall historical compensation structure for our NEOs (subject to the employment agreements for certain of the NEOs and the provisions of our LLC Agreement). Our Conflicts Committee has the right to approve "new or additional compensation agreements or arrangements" for our NEOs. Following September 1, 2016, the Conflicts Committee approved an increase in Mr. Slotterback's base salary.

To protect our rights and those of Atlas Energy Group and its key employees, pursuant to arrangements approved by the Bankruptcy Court, we entered directly into employment agreements with our Chief Executive Officer, Executive Chairman, Executive Vice Chairman, and President, as set forth below. In addition, our Chief Executive Officer, Executive Chairman, Executive Vice Chairman and President also have employment agreements with Atlas Energy Group. Additionally, we have made grants to our NEOs and to other employees under our Amended and Restated Management Incentive Plan.

The discussion below focuses on Atlas Energy Group's compensation philosophy, policies and practices. For 2016, the Atlas Compensation Committee recommended certain bonus payments for each of our NEOs. While the financial statements, compensation tables and compensation discussion reflect 2016 bonus amounts proposed by the Atlas Compensation Committee that exceed the Company guaranteed bonus amounts, such proposed bonus amounts in excess of the guaranteed amounts and any determination to pay such amounts all in cash instead of common stock have not received requisite Conflicts Committee approval and may not ultimately receive requisite approval in whole or in part.

Atlas Energy Group's Compensation Program Objectives

An understanding of Atlas Energy Group's executive compensation program begins with the following program objectives:

- **Aligning the interests of executives and unitholders.** The Atlas Compensation Committee seeks to align the interests of our executives with those of our unitholders through equity-based compensation and executive unit ownership requirements.

- **Linking rewards to performance.** The Atlas Compensation Committee seeks to implement a pay-for-performance philosophy by tying a significant portion of executives' compensation to their achievement of goals that are linked to our business strategy and each executive's contributions towards the achievement of those goals.

- **Offering competitive compensation.** The Atlas Compensation Committee seeks to offer an executive compensation program that is competitive and that helps attract, motivate and retain top performing executives.

The Atlas Compensation Committee believes that a significant portion of executive compensation should be variable and based on defined performance goals (i.e., "at risk"). The executive compensation program meets this objective by delivering compensation in the form of equity and other performance-based awards.

Governance of Atlas Energy Executive Compensation

Atlas Compensation Committee

The Atlas Compensation Committee is comprised solely of independent directors of the Atlas Energy Group board. The Atlas Compensation Committee is responsible for designing the compensation objectives and methodology, and evaluating the compensation to be paid to Atlas Energy's executives, and making recommendations with respect to our NEOs. The Atlas Compensation Committee is also responsible for administering Atlas Energy Group's stock ownership guidelines and certain employee benefit plans, including incentive plans.

Chief Executive Officer

The Atlas Energy Group Chief Executive Officer makes recommendations to the Atlas Compensation Committee regarding the salary, bonus and incentive compensation component of each of the other NEO's total compensation from Atlas Energy Group. The Atlas Energy Group Chief Executive Officer provides the Atlas Compensation Committee with key elements of organizational and individual performance during the year or the applicable performance period to assist the committee in its determinations. The Atlas Energy Group Chief Executive Officer, at the Atlas Compensation Committee's request, might attend committee meetings to provide insight into our NEOs' performance, as well as the performance of other comparable companies in the same industry. The Atlas Compensation Committee determines and approves the Atlas Energy Group Chief Executive Officer's compensation based upon its evaluation of his performance.

Independent Compensation Consultant

Since 2015, the Atlas Compensation Committee has engaged Mercer (US) Inc., a global compensation and benefits consulting firm and wholly-owned subsidiary of Marsh & McLennan Companies, Inc. (“Marsh”), to provide information and objective advice regarding executive compensation.

A critical criterion in the Atlas Compensation Committee’s selection of Mercer to provide executive and director compensation consulting services was that Mercer does not provide any other executive compensation consulting services to Atlas Energy Group or its affiliated companies, including us, other than insurance brokerage services provided by its parent company, Marsh. Atlas Energy Group, its directors and our executive officers are also required to complete questionnaires on an annual basis, which allows Atlas Energy Group and its subsidiaries, including us, to review whether there are any potential conflicts as a result of personal or business relationships. There were no business or personal relationships between the consultants from Mercer who work with us, Atlas Energy Group’s directors and our executive officers other than the executive compensation consulting described herein. The Atlas Compensation Committee also determined that the reporting relationship and the compensation of Mercer were separate from, and not determined by reference to, Mercer’s or Marsh’s other lines of business or any other work for Atlas Energy Group and us. Further, the Atlas Compensation Committee is aware that in the ordinary course of business we, Atlas Energy Group and its affiliates use Marsh’s insurance broker services, but it does not monitor or approve those services.

Elements of Atlas Energy Group's Compensation Program

Base Salary

Base salary is intended to provide fixed compensation to the NEOs for their performance of core duties that contribute to our success. Base salaries represent one component of our compensation strategy and are not contingent upon the achievement of performance metrics and/or intended to compensate individuals for performance which exceeds expectations.

Annual Incentives

Annual incentives are intended to tie a significant portion of each of the NEO's compensation to Atlas Energy Group's annual performance. Generally, the higher the level of responsibility of the executive within Atlas Energy Group, the greater is the incentive component of that executive's target total cash compensation. The Atlas Compensation Committee may recommend awards of performance-based variable pay and, on rare occasions, discretionary bonuses.

Atlas Energy Group has an Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, to award pay for achievement of predetermined performance measurements during a performance period. The applicable performance period is the current fiscal year. During the 2016 performance period, each of the NEOs participated in the Senior Executive Plan. Awards under the Senior Executive Plan may be paid in cash or in a combination of cash and time-vesting equity.

As soon as was practicable, the Atlas Compensation Committee approved the performance measurements for the 2016 performance period. In recognizing current circumstances with respect to the energy industry, the Atlas Compensation Committee adopted a performance formula that would be evaluated by the Atlas Compensation Committee on a quarterly basis with respect to each NEO. The Committee determined that the most critical measurement, which was to be given the greatest weight, was the performance with respect to negotiating with stakeholders including, but not limited to: bond holders, second lienholders, banks, other lenders, vendors, service providers and other general creditors; and other persons or entities who are or may be operationally, financially or strategically important to the Company. In addition to the aforementioned measurement, the Committee would also evaluate each NEO's performance in connection with his regular and normal responsibilities, consistent with his position and past practice, including but not limited to cost control operationally and/or administratively, financial performance of Atlas Energy Group during the period, private channel fund raise, hedge position values, production margin performance and environmental performance.

Pursuant to the Senior Executive Plan, the Atlas Compensation Committee had discretion to recommend awards up to the maximum amount. The maximum award allocable to us for each participant was as follows: Mr. E. Cohen, \$1,280,000; Mr. J. Cohen, \$960,000; Mr. Herz, \$960,000; Mr. Schumacher, \$800,000; and Mr. Slotterback, \$640,000. As discussed in greater detail below, none of the NEOs received above 71% of the maximum award.

Exceptional Bonuses

In exceptional circumstances, additional bonuses may be awarded to recognize individual and group performance without regard to limitations otherwise in effect. Other than Mr. Slotterback, who received a retention bonus in April 2016, the Atlas Compensation Committee did not award any additional bonuses with respect to Atlas Energy Group's performance for the applicable performance period.

Long-Term Incentives

The Atlas Compensation Committee believes that Atlas Energy Group's and our long-term success depends upon aligning its and our executives' and unitholders' interests. To support this objective, Atlas Energy Group provides our executives with the ability to become significant equity holders via awards under the Titan Energy LLC Management Incentive Plan, as amended (the "MIP"). However, our Board determines the awards to our NEOs under the MIP.

Our NEOs also are eligible to receive awards under the Atlas Energy Group 2015 Long-Term Incentive Plan, which we refer to as the Atlas Energy Group Plan. Under the Atlas Energy Group Plan, the Atlas Compensation Committee may recommend grants of equity awards in the form of options and/or phantom units. Generally, the unit options and phantom units vest over a three- or four-year period.

Additional Information Concerning Executive Compensation

Deferred Compensation

All of Atlas Energy Group's employees may participate in its 401(k) plan, which is a qualified defined contribution plan designed to help participating employees accumulate funds for retirement. This plan was originally known as the Atlas Energy 401(k) Plan and was assumed by Atlas Energy Group in connection with the Separation. In February 2015, Atlas Energy Group also assumed the Atlas Energy Executive Excess 401(k) Plan (currently known as the "Deferred Compensation Plan"), a nonqualified deferred compensation plan that was designed to permit individuals who exceeded certain income thresholds as established by the IRS and who might be subject to compensation and/or contribution limitations under what was then the Atlas Energy 401(k) plan and is now the Atlas Energy Group 401(k) Plan to defer an additional portion of their compensation. The purpose of the Deferred Compensation Plan is to provide participants with an incentive for a long-term career with Atlas Energy Group by providing them

with an appropriate level of replacement income upon retirement. Under the Deferred Compensation Plan, a participant was permitted to contribute to an account an amount up to 10% of annual cash compensation (which means a participant's salary and non-performance-based bonus) and up to 100% of all performance-based bonuses. Atlas Energy Group is obligated to make matching contributions on a dollar-for-dollar basis of the amount deferred by the participant subject to a maximum matching contribution equal to 50% of the participant's base salary for any calendar year. Atlas Energy Group does not pay above-market or preferential earnings on deferred compensation. Participation in the Deferred Compensation Plan is available pursuant to the terms of an individual's employment agreement or at the designation of the Atlas Compensation Committee. During 2016, Messrs. E. Cohen and J. Cohen were the only participants in the Deferred Compensation Plan. For further details, please see "2016 Nonqualified Deferred Compensation" table. A portion of both the deferred amounts and the matching contributions are allocated to us.

No Hedging of Company Stock

All of Atlas Energy Group's employees (including our NEOs) are prohibited from hedging their company stock.

No Tax Gross-Ups

Neither we nor Atlas Energy Group provide tax reimbursements to our NEOs.

Perquisites

At the discretion of the Atlas Compensation Committee, Atlas Energy Group provided perquisites to our NEOs. In 2016, the benefits provided to the NEOs were limited to providing automobile allowances or automobile-related expenses to Messrs. E. Cohen, Herz and Schumacher.

Determination of 2016 Compensation Amounts

Given the transformative events of the 2016 fiscal year, the determination of the components of the 2016 compensation amounts for our NEOs took place over different times during the year. Early in 2016, at the same time that it evaluated our NEOs' performance under the metrics that had been established pursuant to the Senior Executive Plan, the Atlas Compensation Committee adjusted the base salaries of Messrs. E. Cohen and J. Cohen to levels that were at the median of, and Mr. Herz to a level that was competitive with, the peer group that had been approved by the board and from which Mercer had developed a competitive market assessment.

The Atlas Compensation Committee consulted with Mercer over the course of the rest of 2016 with respect to retention bonuses for various senior officers including Mr. Slotterback, developing the 2016 performance metrics under the Senior Executive Plan and, in consultation with our Conflicts Committee, increasing Mr. Slotterback's base salary.

Because the 2016 performance metrics were analyzed on a periodic basis, in July 2016 and then again in February and March 2017, the Atlas Compensation Committee consulted with Mercer, with Atlas Energy Group's Chief Executive Officer participating, to evaluate Atlas Energy Group's and our performance and to approve short-term incentive awards to NEOs. In July 2016, prior to our bankruptcy proceedings, the Atlas Compensation Committee approved short-term incentive awards for the first two quarters of 2016. In February 2017, the Atlas Compensation Committee prepared to evaluate the NEOs' performance under the Senior Executive Plan with respect to the last two quarters of 2016.

Base Salary

In January 2016, the Atlas Compensation Committee engaged Mercer to conduct an analysis of historical short-term incentives and benchmarking of base salaries of all of our NEOs using a market competitive assessment against a peer group of then-comparable energy companies (the “2015 peer group”). The Atlas Compensation Committee considered the analysis and benchmarking and approved increases to Messrs. E. Cohen and J. Cohen’s base salaries to \$700,000 and \$500,000, respectively, bringing out their base salaries to the median of the 2015 peer group. The Atlas Compensation Committee recognized the further increased role that Mr. Herz had undertaken in challenging times and approved an increase in his 2016 base salary to \$500,000, an amount that was competitive with the 2015 peer group. The Atlas Compensation Committee maintained the base salaries of Messrs. Slotterback and Schumacher at 2015 levels. Mr. Slotterback’s base salary was below the median of the peer group and Mr. Schumacher’s base salary being competitive with the median. In October 2016, however, upon further consultation with Mercer, and based upon benchmarking against the 2015 peer group as well as against an executive remuneration survey for the oil and gas industry, the Atlas Compensation Committee recommended to the Conflicts Committee, and the Conflicts Committee subsequently approved, the increase to \$350,000 for Mr. Slotterback.

In February 2017, the Atlas Compensation Committee did not recommend to the Conflicts Committee any adjustments to the 2017 base salaries of the NEOs.

The 2016 amounts reflected in the Summary Compensation Table reflect the amount of each NEOs’ base salary prior to allocation to us.

Annual Incentives

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Following the first half of the 2016 fiscal year and after the end of the 2016 fiscal year, the Atlas Compensation Committee considered incentive awards pursuant to the Senior Executive Plan based on performance during the 2016 performance period. In determining the actual amounts to be paid to the NEOs, the Atlas Compensation Committee considered both individual and company performance. The Atlas Energy Group Chief Executive Officer made recommendations of incentive award amounts based upon Atlas Energy Group's performance as well as the performance of its subsidiaries, including our performance; however, the Atlas Compensation Committee had the discretion to approve, reject or modify the recommendations. Further, the Committee had the discretion to reduce, but not increase, the maximum awards available under the Senior Executive Plan.

The Atlas Compensation Committee noted that although 2015 was a difficult year for the oil and gas industry, 2016 was no better. However, Atlas Energy Group and our management had demonstrated their ability to navigate the continuing challenging market conditions. The Atlas Compensation Committee recognized that, in the face of these significant challenges, the NEOs experienced great success in dealing with stakeholders during the past year. At the beginning of 2016, our Predecessor and Atlas Energy Group were facing significant liquidity issues. By year-end 2016, the NEOs continued to manage these crises through negotiations involving virtually all stakeholder interests.

In evaluating the 2016 performance measurements, the Atlas Compensation Committee focused and gave great weight to the NEOs' efforts, progress and success in negotiating with the many stakeholders. The Committee commended the NEOs for successfully securing agreement amongst Atlas Energy Group's lenders for a restructuring that substantially reduced cash interest expense and markedly increased covenant compliance. Even more importantly, perhaps, our creditors were persuaded (without any payment of any kind from Atlas Energy Group) to release all claims against Atlas Energy Group as general partner of our Predecessor. Our NEOs were also able to preserve Atlas Energy Group's 2% preferred ownership interest in us and significant control over our ongoing operations.

The Atlas Compensation Committee also commended the NEOs' skill in effectuating in 2016 one of the quickest in-court restructurings ever achieved in the energy sector, working successfully with our 23 banks, two second lien holders, and 99% (by face value) of the principal holders of our unsecured notes. All these stakeholders supported our plan of reorganization, resulting in our birth, over which our NEOs continue to exercise control.

In addition to evaluating the NEOs' performance in dealing with stakeholders, the Atlas Compensation Committee also evaluated the NEOs' performance with respect to their regular and normal responsibilities. The Atlas Compensation Committee noted that management had reduced general and administrative expense of the business from \$81.3 million in 2015 to approximately \$49.3 million in 2016. Noting that despite management's success in effectuating such cuts and reductions, environment, health and safety compliance actually improved in 2016 as compared to 2015, although the number of operated wells across Atlas Energy Group had remained approximately constant. The Atlas Compensation Committee noted that Atlas Energy Group experienced a lower incident rate and fewer reportable spills in 2016 as compared to 2015. Management's hedging activities provided approximately \$216 million in net proceeds toward repayment of our first lien credit facility. On an unhedged basis, during the fourth quarter of 2016 (the first full quarter subsequent to emergence), we realized unhedged gross margin of \$1.80 per mcf compared with \$0.69 for the comparable quarter in 2015. This improvement reflected our management's ability to expand oil production (with its superior margins) as against our traditional natural gas business (with its disappointing gross margins).

The Atlas Compensation Committee took both our overall performance during the year together with the achievement of the performance measurements and, while recognizing the strong performance during challenging times, ultimately awarded short-term incentive awards that were below the maximum potential awards for each of the NEOs as follows: Mr. E. Cohen, 59% of maximum potential award, Mr. J. Cohen, 71% of maximum potential award, Mr. Herz, 71% of maximum potential award, Mr. Schumacher, 59% of maximum potential award; and Mr. Slotterback, 67% of maximum potential award.

Long-Term Incentives

In an effort to maintain critical continuity of our proven NEOs and senior management team during a highly challenging environment, in October 2016, the Atlas Compensation Committee granted Atlas Energy Group phantom units to all of its employees and to the NEOs as follows: Mr. E. Cohen—200,000 phantom units; Mr. J. Cohen—200,000 phantom units; Mr. Herz—200,000 phantom units; Mr. Schumacher—100,000 phantom units; and Mr. Slotterback—100,000 phantom units. These awards are to vest one-third on each anniversary of the grant. The Atlas Compensation Committee recognized that such continuity grants were critical to retention of executives and other employees even in a “soft” energy market.

None of the costs of the Atlas Energy Group phantom units granted to the NEOs and other employees of the Company are allocated to us or are reflected in our financial statements.

SUMMARY COMPENSATION TABLE

Name	Year	Salary (\$)	Bonus (\$) ⁽¹⁾	Stock awards (\$) ⁽²⁾	Option awards (\$) ⁽³⁾	Non-equity incentive plan compensation (\$) ⁽¹⁾	All other compensation (\$)	Total (\$)
Daniel C. Herz	2016	495,384		869,555		680,000	7,680 ⁽⁴⁾	2,052,619
	2015	292,115		1,607,500		700,000	143,195 ⁽⁵⁾	2,678,195
	2014	266,000	225,000	4,869,769			509,621	5,724,390
Jeffrey M. Slotterback	2016	280,192	240,000	367,835		430,000	75 ⁽⁶⁾	1,262,064
	2015	143,769		225,050		210,000	11,315 ⁽⁷⁾	590,134
Edward E. Cohen	2016	689,231		869,555		760,000	120,709 ⁽⁸⁾	2,439,494
	2015	332,500		1,607,500		210,000	715,799 ⁽⁹⁾	2,865,799
	2014	380,000		15,583,198		760,000	1,815,584	18,538,782
Jonathan Z. Cohen	2016	495,384		869,555		680,000	256,992 ⁽¹⁰⁾	2,301,931
	2015	292,115		1,607,500		175,000	780,869 ⁽¹¹⁾	2,855,484
	2014	266,000		15,083,221		760,000	1,591,764	17,700,985
Mark D. Schumacher	2016	375,000		367,835		470,000	10,071 ⁽¹²⁾	1,222,906
	2015	262,500		1,125,250		350,000	127,833 ⁽¹³⁾	1,865,583

(1) The 2016 bonus amounts proposed by the Atlas Compensation Committee that exceed the Company guaranteed bonus amounts and any determination to pay such amounts all in cash instead of common stock have not received requisite Conflicts Committee approval and may not ultimately receive requisite approval in whole or in part.

(2) For fiscal year 2016, the amounts reflect the grant date fair value of the phantom units under the Atlas Energy Group Plan and the grant date fair value of the common shares under the Titan Plan. The compensation expense associated with the phantom units under the Atlas Energy Group was not allocated to us, but a portion of that compensation was intended to reflect our NEOs service to us on behalf of Atlas Energy Group. The grant date fair value was determined in accordance with FASB ASC Topic 718 and is based on the market value on the grant date of Atlas Energy Group units and Titan stock. See “Compensation Discussion & Analysis—Determination of 2016 Compensation Amounts—Long-Term Incentives.” For fiscal year 2015, the amounts reflect the grant date fair value of the phantom units under the Atlas Energy Group Plan. The grant date fair value was determined in accordance with FASB ASC Topic 718 and is based on the market value on the grant date of Atlas Energy Group units. For fiscal year 2014, the amounts reflect the grant date fair value of the phantom units under the Atlas Energy Group Plan. The grant date fair value was determined in accordance with FASB ASC Topic 718 and is based on the market value on the grant date of Atlas Energy units.

(3) The amounts in this column reflect the grant date fair value of options awarded under the Atlas Resource Partners Plan (the “ARP Plan”) calculated in accordance with FASB ASC Topic 718.

(4) Represents our allocated portion of an automobile allowance.

(5)

- Comprised of (i) payments on DERs of \$122,713 with respect to the phantom units awarded under the Atlas Energy Plans, (ii) payments on DERs of \$13,762 with respect to the phantom units awarded under the ARP Plan, and (iii) our allocated portion of an automobile allowance.
- (6) Represents payments on DERs of \$75 with respect to the phantom units awarded under the ARP Plan.
- (7) Comprised of (i) payments on DERs of \$8,168 with respect to the phantom units awarded under the Atlas Energy Plans and (ii) payments on DERs of \$3,148 with respect to the phantom units awarded under the ARP Plan.
- (8) Includes our allocated portion of the matching contribution of \$148,077 under the Atlas Energy Deferred Compensation Plan and our allocated portion of tax, title and insurance premiums for Mr. E. Cohen's automobile.
- (9) Comprised of (i) payments on DERs of \$317,237 with respect to the phantom units awarded under the Atlas Energy Plans, (ii) payments on DERs of \$29,490 with respect to the phantom units awarded under the ARP Plan, (iii) our allocated portion of a matching contribution of \$524,423 under the Atlas Energy Deferred Compensation Plan, (iv) our allocated portion of tax, title and insurance premiums for Mr. E. Cohen's automobile.
- (10) Comprised of (i) our allocated portion of the matching contribution of \$ 133,846 under the Atlas Energy Deferred Compensation Plan, and (ii) our allocated portion of 187,393 paid under the agreement relating to Lightfoot.
- (11) Comprised of (i) payments on DERs of \$289,181 with respect to the phantom units awarded under the Atlas Energy Plans, (ii) payments on DERs of \$29,490 with respect to the phantom units awarded under the ARP Plan, (iii) payments on DERs of \$100,800 with respect to the phantom units awarded under the APL Plans, (iv) our allocated portion of a matching contribution of \$ 375,577 under the Atlas Energy Deferred Compensation Plan, and (v) 284,707 paid under the agreement relating to Lightfoot.
- (12) Comprised of (i) payments on DERs of \$2,390 with respect to the phantom units awarded under the ARP Plan, and (ii) our allocated portion of an automobile allowance.
- (13) Comprised of (i) payments on DERs of \$24,858 with respect to the phantom units awarded under the Atlas Energy Plans, (ii) payments on DERs of \$96,255 with respect to the phantom units awarded under the ARP Plan; and (iii) our allocated portion of an automobile allowance.

2016 GRANTS OF PLAN-BASED AWARDS

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Name	Estimated possible payments under non-equity incentive plan awards ⁽¹⁾			Grant Date	All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Under-lying Options	Exercise of Base Price of Option Awards (\$/Sh)	Grant Date Fair Value of Unit and Option Awards ⁽⁴⁾
	Threshold (\$)	Target (\$)	Maximum (\$)					
Daniel C. Herz	N/A	N/A	\$1,200,000	10/6/2016	200,000 ⁽²⁾	-	-	\$334,000
				9/1/2016	111,111 ⁽³⁾	-	-	\$535,555
Jeffrey M. Slotterback	N/A	N/A	\$800,000	10/6/2016	100,000 ⁽²⁾	-	-	\$167,000
				9/1/2016	41,667 ⁽³⁾	-	-	\$200,834
Edward E. Cohen	N/A	N/A	\$1,600,000	10/6/2016	200,000 ⁽²⁾	-	-	\$334,000
				9/1/2016	111,111 ⁽³⁾	-	-	\$535,555
Jonathan Z. Cohen	N/A	N/A	\$1,200,000	10/6/2016	200,000 ⁽²⁾	-	-	\$334,000
				9/1/2016	111,111 ⁽³⁾	-	-	\$535,555
Mark D. Schumacher	N/A	N/A	\$1,000,000	10/6/2016	100,000 ⁽²⁾	-	-	\$167,000
				9/1/2016	41,667 ⁽³⁾	-	-	\$200,834

(1) Represents performance-based bonuses under Atlas Energy Group's Senior Executive Plan that may be paid in cash and/or equity. As discussed under "Compensation Discussion and Analysis—Elements of Atlas Energy Group's Compensation Program—Annual Incentives," the Atlas Compensation Committee set performance measurements for the NEOs. The Atlas Compensation Committee did not award any equity awards under the Senior Executive Plan.

(2) Represents phantom units granted under the Atlas Energy Group Plan. None of the costs of the Atlas Energy Group phantom units granted to the NEOs and other employees of the Company are allocated to us or are reflected in our financial statements.

(3) Represents restricted and unrestricted shares granted under the 2016 Titan Management Incentive Plan.

(4) The grant date fair value was calculated in accordance with FASB ASC Topic 718.

Employment Agreements and Potential Payments Upon Termination or Change of Control

We and Atlas Energy Group have employment agreements with certain of our NEOs that provide for severance compensation to be paid if such NEO's employment is terminated under certain conditions.

Atlas Energy Group Employment Agreements

Effective September 4, 2015, our Predecessor and Atlas Energy Group entered into an employment agreement with each of Edward E. Cohen, Atlas Energy Group's Chief Executive Officer, Jonathan Z. Cohen, Atlas Energy Group's Executive Chairman of the board of directors, Daniel C. Herz, Atlas Energy Group's President, and Mark Schumacher,

Atlas Energy Group's Senior Vice President (collectively, the "Atlas Employment Agreements").

The Atlas Employment Agreements with Messrs. E. Cohen and J. Cohen each provide for a term of three years (which automatically renews daily unless earlier terminated) and an initial base salary of \$350,000, subject to periodic increases by the Atlas Compensation Committee. The Atlas Employment Agreements with Messrs. Herz and Schumacher each provide for a term of two years (which automatically renews daily for one-year terms after the first anniversary of the effective date of the agreement unless earlier terminated) and an initial base salary of \$350,000 (in the case of Mr. Herz) and \$375,000 (in the case of Mr. Schumacher), subject to increases, but not decreases, by the Atlas Compensation Committee.

Under the Atlas Employment Agreements, Messrs. E. Cohen and J. Cohen are entitled to receive cash and non-cash bonus compensation in such amounts as the Atlas Energy Group board or the Atlas Compensation Committee may approve or under the terms of any incentive plan that we maintain for the Atlas Energy Group senior level executives. Atlas Energy Group is required to maintain a term life insurance policy for each of Mr. E. Cohen's and Mr. J. Cohen's respective lives that each separate policy provide a death benefit of \$3 million to one or more beneficiaries designated by Messrs. E. Cohen and J. Cohen respectively, which such policy, at each individual's request, can be assumed by such individual upon a termination of employment, if and as allowed by the applicable insurance company.

Pursuant to the Atlas Employment Agreements, Messrs. Herz and Schumacher are each entitled to receive a bonus determined in accordance with procedures established by Atlas Energy Group's board or the Atlas Compensation Committee. In addition Messrs. Herz and Schumacher are each eligible to receive grants of equity-based compensation as determined by Atlas Energy Group's board or the Atlas Compensation Committee.

Under the Atlas Employment Agreements, if the executive is terminated without cause or resigns with good reason, then, subject to his execution and non-revocation of a release of claims in favor of us and related parties, the executive will be entitled to receive (a) two times (or three times in the case of Messrs. E. Cohen and J. Cohen) the sum of the executive's base salary plus his average incentive compensation for the previous three years (or such lesser period as applicable), (b) a pro rata cash bonus for the year of termination, (c) 24 months of continued health insurance (or 36 months in the case of Messrs. E. Cohen and J. Cohen of continued health and life insurance), and (d) accelerated vesting of all equity-based compensation.

Pursuant to the Atlas Employment Agreements, in the event of death, Messrs. E. Cohen and J. Cohen are each entitled to receive (a) a pro rata cash bonus for the year of termination and (b) accelerated vesting of all equity-based compensation. Under the Atlas Employment Agreements, in the event of disability, Messrs. E. Cohen and J. Cohen are each entitled to receive (a) a pro rata cash bonus for the year of termination, (b) 36 months of life and health insurance, and (c) accelerated vesting of all equity-based compensation.

Under the Atlas Employment Agreements, in the event of death or disability, Messrs. Herz and Schumacher are each entitled to receive (a) a pro rata cash bonus for the year of termination, (b) 12 months of continued health insurance for the executive and his dependents, and (c) accelerated vesting of all equity-based compensation.

In addition, the Atlas Employment Agreements each contain certain restrictive covenants, including (a) in the case of Messrs. E. Cohen and J. Cohen, a 12 month post termination noncompetition covenant and 24 month post termination nonsolicitation covenant if the executive is terminated with cause or resigns without good reason, (b) in the case of Mr. Herz an 18 month post termination noncompetition covenant and a 24 month post termination nonsolicitation covenant if the executive is terminated without cause or resigns without good reason, and (c) in the case of Mr. Schumacher, an 18 month post termination noncompetition covenant and 24 month post termination nonsolicitation covenant, if prior to a change in control or after the first anniversary of a change in control, the executive is terminated with cause or resigns without good reason, or within one year following a change in control, the executive's employment terminates for any reason.

Under each of the Atlas Employment Agreements, any payments or benefits payable to the executive will be cutback to the extent that such payments or benefits would result in the imposition of excise taxes under Section 4999 of the Internal Revenue Code, unless the executive would be better off on an after-tax basis receiving all such payments or benefits.

The following table provides an estimate of the value of the benefits to Mr. E. Cohen pursuant to his Atlas Employment Agreement, if a termination event had occurred as of December 31, 2016.

Reason for termination	Lump sum severance payment	Accelerated vesting of unit awards and option awards ⁽²⁾ Benefits ⁽¹⁾	
Death	\$4,776,712 ⁽³⁾	\$—	\$681,215
Disability	1,776,712	37,000	681,215
Termination by Atlas Energy Group without cause or by Mr. Cohen for good reason	9,541,780 ⁽⁴⁾	37,000	681,215

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1) Dental and medical benefits were calculated using 2016 COBRA rates.

(2) Represents the value of unvested unit awards disclosed in the "2016 Outstanding Equity Awards at Fiscal Year-End" table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3) Represents pro rata incentive compensation and life insurance policy proceeds.

(4) Represents pro rata incentive compensation plus three times (a) Mr. Cohen's base salary plus (b) average incentive compensation.

The following table provides an estimate of the value of the benefits to Mr. J. Cohen pursuant to his Atlas Employment Agreement, if a termination event had occurred as of December 31, 2016.

Reason for termination	Benefits ⁽¹⁾
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	Lump sum severance payment		Accelerated vesting of unit awards and option awards ⁽²⁾
Death	\$4,776,712 ⁽³⁾	\$—	\$681,215
Disability	1,726,712	66,718	681,215
Termination by Atlas Energy Group without cause or by Mr. Cohen for good reason	8,816,780 ⁽⁴⁾	66,718	681,215

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1) Dental and medical benefits were calculated using 2016 COBRA rates.

(2) Represents the value of unvested unit awards disclosed in the “2016 Outstanding Equity Awards at Fiscal Year-End” table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3) Represents pro rata incentive compensation and life insurance policy proceeds.

(4) Represents pro rata incentive compensation plus three times (a) Mr. Cohen’s base salary plus (b) average incentive compensation.

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The following table provides an estimate of the value of the benefits to Mr. Herz pursuant to his Atlas Employment Agreement, if a termination event had occurred as of December 31, 2016.

Reason for termination	Lump sum severance payment	Benefits ⁽¹⁾	Accelerated vesting of unit awards and option awards ⁽²⁾
Death	\$1,582,740	22,144	\$681,215
Disability	1,582,740	22,144	681,215
Termination by Atlas Energy Group without cause or by Mr. Herz for good reason	4,915,480 ⁽³⁾	44,288	681,215

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1)Dental and medical benefits were calculated using 2016 COBRA rates.

(2)Represents the value of unvested unit awards disclosed in the “2016 Outstanding Equity Awards at Fiscal Year-End” table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3)Represents two times (a) Mr. Herz’s base salary plus (b) average incentive compensation.

The following table provides an estimate of the value of the benefits to Mr. Schumacher, pursuant to his Atlas Employment Agreement, if a termination event had occurred as of December 31, 2016:

Reason for termination	Lump sum severance payment	Benefits ⁽¹⁾	Accelerated vesting of unit awards and option awards ⁽²⁾
Death	\$500,000	\$22,239	\$331,957
Disability	500,000	22,239	331,957
Termination by Atlas Energy Group without cause or by Mr. Schumacher for good reason	2,012,500 ⁽³⁾	\$44,479	331,957

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1)Dental and medical benefits were calculated using 2016 COBRA rates.

(2)Represents the value of unvested unit awards disclosed in the “2016 Outstanding Equity Awards at Fiscal Year-End” table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3)Represents two times (a) Mr. Schumacher’s base salary plus (b) average incentive compensation.

Titan Employment Agreements

On September 1, 2016, we and Titan Operating entered into employment agreements with each of Messrs. E. Cohen, our Executive Chairman, J. Cohen, our Executive Vice Chairman, Herz, our Chief Executive Officer, and Schumacher, our President (collectively, the “Titan Employment Agreements”). The Titan Employment Agreements and compensation thereunder are not intended to duplicate that provided under the Atlas Employment Agreements.

The Titan Employment Agreements for Messrs. E. Cohen and J. Cohen each have an initial term of three years and the Titan Employment Agreements for Messrs. Herz and Schumacher each have an initial term of two years, in each case subject to early termination under certain circumstances. Each of the Titan Employment Agreements contain automatic daily extensions of the term; the term of the Titan Employment Agreements for Messrs. E. Cohen and J. Cohen are extended by one day each day so that the remaining term remains at three years and the term of the Titan Employment Agreements for Messrs. Herz and Schumacher are also extended for an additional day on a daily basis

commencing on September 1, 2017 (unless, in the case of Messrs. Herz and Schumacher, Titan Energy gives written notice to the executive following September 1, 2017 that the term will not be so extended). Under the Titan Employment Agreements, the annual base salaries, prior to allocation to us, for each of Messrs. E. Cohen, J. Cohen, Herz and Schumacher are \$700,000, \$500,000, \$500,000 and \$375,000, respectively, and for each of 2016 and 2017 each executive will receive an annual bonus of at least 100% of his annual salary, payable in a combination of cash and equity (subject to certain restrictions regarding the composition of the bonus, as set forth in the Titan Employment Agreements). Atlas Energy Group is required to maintain a term life insurance policy for each of Mr. E. Cohen's and Mr. J. Cohen's respective lives that each separate policy provide a death benefit of \$3 million to one or more beneficiaries designated by Messrs. E. Cohen and J. Cohen respectively, which such policy, at each individual's request, can be assumed by such individual upon a termination of employment, if and as allowed by the applicable insurance company.

Under the Titan Employment Agreements, if the executive is terminated without cause or resigns with good reason, then, subject to his execution and non-revocation of a release of claims in favor of Atlas Energy Group and related parties, the executive

will be entitled to receive (a) two times (or three times in the case of Messrs. E. Cohen and J. Cohen) the sum of the executive's base salary plus his average incentive compensation for the previous two years, (b) a pro rata cash bonus for the year of termination, (c) 24 months of continued health insurance (or 36 months in the case of Messrs. E. Cohen and J. Cohen of continued health and life insurance), and (d) accelerated vesting of all equity-based compensation. In addition, if Messrs. E. Cohen or J. Cohen is terminated without cause or resigns in good reason in connection with a change in control, then the severance payable in (a) as stated above shall not exceed an amount equal to \$5,000,000 reduced by the fair market value as of the date of such change in control of any unvested equity awards held by Messrs. E. Cohen and J. Cohen, but in no event shall such amount of severance payable in (a) be reduced below \$2,000,000.

The Titan Employment Agreements contain the same death and disability provisions for the executives as outlined above in the summary of the death and disability provisions of the Atlas Employment Agreements.

Each of the Titan Employment Agreements contains restrictive covenants applicable to the executive officers with respect to noncompetition and nonsolicitation that are similar to such provisions in the Atlas Employment Agreements.

In addition, under each of the Titan Employment Agreements, any payments or benefits payable to the executive will be cutback to the extent that such payments or benefits would result in the imposition of excise taxes under Section 4999 of the Internal Revenue Code, unless the executive would be better off on an after-tax basis receiving all such payments or benefits.

The following table provides an estimate of the value of the benefits to Mr. E. Cohen pursuant to his Titan Employment Agreement, if a termination event had occurred as of December 31, 2016.

Reason for termination	Lump sum severance payment	Benefits ⁽¹⁾	Accelerated vesting of unit awards and option awards ⁽²⁾
Death	\$3,821,370 ⁽³⁾	\$—	\$357,215
Disability	1,421,370	29,600	357,215
Termination by us without cause or by Mr. Cohen for good reason	7,633,424 ⁽⁴⁾	29,600	357,215
Termination upon a change of control	4,642,785		357,215

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1)Dental and medical benefits were calculated using 2016 COBRA rates.

(2)Represents the value of unvested unit awards disclosed in the "2016 Outstanding Equity Awards at Fiscal Year-End" table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3)Represents pro rata incentive compensation and life insurance policy proceeds allocated to Titan.

(4)Represents pro rata incentive compensation plus three times (a) Mr. Cohen's base salary plus (b) average incentive compensation allocated to Titan.

The following table provides an estimate of the value of the benefits to Mr. J. Cohen pursuant to his Titan Employment Agreement, if a termination event had occurred as of December 31, 2016.

Reason for termination	Benefits ⁽¹⁾
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	Lump sum severance payment		Accelerated vesting of unit awards and option awards ⁽²⁾
Death	\$3,781,370 ⁽³⁾	\$—	\$357,215
Disability	1,381,370	53,374	357,215
Termination by us without cause or by Mr. Cohen for good reason	7,053,424 ⁽⁴⁾	53,374	357,215
Termination upon a change of control	4,642,785		357,215

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1)Dental and medical benefits were calculated using 2016 COBRA rates.

(2)Represents the value of unvested unit awards disclosed in the “2016 Outstanding Equity Awards at Fiscal Year-End” table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3)Represents pro rata incentive compensation and life insurance policy proceeds allocated to Titan.

(4)Represents pro rata incentive compensation plus three times (a) Mr. Cohen’s base salary plus (b) average incentive compensation allocated to Titan.

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The following table provides an estimate of the value of the benefits to Mr. Herz pursuant to his Titan Employment Agreement, if a termination event had occurred as of December 31, 2016.

Reason for termination	Lump sum severance payment	Benefits ⁽¹⁾	Accelerated vesting of unit awards and option awards ⁽²⁾
Death	\$1,266,192	17,715	\$357,215
Disability	1,266,192	17,715	357,215
Termination by us without cause or by Mr. Herz for good reason	3,932,384 ⁽³⁾	35,431	357,215
Termination upon a change of control	3,932,384		

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1)Dental and medical benefits were calculated using 2016 COBRA rates.

(2)Represents the value of unvested unit awards disclosed in the “2016 Outstanding Equity Awards at Fiscal Year-End” table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3)Represents two times (a) Mr. Herz’s base salary plus (b) average incentive compensation allocated to Titan. The following table provides an estimate of the value of the benefits to Mr. Schumacher, pursuant to his Titan Employment Agreement, if a termination event had occurred as of December 31, 2016:

Reason for termination	Lump sum severance payment	Benefits ⁽¹⁾	Accelerated vesting of unit awards and option awards ⁽²⁾
Death	\$400,000	\$17,791	\$133,957
Disability	400,000	17,791	133,957
Termination by us without cause or by Mr. Schumacher for good reason	1,610,000 ⁽³⁾	\$35,583	133,957
Termination upon a change of control	1,610,000		

*This table assumes the payment of the proposed 2016 bonus amounts, which have not been approved by the Conflicts Committee.

(1)Dental and medical benefits were calculated using 2016 COBRA rates.

(2)Represents the value of unvested unit awards disclosed in the “2016 Outstanding Equity Awards at Fiscal Year-End” table. Calculated by multiplying the number of accelerated units by the closing price of the applicable unit on December 31, 2016.

(3)Represents two times (a) Mr. Schumacher’s base salary plus (b) average incentive compensation allocated to Titan. Long-Term Incentive Plans

Titan Management Incentive Plan

The MIP permits the grant of options, phantom shares and restricted and unrestricted common shares, as well as dividend equivalent rights. A maximum of 25% of the shares available for issuance under the MIP shall be available for issuance pursuant to incentive stock options. Subject to adjustment in accordance with the MIP, a maximum of 655,555 common shares are reserved for issuance pursuant to awards under the MIP. Common shares subject to forfeited awards or withheld to satisfy exercise prices or tax withholding obligations will again be available for

delivery pursuant to other awards. Upon a change in control, all unvested awards held by directors shall immediately vest in full. The MIP has a term of 10 years and is administered by our board, which may delegate to a committee or our Chief Executive Officer.

Atlas Energy Group's 2015 Long-Term Incentive Plan

In February 2015, Atlas Energy Group adopted the Atlas Energy Group, LLC 2015 Long-Term Incentive Plan, which we refer to as the "2015 LTIP." The following is a brief description of the principal features of the 2015 LTIP.

Purpose

The 2015 LTIP is intended to promote Atlas Energy Group's interests by providing to Atlas Energy Group's officers, employees, and directors, employees of its affiliates, consultants, and joint venture partners who perform services for Atlas Energy Group incentive awards for superior performance that are based on its common units. The 2015 LTIP is intended to enhance Atlas Energy Group's ability to attract and retain the services of individuals who are essential for its growth and profitability, and to encourage them to devote their best efforts to Atlas Energy Group's business and advancing its interests.

Administration

Grants made under the 2015 LTIP are determined by Atlas Energy Group's board of directors or a committee appointed by the board of directors to administer the 2015 LTIP. Atlas Energy Group's board has appointed the Atlas Compensation Committee to administer the 2015 LTIP, which we refer to as the "committee."

Subject to the provisions of the 2015 LTIP, the committee is authorized to administer and interpret the 2015 LTIP, to make factual determinations, and to adopt or amend its rules, regulations, agreements, and instruments for implementing the 2015 LTIP. The committee also has the full power and authority to determine the recipients of grants under the 2015 LTIP as well as the terms and provisions of restrictions relating to grants.

Subject to any applicable law, the committee, in its sole discretion, may delegate any or all of its powers and duties under the 2015 LTIP, including the power to award grants under the 2015 LTIP, to Atlas Energy Group's Chief Executive Officer, subject to such limitations as the committee may impose, if any. However, the Chief Executive Officer may not make awards to, or take any action with respect to any grant previously awarded to, himself or a person who is subject to Rule 16b-3 under the Exchange Act.

Eligibility

Persons eligible to receive grants under the 2015 LTIP are (a) officers and employees of us, Atlas Energy Group's affiliates, consultants, or joint venture partners who perform services for Atlas Energy Group or an affiliate or in furtherance of Atlas Energy Group's business (we refer to each such officer and employee as an "eligible employee") and (b) Atlas Energy Group's non-employee directors.

Unit Reserve; Adjustments

Awards in respect of up to 5.25 million of Atlas Energy Group's common units may be issued under the 2015 LTIP. This amount is subject to adjustment as provided in the 2015 LTIP for events such as distributions (in common units or other securities or property, including cash), unit splits (including reverse splits), recapitalizations, mergers, consolidations, reorganizations, reclassifications, and other extraordinary events affecting our outstanding common units such that an adjustment is necessary in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the 2015 LTIP. Common units issued under the 2015 LTIP may consist of newly issued common units, common units acquired in the open market or from any of our affiliates, or any other person, or any combination of the foregoing. If any award granted under the 2015 LTIP is forfeited or otherwise terminates or is cancelled or paid without the delivery of common units, then the common units covered by the award will (to the extent of the forfeiture, termination, or cancellation, as the case may be) again be available for grants of awards under the 2015 LTIP. Common units surrendered in payment of the exercise price of an option, and withheld or surrendered for payment of taxes, will not be available for re-issuance under the 2015 LTIP.

Awards

Awards granted under the 2015 LTIP may consist of options to purchase common units, phantom units, and restricted units. All grants are subject to such terms and conditions as the committee deems appropriate, including vesting conditions.

Options. An option is the right to purchase a common unit in the future at a predetermined price (which we refer to as the "exercise price"). The exercise price of each option is determined by the committee and may be equal to or greater than the fair market value of a common unit on the date the option is granted. The committee will determine the vesting and exercise restrictions applicable to an award of options, if any, and the method or methods by which

payment of the exercise price may be made, which may include, without limitation, cash, check acceptable to Atlas Energy Group's board of directors, a tender of common units having a fair market value equal to the exercise price, a "cashless" broker-assisted exercise, a recourse note in a form acceptable to Atlas Energy Group's board of directors and that does not violate the Sarbanes-Oxley Act of 2002, a "net exercise" that permits Atlas Energy Group to withhold a number of common units that otherwise would be issued to the holder of the option pursuant to the exercise of the option having a fair market value equal to the exercise price, or any combination of the methods described above.

Phantom Units. Phantom units represent rights to receive common units, an amount of cash or other securities or property based on the value of a common unit, or a combination of common units and cash or other securities or property. Phantom units are subject to terms and conditions determined by the committee, which may include vesting restrictions. In addition, the committee may grant distribution equivalent rights in connection with a grant of phantom units. Distribution equivalent rights represent the right to receive an amount in cash, securities, or other property equal to, and at the same time as, the cash distributions or other distributions of securities or other property made by us with respect to common units during the period that the underlying phantom unit is outstanding. Distribution equivalents may (a) be paid currently or may be deferred and, if deferred, may accrue interest, (b) accrue as a cash obligation or may convert into additional phantom units for the holder of the underlying phantom units, (c) be payable based on the achievement of specific goals, and (d) be payable in cash or common units or in a combination of cash and common units, in each case as determined by the committee.

Restricted Units. Restricted units are actual common units issued to a participant that are subject to vesting restrictions and evidenced in such manner as the committee may deem appropriate, including book-entry registration or issuance of one or more unit certificates. Prior to or upon the grant of an award of restricted units, the committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals, or both. Unless otherwise determined by the committee, a holder of restricted units will have certain rights of holders of Atlas Energy Group’s common units in general, including the right to vote the restricted units. During the period during which the restricted units are subject to vesting restrictions, however, the holder will not be permitted to sell, assign, transfer, pledge, or otherwise encumber the restricted units. As determined by the committee, cash dividends on restricted units may be automatically deferred or reinvested in additional restricted units and held subject to the vesting of the underlying restricted units, and dividends payable in common units may be paid in the form of restricted units of the same class as the restricted units with respect to which the dividend is paid and may be subject to vesting of the underlying restricted units.

Change in Control

Individual Eligible employees	Triggering event	Acceleration
	Change of Control (as defined in the 2015 LTIP), and	Unvested awards immediately vest in full and in the case of options, become exercisable for the one-year period following the date of termination (but not later than the end of the original term of the option)
	Termination of employment without “cause” as defined in the 2015 LTIP or upon any other type of termination specified in the applicable award agreement(s), following a change of control	
Independent directors	Change of Control (as defined in the 2015 LTIP)	Unvested awards immediately vest in full

No Assignment

Except as otherwise determined by the committee, no award granted under the 2015 LTIP is assignable or transferable except by will or the laws of descent and distribution. When a participant dies, the personal representative or other person entitled to succeed to the rights of the participant may exercise the participant’s rights under his or her awards.

Withholding

All awards granted under the 2015 LTIP are subject to applicable federal (including FICA), state, and local tax withholding requirements. If we so permit, common units may be withheld to satisfy tax withholding obligations with respect to awards paid in common units, at the time such awards become subject to employment taxes and tax withholding, as applicable, up to an amount that does not exceed the minimum required withholding for federal (including FICA), state, and local tax liabilities. Atlas Energy Group may require forfeiture of any award for which the participant does not timely pay the applicable withholding taxes.

Amendment and Termination

Subject to the limitations described below, the committee may amend, alter, suspend, discontinue, or terminate the 2015 LTIP at any time without the consent of participants, except that the committee may not amend the 2015 LTIP without approval of the unitholders if such approval is required in order to comply with applicable stock exchange requirements. Atlas Energy Group may waive any conditions or rights under, amend any terms of, or alter any award previously granted under the 2015 LTIP; however, no change to any award previously granted under

the 2015 LTIP may materially reduce the benefit to a participant, unless the participant has consented or such change is explicitly allowed in the 2015 LTIP or the applicable award agreements. The committee may not reprice options, nor may the 2015 LTIP be amended to permit option repricing, unless the unitholders approve such repricing or amendment.

Plan Term

The 2015 LTIP will continue until the date terminated by Atlas Energy Group's board of directors or the date upon which common units are no longer available for the grant of awards, whichever occurs first.

Atlas Energy Group's Senior Executive Plan

In February 2015, Atlas Energy Group adopted the Atlas Energy Group, LLC Annual Incentive Plan for Senior Executives, which we refer to as the "Senior Executive Plan." The following is a summary of the Senior Executive Plan.

Purpose

The Senior Executive Plan provides a means for awarding annual incentive pay, a component of Atlas Energy Group's compensation program, to its senior executive employees and senior executive employees of its subsidiaries based on the achievement of performance goals over a designated performance period. The performance period is Atlas Energy Group's fiscal year or any other period of up to 12 months. The objectives of the Senior Executive Plan are:

- to enhance Atlas Energy Group's ability to attract, reward and retain senior executive employees;
- to strengthen employee commitment to Atlas Energy Group's success; and
- to align employee interests with those of Atlas Energy Group's unitholders by providing compensation that varies based on its success.

Administration

The Senior Executive Plan is administered and interpreted by the Atlas Compensation Committee. The committee has the authority to establish rules and regulations relating to the Senior Executive Plan, to interpret the Senior Executive Plan and those rules and regulations, to select participants, to determine each participant's maximum award and award amount, to approve all awards, to decide the facts in any case arising under the Senior Executive Plan, to make all other determinations, including factual determinations, and to take all other actions necessary or appropriate for the proper administration of the Senior Executive Plan, including the delegation of its authority or power, where appropriate.

Eligibility and Participation

Atlas Energy Group's, including our, senior executive employees are eligible to participate in the Senior Executive Plan. The Atlas Compensation Committee selects the senior executive employees who will participate in the Senior Executive Plan for each performance period.

Establishment of Performance Goals

As soon as practicable following the beginning of a performance period, the Atlas Compensation Committee determines the performance goals, and each participant's maximum award for the performance period. The performance goals may provide for differing amounts to be paid based on differing thresholds of performance.

Performance Objectives

The performance goals are based on performance objectives selected by the Atlas Compensation Committee for each performance period. In each period, the committee may consider factors including performance relative to an appropriate group designated by the committee, total market return and distributions paid to unitholders, and factors related to the operation of the business, including growth of reserves, growth in production, processing and intake of natural gas, health and safety performance, environmental compliance, and risk management. The aforementioned performance criteria may be considered either individually or in any combination, applied to us as a whole, to a subsidiary, to a business unit of us or any subsidiary, to an affiliate or any subsidiary, or to any individual, measured either annually or cumulatively over a period of time. To the extent applicable, the Atlas Compensation Committee, in determining whether and to what extent a performance goal has been achieved, will use the information set forth in Atlas Energy Group's and our audited financial statements and other objectively determinable information. The performance goals established by the committee may be (but need not be) different each performance period, and different performance goals may be applicable to different participants.

Calculation of Awards

A participant will earn an award for a performance period based on the level of achievement of the performance goals established by the Atlas Compensation Committee for that performance period. The committee may reduce or increase an award for any performance period based on its assessment of personal performance or other factors.

Payment of Awards

The Atlas Compensation Committee will certify and announce the awards that will be paid to each participant as soon as practicable following the final determination of Atlas Energy Group's and our financial results for the relevant performance period. Payment of the awards certified by the committee will be made as soon as practicable following the close of the performance period, but in any event within 2.5 months after the close of the performance period. Awards shall be paid in cash, in equity, or in a combination thereof. Any common or phantom units may be issued under any long-term incentive plan.

Limitations on Payment of Awards

Generally, a participant must be employed on the last day of a performance period to receive payment of an award under the Senior Executive Plan. If a participant's employment terminates before the end of the performance period, however, the Atlas Compensation Committee may determine that the participant will remain eligible to receive a prorated portion of any award that would have been earned for the performance period, in such circumstances as the committee deems appropriate. If a participant is on

an authorized leave of absence during the performance period, the participant may be eligible to receive a prorated portion of any award that would have been earned, as determined by the committee.

Change in Control

Unless the Atlas Compensation Committee determines otherwise, if a “change in control” (as defined in the Senior Executive Plan) occurs before the end of a performance period, each participant will receive an award for the performance period based on performance measured as of the date of the change in control.

Amendment and Termination of Plan

The Atlas Compensation Committee has the authority to amend, modify, or terminate the Senior Executive Plan at any time. In the case of a termination of the plan, each participant may receive all or a portion of the award that would otherwise have been earned for the then-current performance period had the Senior Executive Plan not been terminated, as determined by the committee.

2016 OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

Name	Option Awards			Option Expiration Date	Stock Awards	Market Value of Units that have not Vested
	Exerciseable	Unexerciseable	Option Exercise Price		Number of Units that have not Vested	
Daniel C. Herz	-	-	N/A	N/A	74,111 ⁽¹⁾	357,215
	-	-	N/A	N/A	250,000 ⁽²⁾	180,000
	-	-	-	-	200,000 ⁽³⁾	144,000
Jeffrey M. Slotterback	-	-	N/A	N/A	27,792 ⁽⁴⁾	133,957
	-	-	N/A	N/A	35,000 ⁽⁵⁾	25,200
	-	-	-	-	100,000 ⁽⁶⁾	72,000
Edward E. Cohen	-	-	N/A	N/A	74,111 ⁽¹⁾	357,215
	-	-	N/A	N/A	250,000 ⁽²⁾	180,000
	-	-	-	-	200,000 ⁽³⁾	144,000
Jonathan Z. Cohen	-	-	N/A	N/A	74,111 ⁽¹⁾	357,215
	-	-	N/A	N/A	250,000 ⁽²⁾	180,000
	-	-	-	-	200,000 ⁽³⁾	144,000
Mark D. Schumacher	-	-	N/A	N/A	27,792 ⁽⁴⁾	133,957
	-	-	N/A	N/A	175,000 ⁽⁷⁾	126,000
	-	-	-	-	100,000 ⁽⁸⁾	72,000

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- (1) Represents restricted Titan Energy, LLC shares which will vest as follows: 9/1/2017- 24,456; 9/1/2018 - 24,456; 9/1/2019 - 25,199.
- (2) Represents Atlas Energy phantom units, which vest as follows: 3/1/2018 - 165,000; 6/8/2018 - 85,000.
- (3) Represents Atlas Energy phantom units, which vest as follows: 3/1/2018 - 132,000; 6/8/2018 - 68,000.
- (4) Represents restricted Titan Energy, LLC shares which will vest as follows: 9/1/2017- 9,171; 9/1/2018 - 9,171; 9/1/2019 - 9,450.
- (5) Represents Atlas Energy phantom units, which vest as follows: 3/1/2018 - 23,100; 6/8/2018 - 11,900.
- (6) Represents Atlas Energy phantom units, which vest as follows: 3/1/2018 - 66,000; 6/8/2018 - 34,000.
- (7) Represents Atlas Energy phantom units, which vest as follows: 3/1/2018 - 115,500; 6/8/2018 - 59,500.

2016 OPTION EXERCISES AND UNITS VESTED TABLE

Name	Option Awards		Stock Awards	
	Number of Units Acquired on Exercise	Value Realized on Exercise	Number of Units Acquired on Vesting ⁽¹⁾	Value Realized on Vesting (\$)
Daniel C. Herz	-	-	37,000	178,340
Jeffrey M. Slotterback	-	-	13,875	66,878
Edward E. Cohen	-	-	37,000	178,340
Jonathan Z. Cohen	-	-	37,000	178,340
Mark D. Schumacher	-	-	20,125 ⁽²⁾	71,503

(1) Represents Titan common shares with a fair market value of \$4.82.

(2) Comprised of 13,875 Titan common shares with a fair market value of \$4.82 and 6,250 ARP common units with a fair market value of \$0.74.

2016 NONQUALIFIED DEFERRED COMPENSATION

Name	Executive contributions In the last FY (\$)	Registrant contributions in the last FY (\$)	Aggregate earnings in the last FY (\$)	Aggregate Withdrawals/Distributions (\$) ⁽¹⁾	Aggregate balance at last FYE (\$) ⁽²⁾
Edward E. Cohen	28,000	28,000 ⁽³⁾	2,359	1,011,110	1,069,469
Jonathan Z. Cohen	21,230	21,230 ⁽⁴⁾	1,747	707,777	751,984

(1) Contributions are invested in a mutual fund and cash balances are invested daily in a money market account.

(2) Represents the portion of the balance attributable to us.

(3) This amount is included within the Summary Compensation Table for 2016 reflecting our allocated portion of \$28,000 matching contribution in the all other compensation column.

(4) This amount is included within the Summary Compensation Table for 2016 reflecting our allocated portion of \$21,230 matching contribution in the all other compensation column.

Effective July 1, 2011, Atlas Energy established the Excess 401(k) Plan, an unfunded nonqualified deferred compensation plan for certain highly compensated employees. Atlas Energy Group assumed Atlas Energy's obligations under the plan as part of the Separation. The Excess 401(k) Plan provides Messrs. E. and J. Cohen, the plan's current participants, with the opportunity to defer, annually, the receipt of a portion of their compensation, and to permit them to designate investment indices for the purpose of crediting earnings and losses on any amounts deferred under the Excess 401(k) Plan. Messrs. E. and J. Cohen may defer up to 10% of their total annual cash compensation (which means base salary and non-performance-based bonus) and up to 100% of all performance-based bonuses, and Atlas Energy Group is obligated to match such deferrals on a dollar-for-dollar basis (i.e., 100% of the deferral) up to a total of 50% of their base salary for any calendar year. The account is invested in a mutual fund and cash balances are invested daily in a money market account. Atlas Energy established a "rabbi" trust to serve as the funding vehicle for the Excess 401(k) Plan and Atlas Energy Group will, not later than the last day of the first month of each calendar quarter, make contributions to the trust in the amount of the compensation deferred, along with the corresponding match, during the preceding calendar quarter. Notwithstanding the establishment of the rabbi trust, Atlas Energy Group's obligation to pay the amounts due under the Excess 401(k) Plan constitutes a general, unsecured obligation, payable out of its general assets, and Messrs. E. and J. Cohen do not have any rights to any specific asset of the company.

The Excess 401(k) Plan has the following additional provisions:

At the time the participant makes his deferral election with respect to any year, he must specify the date or dates (but not more than two) on which distributions will start, which date may be upon termination of employment or a date that is at least three years after the year in which the amount deferred would otherwise have been earned. A participant may subsequently defer a specified payment date for a minimum of an additional five years from the previously elected payment date. If the participant fails to make an election, all amounts will be distributable upon the termination of employment.

Distributions will be made earlier in the event of death, disability or a termination of employment due to a change of control.

If the participant elects to receive all or a portion of his distribution upon the termination of employment, it will be paid in a lump sum. Otherwise, the participant may elect to receive a lump sum payment or equal installments over

not more than 10 years.

• A participant may request a distribution of all or part of his account in the event of an unforeseen financial emergency. An unforeseen financial emergency is a severe financial hardship due to an unforeseeable emergency resulting from a sudden and unexpected illness or accident of the participant, or, a sudden and unexpected illness or accident of a dependent, or loss of the participant's property due to casualty, or other similar and extraordinary unforeseeable circumstances arising as a result of events beyond the control of the participant. An unforeseen financial emergency is not deemed to exist to the extent it is or may be relieved through reimbursement or compensation by insurance or otherwise; by borrowing from commercial sources on reasonable commercial terms to the extent that this borrowing would not itself cause a severe financial hardship; by cessation of deferrals under the plan; or by liquidation of the participant's other assets (including assets of the participant's spouse and minor children that are reasonably available to the participant) to the extent that this liquidation would not itself cause severe financial hardship.

The table above reflects salary and matching contribution costs allocated to us.

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DIRECTOR COMPENSATION

The following table sets forth compensation for 2016 for the directors of ARP's general partner's board of directors who served as ARP's directors prior to September 1, 2016.

Name	Fees earned or paid in cash(\$)	Stock awards(\$)	All other compensation(\$) ⁽¹⁾	Total(\$)
Mark C. Biderman	33,333	—	—	33,333
DeAnn Craig	26,667	—	216	26,883
Dennis A. Holtz	27,500	—	—	27,500
Walter C. Jones	26,875	—	—	26,875
Jeffrey F. Kupfer	25,625	—	—	25,625
Ellen F. Warren	28,333	—	—	28,333

(1) Represents payments on DERs for ARP phantom units.

The following table shows the compensation of the directors of ARP Holdings, who served as members of ARP's conflicts committee prior to September 1, 2016:

Name	Fees earned or paid in cash(\$)	Stock awards(\$)	All other compensation(\$) ⁽¹⁾	Total(\$)
Carlton M. Arrendell	32,424	8,200 ⁽²⁾	484	42,108
Tony C. Banks	32,424	8,200 ⁽²⁾	484	42,108
Jeffrey C. Key	32,424	8,200 ⁽²⁾	484	42,108

(1) Represents payments on DERs for ARP phantom units.

(2) Represents 10,000 phantom units granted under the ARP LTIP, having a grant date fair value of \$0.82, with the following vesting schedule: 1/2/2017—2,500 units; 1/2/2018—2,500 units; 1/2/2019—2,500 units; and 1/2/2020—2,500 units. On September 1, 2016, all ARP equity was cancelled.

The following table sets forth compensation of our directors September 1, 2016.

Name	Fees earned or paid in cash(\$)	Stock awards(\$)	All other compensation(\$)	Total(\$)
Eugene I. Davis	41,667	74,999	—	116,666
Michael C. Watchorn	41,667	74,999	—	116,666

Director Compensation

Our non-employee directors are entitled to receive annual compensation for services they provide for us consisting of a \$125,000 cash retainer (paid in quarterly installments) and equity compensation consisting of unrestricted Common Shares with an aggregate value equal to \$75,000 under our MIP.

Directors receive no meeting fees, but each director will be reimbursed for travel and miscellaneous expenses to attend meetings and activities of the Board or its committees.

Mr. Zawadzki has waived his receipt of compensation for serving as a non-employee director.

ITEM 12: SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the number and percentage of our common shares owned as of April 13, 2017, by (a) each person who, to our knowledge, is the beneficial owner of more than 5% of the outstanding shares, (b) each member of our board of directors, (c) each of our named executive officers serving during the 2016 fiscal year, and (d) all of our executive officers and members of the board of director as a group. This information is reported in accordance with the beneficial ownership rules of the Securities and Exchange Commission under which a person is deemed to be the beneficial owner of a security if that person has or shares voting power or investment power with respect to such security or has the right to acquire such ownership within 60 days. Shares issuable pursuant to options, warrants or phantom units are deemed to be outstanding for purposes of computing the percentage of the person

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or group holding such options, warrants or phantom units but are not deemed to be outstanding for purposes of computing the percentage of any other person. Unless otherwise indicated in footnotes to the table, each person listed has sole voting and dispositive power with respect to the securities owned by such person.

Beneficial owner	Common unit amount and nature of beneficial ownership	Percent of class	
Directors⁽¹⁾			
Edward E. Cohen	111,111	2.1	%
Jonathan Z. Cohen	111,111	2.1	%
Daniel C. Herz	111,111	2.1	%
Jeffrey M. Slotterback	41,667	*	
Eugene I. Davis	15,560	*	
Michael A. Zawadzki	--	--	
Michael C. Watchorn	15,560	*	
Non-director Named Executive Officers⁽¹⁾			
Mark D. Schumacher	41,667	*	
Other owners of more than 5% of outstanding units			
Fir Tree Inc.	1,071,123	(2)	19.8 %
Funds affiliated with GSO Capital Partners LP	947,139	(3)	17.5 %
Funds affiliated with Franklin Resources, Inc.	489,982	(4)	9.0 %
Funds affiliated with Guggenheim Capital, LLC	538,175	(5)	9.94 %

*Less than 1%

- (1) The business address for each director and executive officer is Park Place Corporate Center One, 1000 Commerce Drive, 4th Floor, Pittsburgh, PA 15275-1011.
- (2) Based on information in a Schedule 13D/A filed with the SEC by Fir Tree on September 28, 2016. Fir Tree is the investment manager to the Fir Tree Funds and has been granted investment discretion over portfolio investments, including the Common Shares held by the Fir Tree Funds. As a result, Fir Tree has the shared power to vote or direct the voting, and to dispose or direct the disposition of, the Common Shares beneficially owned by the Fir Tree Funds and may be deemed to beneficially own the Common Shares held by the Fir Tree Funds. The business address of Fir Tree is 55 West 46th Street, 29th Floor, New York, NY 10036.
- (3) Based on information in a Schedule 13D filed with the SEC on September 12, 2016 by: (i) the GSO Funds; (ii) GSO / Blackstone Debt Funds Management LLC, GSO Energy Market Opportunities Associates LLC, GSO Holdings I L.L.C. and GSO Capital Partners LP (collectively, with the GSO Funds, the "GSO Entities"); (iii) Bennett J. Goodman and J. Albert Smith III (collectively, the "GSO Executives"); (iv) GSO Advisor Holdings L.L.C., Blackstone Holdings I L.P., Blackstone Holdings II L.P., Blackstone Holdings I/II GP Inc., The Blackstone Group L.P. and Blackstone Group Management L.L.C. (collectively, the "Blackstone Entities"); (v) Stephen A. Schwarzman; (vi) FSEP, Foxfields Funding LLC, Cobbs Creek LLC, FSIC II, FSIC III (collectively, the "FS Funds"); (vii) FS Investment Advisor, LLC, FSIC II Advisor, LLC, FSIC III Advisor, LLC (collectively with the FS Funds, the "FS Entities"); and (viii) Michael C. Forman, Gerald F. Stahlecker, Zachary Klehr and Sean Coleman

(collectively, the “FS Persons”).

Blackstone / GSO Strategic Credit Fund directly holds 29,318 Common Shares and GSO Energy Market Opportunities Fund LP directly holds 116,545 Common Shares. GSO Energy Market Opportunities Associates LLC is the general partner of GSO Energy Market Opportunities Fund LP. GSO Holdings I L.L.C. is the managing member of GSO Energy Market Opportunities Associates LLC. Blackstone Holdings II L.P. is the managing member of GSO Holdings I L.L.C. with respect to securities beneficially owned by GSO Energy Market Opportunities Associates LLC. GSO / Blackstone Debt Funds Management LLC is the investment adviser of Blackstone / GSO Strategic Credit Fund. GSO Capital Partners LP is the managing member of GSO / Blackstone Debt Funds Management LLC. GSO Advisor Holdings L.L.C. is a special limited partner of GSO Capital Partners LP with investment and voting power over the securities beneficially owned by GSO Capital Partners LP. Blackstone Holdings I L.P. is the sole member of GSO Advisor Holdings L.L.C. Blackstone Holdings I/II GP Inc. is the general partner of each of Blackstone Holdings I L.P. and Blackstone Holdings II L.P. The Blackstone Group L.P. is the controlling shareholder of Blackstone Holdings I/II GP Inc. Blackstone Group Management L.L.C. is the general partner of The Blackstone Group L.P. Blackstone Group Management L.L.C. is wholly-owned by Blackstone’s senior managing directors and controlled by its founder, Stephen A. Schwarzman. In addition, each of Bennett J. Goodman and J. Albert Smith III may be deemed to have shared voting power and/or investment power with respect to the Common Shares held by the GSO Funds.

FSIC II directly holds 134,000 Common Shares, FSIC III directly holds 72,739 Common Shares, FSEP directly holds 468,497 Common Shares, Foxfields Funding LLC directly holds 87,000 Common Shares and Cobbs Creek LLC directly holds 66,040 Common Shares. FSIC II Advisor, LLC, FSIC III Advisor, LLC and FS Investment Advisor, LLC are the investment advisers of FSIC II, FSIC III and FSEP, respectively, and in that respect hold discretionary investment authority for them. FSIC II is the sole member of Cobbs Creek LLC. FSEP is the sole member of Foxfields Funding LLC. In addition, each of Michael C. Forman, Gerald F. Stahlecker, Zachary Klehr and Sean Coleman may be deemed to have shared voting, investment and/or dispositive power with respect to the Common Shares held by the FS Funds.

Michael Zawadzki, an employee of GSO Capital Partners LP and/or one of its affiliates, is a member of the Board. Mr. Zawadzki disclaims beneficial ownership of any Common Shares that may be deemed beneficially owned by GSO Capital Partners LP and/or its affiliates.

The principal business address of each of the GSO Entities and GSO Executives is c/o GSO Capital Partners LP, 345 Park Avenue, New York, New York 10154. The principal business address of each of the Blackstone Entities and Mr. Schwarzman is c/o The Blackstone Group L.P., 345 Park Avenue, New York, New York 10154. The principal business address of each of the FS Entities and the FS Persons is 201 Rouse Boulevard, Philadelphia, Pennsylvania 19112.

- (4) Based on information in a Schedule 13G filed by with the SEC on February 7, 2017 by: (i) Franklin Resources, Inc. (“FRI”), (ii) Charles B. Johnson, (iii) Rupert H. Johnson, Jr. and (iv) Franklin Advisers, Inc. The securities are beneficially owned by one or more open or closed end investment companies or other managed accounts that are investment management clients of investment managers that are direct and indirect subsidiaries of FRI. Charles B. Johnson and Rupert H. Johnson, Jr. (the “Principal Shareholders”) each own in excess of 10% of the outstanding common stock of FRI and are the principal stockholders of FRI. FRI and the Principal Shareholders may be deemed to be the beneficial owners of securities held by persons and entities for whom or for which FRI subsidiaries provide investment management services. The business address of FRI, the Principal Stockholders and Franklin Advisers, Inc. is One Franklin Parkway, San Mateo, CA 94403-1906.
- (5) Based on information in a Schedule 13G filed by with the SEC on February 14, 2017 by: (i) Guggenheim Capital, LLC, (ii) Guggenheim Partners, LLC, (iii) GI Holdco II LLC, (iv) GI Holdco LLC, (v) Guggenheim Partners Investment Management Holdings, LLC, and (vi) Guggenheim Partners Investment Management, LLC (“GPIM”). Guggenheim Capital, LLC may be deemed the beneficial owner of 538,175 Common Shares, which amount includes 510,206 Common Shares beneficially owned directly by GPIM, and indirectly by Guggenheim Partners Investment Management Holdings, LLC, GI Holdco LLC, GI Holdco II LLC and Guggenheim Partners, LLC and 27,969 Common Shares beneficially owned directly by a subsidiary of Guggenheim Capital, LLC. The business address of Guggenheim Capital, LLC and Guggenheim Partners, LLC is 227 West Monroe Street, Chicago, IL 60606; the business address of GI Holdco II LLC and GI Holdco LLC is 330 Madison Avenue, New York, NY 10017; the business address of Guggenheim Partners Investment Management Holdings, LLC is 330 Madison Avenue, New York, NY 10017; and the business address of GPIM is 100 Wilshire Boulevard, 5th Floor, Santa Monica, CA 90401.

Equity Compensation Plan Information

The following table contains information about our Plan as of December 31, 2016:

Plan category	Number of securities to be issued upon exercise of equity instruments (a)	Weighted-average price of outstanding equity instruments (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders—phantom units	111,000	\$ N/A	--
Equity compensation plans not approved by security holders ⁽¹⁾ —unit options	--	\$ --	

Total	111,000	\$	96,768
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(1)The Titan Energy, LLC Management Incentive Plan was approved by the United States Bankruptcy Court for the Southern District of New York in connection with the order confirming our Predecessor’s pre-packaged plan of reorganization, which became effective on September 1, 2016.

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

Our Relationship with ATLS

Following the consummation of the transactions pursuant to the Plan, on September 1, 2016, we entered into a Delegation of Management Agreement (the “Delegation Agreement”) with ATLS. Pursuant to the Delegation Agreement, we have delegated to Titan Management all of our rights and powers to manage and control the business and affairs of Titan Operating. However, our Board retains management and control over certain non-delegated duties.

Other than our named executive officers, we do not directly employ any persons to manage or operate our business. These functions are provided by ATLS’ employees and affiliates, including Titan Management. In connection therewith, we and certain of our subsidiaries entered into an Omnibus Agreement (the “Omnibus Agreement”) dated September 1, 2016 with us. Pursuant to the Omnibus Agreement, ATLS will provide us with certain financial, legal, accounting, tax advisory, financial advisory and engineering services (including cash management services) and we and Titan Operating will reimburse ATLS for direct and allocable indirect expenses incurred in connection with the provision of the services, subject to certain approval rights in favor of our Conflicts Committee.

Upon termination of the Omnibus Agreement (other than due to a breach by Titan Management), we will pay to Titan Management an amount sufficient to reimburse Titan Management for all severance and related costs it is expected to incur due to staff reduction (excluding any executive with an employment agreement with us, which executive shall receive payment under his or her employment agreement) in connection with such termination based upon the severance plans and arrangements of Titan Management and its affiliates in place at such time which shall be consistent with existing staff severance policies, subject to certain exceptions. The reimbursement obligation is subject to a cap of \$14.9 million.

For the year ended December 31, 2016, we (and our Predecessor) reimbursed ATLS \$47.0 million for expenses, compensation and benefits.

Following the consummation of the transactions pursuant to the Plan, Titan Management, as the holder of our Series A Preferred Share, has the ability to appoint four Class A directors to our Board. In addition, the holder of the Series A Preferred Share (currently Titan Management) is entitled to 2% of the aggregate of distributions paid to shareholders, subject to dilution if catch-up contributions are not made with respect to future equity issuances (other than any share split which is not a Series A Distribution or pursuant to the Titan Energy, LLC Management Incentive Plan, in each case as to which there shall be no adjustment to the percentage interest of the Series A Preferred Share). The Series A Preferred Share has voting rights identical to our common shares representing limited liability company interests (the "Common Shares") and votes as a single class with our Common Shares with voting power equal to its then-applicable percentage interest; provided, that the Series A Preferred Share has no right to vote with respect to the election or removal of Class B directors or the exercise of the Preferred Share Call Right.

Common Share Issuance

On September 1, 2016, we issued 5,000,000 new Common Shares in accordance with the Plan. The Second Lien Lenders received 500,000 Common Shares (representing 10% of the initially outstanding Common Shares). Holders of our Predecessor's senior notes, in exchange for 100% of the \$668 million aggregate principal amount of notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 cases, received 4,500,000 Common Shares (representing 90% of the initially outstanding Common Shares). On September 1, 2016, we also issued the Series A Preferred Share to Titan Management.

Registration Rights Agreement

In connection with the issuance of the Common Shares as of September 1, 2016 to the Second Lien Lenders and the holders of our Predecessor's senior notes, we entered into the Registration Rights Agreement, dated as of September 1, 2016, with the holders who received at least 5% of our outstanding Common Shares (the "Holders"), relating to the registered resale of the Common Shares. Pursuant to the Registration Rights Agreement, we are required to use our commercially reasonable efforts to file a shelf registration statement within 90 days of September 1, 2016 and use commercially reasonable efforts to cause such registration statement to become effective within 180 days of September 1, 2016. In certain circumstances, the Holders will have piggyback registration rights on certain registered offerings and will have rights to request underwritten offerings. The Holders will cease to have rights under the Registration Rights Agreement on the tenth anniversary of September 1, 2016.

Pursuant to the Registration Rights Agreement, we filed a Registration Statement on Form S-1 (File No. 333-214850) on November 30, 2016, which the SEC declared effective on December 14, 2016.

Our Relationship with AGP

Anthem is currently acting as the dealer manager for AGP's issuance and sale in a continuous offering of up to a maximum agreement amount of 100,000,000 common units representing limited partner interests in AGP as further described in AGP's registration statement on Form S-1 (File No. 333-207537). AGP will pay Anthem (1) compensation equal to 3.00% of the gross proceeds of the offering (Anthem may reallocate up to 1.50% of gross offering proceeds it receives as dealer manager fees to participating broker-dealers, but expects to reallocate 1.25% of gross offering proceeds to participating broker-dealers); (2) 7.00% and 3.00% of aggregate gross proceeds from the sale of Class A common units and Class T common units, respectively, as sales commissions; (3) with respect to Class T common units, a distribution and unitholder servicing fee in the aggregate amount of 4.00% of the gross proceeds from the sale of Class T common units, which distribution and unitholder servicing fee will be withheld from cash distributions otherwise payable to the purchasers of Class T common units at a rate of \$0.025 per quarter per unit. On November 2, 2016, AGP decided to temporarily suspend its current primary offering efforts.

Drilling Partnerships

On October 24, 2016, the board of directors of our subsidiary, Atlas Resources, LLC, approved our acquisition of properties in exchange for assuming all liabilities in connection with the consolidation of certain of our Drilling Partnerships. These acquisitions have an effective date of October 1, 2016. We recorded \$31.0 million and \$14.7 million of gas and oil properties and asset retirement

obligations, respectively, resulting in non-cash gain of \$22.4 million, net of other consolidation and transfer adjustments, in the successor period from September 1, 2016 through December 31, 2016 on our consolidated statement of operations.

Relationship with Resource America

Edward E. Cohen, our Chief Executive Officer, serves as Chairman of Resource America, Inc. (“Resource America”) and is a greater than 10% shareholder, and Jonathan Z. Cohen, our Executive Chairman, serves as Chief Executive Officer and President of Resource America and is a greater than 10% shareholder. Resource America subleases office space from us and paid us \$0.1 million for the fiscal year ended December 31, 2016. We reimbursed Resource America for other shared services and paid Resource America \$0.1 million for the fiscal year ended December 31, 2016.

Indemnification of Directors and Officers and Members of Our Board of Directors

Under our LLC Agreement, in most circumstances, we will indemnify the following persons, by reason of their status as such, to the fullest extent permitted by law, from and against all losses, claims or damages arising out of or incurred in connection with our business:

- any person who is or was a manager, managing member, officer, director, employee, agent, tax matters partner, fiduciary or trustee of us or our subsidiaries, or any of our affiliates or their subsidiaries;

• us or our subsidiaries, or any of our affiliates or their subsidiaries;

• any person who is or was serving at our request as a manager, managing member, officer, director, employee, agent, tax matters partner, fiduciary or trustee of another person;

• Titan Management, its affiliates and any manager, managing member, officer, director, employee or agent of Titan Management or its affiliates with respect to the Delegation Agreement;

• any person whom the Board designates as an indemnitee for purposes of our LLC Agreement; and

• GSO and its affiliates, including any manager, managing member, officer, director, employee or agent of GSO, the GSO funds and any manager, managing member, officer, director, employee or agent of the GSO funds, solely, in each case, in its capacity as a person who has or had the right to designate or appoint a Class B director.

The indemnification obligation arises only if the indemnified person did not act in bad faith or engage in fraud, willful misconduct or, in the case of a criminal matter, knowledge of the indemnified person’s unlawful conduct.

We are permitted to purchase, and have so purchased, insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our LLC Agreement.

Review, Approval or Ratification of Transactions with Related Parties

If a conflict or potential conflict of interest arises as a result of the relationships between our directors, officers, affiliates (including ATLS and Titan Management) and owners (including affiliates of the Class B directors), on the one hand, and us and our shareholders, on the other hand, or as a result of the duties of Titan Management to act for the benefit of its owners, which may conflict with our interests and the interests of our public shareholders, the Board will resolve any such conflict or potential conflict in accordance with the provisions of our LLC Agreement.

The principal functions of the Conflicts Committee are to review and approve transactions or arrangements with our management, Titan Management or ATLS, or other affiliates. The Conflicts Committee's responsibilities include: approving the allocation methodologies for general and administrative costs allocated to us by ATLS, as well as any changes to such allocations; approving new or additional compensation arrangements for named executive officers; approving the investment by Titan Management in any tax advantaged partnerships; approving any modifications, waivers or amendments of the Omnibus Agreement and the Delegation Agreement; and providing certain waivers under the tax matters agreement.

In addition, our LLC Agreement provides that certain matters require the approval of a majority of the Class B directors prior to the Fallaway Date, including, but not limited to: (i) certain refinancings of indebtedness; (ii) issuances of equity securities; (iii) exercise of the Preferred Share Call Right; (iv) non-ordinary course asset sales with expected proceeds of at least \$50 million; (v) our liquidation or dissolution or any of our material subsidiaries; (vi) acquisitions in excess of \$50 million; (vii) merger transactions

involving us or Titan Operating; (viii) certain related party transactions; (ix) incurrence of indebtedness in excess of \$100 million or entering into certain types of financing transactions; and (x) the identification of disqualified lenders. In addition, the GSO-designated Class B director retains a veto right over certain refinancings of indebtedness and identification of disqualified lenders.

Director Independence

We have no securities listed for trading on a national securities exchange, but our Common Shares are quoted on the OTCQX Market. As a result, we are not required to have a majority of independent directors, though the OTCQX Market does require that we have at least two. We have adopted the definitions of independence used by the OTC. Our Board has determined that each of Messrs. Davis, Zawadzki and Watchorn is independent under each of those definitions.

ITEM 14: PRINCIPAL ACCOUNTANT FEES AND SERVICES

For the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the year ended December 31, 2015, the accounting fees and services charged by Grant Thornton, LLP, our and our Predecessor's independent auditors, were as follows (in thousands):

	Successor Period from September 1, 2016 to December 31, 2016	Predecessor Period from January 1, 2016 to August 31, 2016	Year Ended December 31, 2015
Audit fees ⁽¹⁾	\$ 660	\$378	\$ 1,199
Audit-related fees ⁽²⁾	—	62	67
Tax fees ⁽³⁾	—	115	98
Total accounting fees and services	\$ 660	\$555	\$ 1,364

(1) Represents the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP principally for the audits of our and our Predecessor's annual financial statements and the reviews of our and our Predecessor's quarterly financial statements included in Form 10-Qs and also for services related to registration statements, Form 8-Ks, comfort letters and our Predecessor's Restructuring.

(2) Represents the aggregate fees recognized during the Successor period from September 1, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through August 31, 2016 and the year ended December 31, 2015 for professional services rendered by Grant Thornton LLP substantially related to certain necessary audit related services in connection with the registration and/or private placement of our Drilling Partnerships.

(3) Represent the fees for tax services rendered related to tax compliance.

Audit Committee Pre-Approval Policies and Procedures

The audit committee of our general partner, on at least an annual basis, will review audit and non-audit services performed by Grant Thornton LLP as well as the fees charged by Grant Thornton LLP for such services. Our policy is that all audit and non-audit services must be pre-approved by the audit committee. All of such services and fees were

pre-approved during 2016 and 2015.

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PART IV

ITEM 15: EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

(1) Financial Statements

The financial statements required by this Item 15(a)(1) are set forth in “Item 8: Financial Statements and Supplementary Data”.

(2) Financial Statement Schedules

None

(3) Exhibits:

Exhibit Number Description of Exhibit

- 2.1 Joint Prepackaged Chapter 11 Plan of Reorganization of Atlas Resource Partners, L.P., et al., pursuant to Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.1 to our Predecessor’s Current Report on Form 8-K filed August 29, 2016)
- 2.2 Confirmation Order, dated August 26, 2016 (incorporated by reference to Exhibit 2.2 to our Predecessor’s Current Report on Form 8-K filed August 29, 2016)
- 2.3(a)** Purchase and Sale Agreement, dated September 24, 2014, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. (incorporated by reference to Exhibit 2.1 to our Predecessor’s Current Report on Form 8-K filed September 30, 2014) ⁽³⁾
- 2.3(b) First Amendment to Purchase and Sale Agreement dated October 27, 2014, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. (incorporated by reference to Exhibit 2.1 to our Predecessor’s Current Report on Form 8-K filed November 6, 2014)
- 2.3(c) Second Amendment to Purchase and Sale Agreement dated March 31, 2015, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. (incorporated by reference to Exhibit 2.1 to our Predecessor’s Current Report on Form 8-K filed April 6, 2015) ⁽⁵⁾
- 2.4(a)** Shared Acquisition and Operating Agreement, dated September 24, 2014, by and among ARP Eagle Ford, LLC and Atlas Growth Eagle Ford, LLC (incorporated by reference to Exhibit 2.2 to our Predecessor’s Current Report on Form 8-K filed September 30, 2014)
- 2.4(b)** Amended and Restated Shared Acquisition and Operating Agreement, effective as of September 24, 2014, by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC. (incorporated by reference to Exhibit 2.4(b) to our Predecessor’s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015)
- 2.4(c)** Addendum #2 to the Amended and Restated Shared Acquisition and Operating Agreement by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC, effective as of July 1, 2015. (incorporated by reference to Exhibit 2.4(c) to our Predecessor’s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015)
- 2.4(d)** Addendum #3 to the Amended and Restated Shared Acquisition and Operating Agreement by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC, effective as of September 30, 2015. (incorporated by reference to Exhibit 2.4(d) to our Predecessor’s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2015)

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Exhibit Number	Description of Exhibit
2.5	Purchase and Sale Agreement, dated May 18, 2015, by and between New Atlas Holdings, LLC and ARP Production Company, LLC (incorporated by reference to Exhibit 2.1 to our Predecessor's Current Report on Form 8-K filed May 22, 2015)
3.1(a)	Certification of Conversion of Titan Energy, LLC (incorporated by reference to Exhibit 3.1(a) to our Predecessor's Current Report on Form 8-K filed May 22, 2015)
3.1(b)	Certificate of Formation of Titan Energy, LLC
3.2	Amended and Restated Limited Liability Company Agreement of Titan Energy, LLC, dated as of September 1, 2016 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed September 7, 2016)
4.1	
10.1	Forbearance and Waiver Agreement, dated as of July 11, 2016, by and among Atlas Resources, LLC, Wells Fargo Bank, National Association, as administrative agent, and the other lenders thereto (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q filed November 21, 2016)
10.2	
10.3	Restructuring Support Agreement dated July 25, 2016 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed July 25, 2016)
10.4	Third Amended and Restated Credit Agreement, dated as of September 1, 2016, among Titan Energy Operating, LLC, Titan Energy, LLC, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed September 7, 2016)
10.5	Amended and Restated Second Lien Credit Agreement, dated as of September 1, 2016, among Titan Energy Operating, LLC, Titan Energy, LLC, the lenders from time to time party thereto and Wilmington Trust, National Association, as administrative agent and collateral agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed September 7, 2016)
10.6	Registration Rights Agreement, dated as of September 1, 2016, by and among Titan Energy, LLC and the holders party thereto (incorporated by reference to Exhibit 10.3o our Current Report on Form 8-K filed September 7, 2016)
10.7	Delegation of Management Agreement, dated as of September 1, 2016, by and between Titan Energy, LLC and Titan Energy Management, LLC (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed September 7, 2016)
10.8	Omnibus Agreement, dated as of September 1, 2016, by and among Titan Energy, LLC, Titan Energy Operating, LLC, Titan Energy Management, LLC and Atlas Energy Resource Services, Inc. (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K filed September 7, 2016)
10.9	Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Edward E. Cohen(incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K filed September 7, 2016)
10.10	Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Jonathan Z. Cohen (incorporated by reference to Exhibit 10.7 to our Current Report on Form 8-K filed September 7, 2016)
10.11	Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Daniel C. Herz (incorporated by reference to Exhibit 10.8 to our Current Report on Form 8-K filed September 7, 2016)

Exhibit Number	Description of Exhibit
10.12	Employment Agreement among Titan Energy, LLC and Titan Energy Operating, LLC and Mark Schumacher (incorporated by reference to Exhibit 10.9 to our Current Report on Form 8-K filed September 7, 2016)
10.13	Titan Energy, LLC Management Incentive Plan (incorporated by reference to Exhibit 10.10 to our Current Report on Form 8-K filed September 7, 2016)
10.14	Amended and Restated Titan Energy, LLC Management Incentive Plan (incorporated by reference to Exhibit 10.1 to our Current Report on 8-K filed November 1, 2016)
10.15	Form of Stock Grant Agreement – Initial Award (incorporated by reference to Exhibit 10.11 to our Current Report on Form 8-K filed September 7, 2016)
10.16	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Edward E. Cohen, dated September 4, 2015 (incorporated by reference to Exhibit 10.1 to our Predecessor’s Current Report on Form 8-K filed September 4, 2015)
10.17	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Jonathan Z. Cohen, dated September 4, 2015 (incorporated by reference to Exhibit 10.1 to our Predecessor’s Current Report on Form 8-K filed September 4, 2015)
10.18	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Daniel C. Herz, dated September 4, 2015 (incorporated by reference to Exhibit 10.1 to our Predecessor’s Current Report on Form 8-K filed September 4, 2015)
10.19	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Mark Schumacher, dated September 4, 2015 (incorporated by reference to Exhibit 10.1 to our Predecessor’s Current Report on Form 8-K filed September 4, 2015)
21.1	Subsidiaries of Titan Energy, LLC (incorporated by reference to Exhibit 21.1 to our Registration Statement on Form S-1 filed November 30, 2016)
23.1*	Consent of Grant Thornton LLP
23.2*	Consent of Wright and Company, Inc.
23.3*	Consent of Cawley, Gillespie, and Associates, Inc.
24.1	Powers of Attorney of the Directors and Officers of the Registrant (included in signature pages)
31.1*	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2*	Rule 13(a)-14(a)/15(d)-14(a) Certification
32.1*	Section 1350 Certification
32.2*	Section 1350 Certification
99.1*	Summary Reserve Report of Wright & Company, Inc.
99.2*	Rangely Summary Reserve Report of Cawley, Gillespie, and Associates, Inc.
101.INS***	XBRL Instance Document
101.SCH***	XBRL Schema Document
101.CAL***	XBRL Calculation Linkbase Document
101.LAB***	XBRL Label Linkbase Document
101.PRE***	XBRL Presentation Linkbase Document

Exhibit Number	Description of Exhibit
101.DEF***	XBRL Definition Linkbase Document

*Provided herewith.

**The schedules have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.

*** Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is “unaudited” or “unreviewed.”

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TITAN ENERGY, LLC

Date: April 17, 2017 By: /s/ Daniel C. Herz
Daniel C. Herz
Chief Executive Officer and Director

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant in the capacities indicated as of April 17, 2017.

/s/ Daniel C. Herz Chief Executive Officer and Director (Principal Executive Officer)
Daniel C. Herz

/s/ Jeffrey M. Slotterback Chief Financial Officer and Director (Principal Financial Officer)
Jeffrey M. Slotterback

/s/ Matthew J. Finkbeiner Chief Accounting Officer
Matthew J. Finkbeiner

/s/ Edward E. Cohen Executive Chairman of the Board
Edward E. Cohen

/s/ Jonathan Z. Cohen Executive Vice Chairman of the Board
Jonathan Z. Cohen

/s/ Eugene Davis Director
Eugene Davis

/s/ Michael Zawadzki Director
Michael Zawadzki

/s/ Michael Watchorn Director
Michael Watchorn

