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

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

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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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.

MMcfed. 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.

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,” “m “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:

	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
Production per day:				
Natural gas (Mcfd)	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 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
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

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 contributions	Our contributions	Total 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 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
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;

- 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;

- 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;

- 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 CO_2 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 CO_2. The ability to produce oil and NGLs from these assets would be hindered if the supply of CO_2 was limited due to, among other things, problems with the Rangely Field’s current CO_2 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 CO_2 injections and, in particular, on the operator’s ability to increase its combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 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.

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.

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.

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 September 1 through December 31, 2016	Period From January 1 through August 31, 2016	2015	2014	2013	2012
		(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)

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 Years Ended December 31, 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."

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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 CO_2 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	Predecessor		
	Period From September 1 through December 31, 2016	Period From January 1 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Gross wells drilled[3]:				
Appalachia	—	—	—	4
North Texas	—	—	3	97
Eagle Ford	—	2	21	2
Mid-Continent	—	—	4	26
Total	—	2	28	129
Net wells drilled[1][3]:				
Appalachia	—	—	—	1
North Texas	—	—	2	51
Eagle Ford	—	2	12	1
Mississippi Lime	—	—	3	14
Total	—	2	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.

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 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 volumes per day:(1)				
Appalachia:(2)				
Natural gas (Mcfd)	36,654	30,925	34,764	40,975
Oil (Bpd)	275	292	353	406
NGLs (Bpd)	312	307	296	371
Total (Mcfed)	40,175	34,522	38,658	45,635
Coal-bed Methane:(2)				
Natural gas (Mcfd)	112,366	117,491	129,453	132,296
Oil (Bpd)	—	—	—	—
NGLs (Bpd)	—	—	—	—
Total (Mcfed)	112,366	117,491	129,453	132,296
North Texas:(2)				
Natural gas (Mcfd)	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 (Mcfed)	38,205	43,002	60,555	79,946
Rangely(3):				
Natural gas (Mcfd)	—	—	—	—
Oil (Bpd)	2,210	2,287	2,375	1,252
NGLs (Bpd)	241	244	254	132
Total (Mcfed)	14,706	15,187	15,778	8,305
Eagle Ford(4):				
Natural gas (Mcfd)	531	437	315	175
Oil (Bpd)	1,982	1,212	1,443	286
NGLs (Bpd)	111	91	66	40
Total (Mcfed)	13,086	8,257	9,370	2,133
Mid-Continent:(2)				
Natural gas (Mcfd)	3,106	4,413	6,861	7,248
Oil (Bpd)	97	179	404	427
NGLs (Bpd)	247	356	546	561
Total (Mcfed)	5,170	7,624	12,560	13,172
Total production volumes per day:				
Natural gas (Mcfd)	183,151	186,962	216,613	238,054
Oil (Bpd)	4,739	4,224	5,139	3,436

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.

(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	Predecessor		
	Period From September 1 through December 31, 2016	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

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

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

	Successor	Predecessor		
	Period From September 1 through December 31, 2016	Period From January 1 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
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.

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

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	Predecessor		
	Period From September 1 through December 31, 2016	Period From January 1 through August 31, 2016	Year Ended December 31, 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

	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 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

(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
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 or 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 September 1 through December 31, 2016	Period From January 1 through August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 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.

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)

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

	September 1 through December31, 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

- $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,

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	Predecessor		
	Period From September 1 through December 31, 2016	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):

		Payments Due By Period			
	Total	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			
	Total	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.

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- 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:

Type	Production Period Ending December 31,	Volumes(1)	Average Fixed 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.

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)

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.

TITAN ENERGY, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share and unit data)

	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:				
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)

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	Predecessor		
	Period from September 1, 2016 through December 31,	Period from January 1, 2016 through August 31,	Year Ended December 31,	Year Ended December 31,
	2016	2016	2015	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)

erest	Preferred Limited Partners' Interest Class B		Class C		Class D		Class E		Common Limited Partners' Interests		Class C Common Limited Partner Warra	
Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Amo
4,482	3,836,554	96,539	3,749,986	86,938	—	—	—	—	59,448,308	917,417	562,497	1,1
(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)	—	—

—	—	—	—	—	—	—	—	—	—	—	—	—
$(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	—	—

	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)
	—	———		—	—	—	—	—	—	—	—	—
,953)	34,902	———		—	(4,090,328)	(97,853)	(256,083)	(5,845)	(106,180,706)	357,124	—	—
	$—	$——		$—	—	$—	—	$—	—	$—	—	$—

Successor	Series A Preferred Member's Interest Shares	Amount	Common Shareholders' Interest Shares	Amount	Total Members' 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.

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TITAN ENERGY, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

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

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, I 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:

Predecessor Consolidated Statement of Operations	Previously Filed	Adjustment	Restated
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)

Net loss attributable to common limited partners per unit – diluted	$(8.63)	$ (0.02)	$(8.65)
Year Ended December 31, 2014:			
Common limited partners' interest	$(625,133)	$ (3,793)	$(628,926)
General partner's interest	$(1,222)	$ 3,793	$2,571
Net loss attributable to common limited partners per unit – basic	$(8.37)	$ (0.05)	$(8.42)
Net loss attributable to common limited partners per unit – diluted	$(8.37)	$ (0.05)	$(8.42)
Predecessor Consolidated Balance Sheet			
December 31, 2015:			
Common limited partners’ interest	$(260,276)	$ (2,486)	$(262,762)
General partners’ interest	$(33,642)	$ 2,486	$(31,156)

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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 adjusts 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 ("Mcfe") 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:

Predecessor Consolidated Balance Sheet	Previously 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.

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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 August 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 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 January 1,	Year Ended December 31,	Year Ended December 31,

	2016 through August 31, 2016	2015	2014
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.

(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 August 31, 2016	Reorganization Adjustments	Fresh Start Adjustments	Successor September 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)	—	—

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

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.

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

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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.

	Predecessor	Fresh Start 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)

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)

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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 Predeccesor'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

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, 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 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)