Atlas Resource Partners, L.P.
Form 10-K
March 07, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR

o 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

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction or incorporation or organization)	45-3591625 (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:

Title of each class	Name of each exchange on which registered
Common Units representing Limited Partnership Interests	New York Stock Exchange
8.625% Class D Cumulative Redeemable Perpetual Preferred Units	New York Stock Exchange
10.75% Class E Cumulative Redeemable Perpetual Preferred Units	New York Stock Exchange

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

None

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

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 o No x

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 x No o

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 x No o

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. x

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

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Smaller reporting company ¨

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

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 common units on the last business day of the registrant's most recently completed second quarter, June 30, 2015, was approximately $457.9 million.

The number of outstanding common limited partner units of the registrant on February 29, 2016 was 102,421,097.

DOCUMENTS INCORPORATED BY REFERENCE: None

ATLAS RESOURCE PARTNERS, L.P.

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GLOSSARY OF TERMS

Unless the context otherwise requires, references below to “Atlas Resource Partners, L.P.,” “Atlas Resource Partners,” “the Partnership,” “we,” “us,” “our” and “our company”, when used in a historical context, refer to the subsidiaries and operations that Atlas Energy, L.P. contributed to Atlas Resource Partners in connection with the separation and distribution completed in March 2012, and, when used in the present tense or prospectively, refer to Atlas Resource Partners, L.P. and its combined subsidiaries. References below to “Atlas Energy” or “Atlas Energy, L.P.” refers to Atlas Energy, L.P. and its consolidated subsidiaries prior to the February 2015 merger of Atlas Energy discussed herein, unless the context otherwise requires.

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

Bcf. One billion cubic feet of natural gas.

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.

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.

Dth. One dekatherm, equivalent to one million British thermal units.

Dth/d. Dekatherms per day.

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 or a stratigraphic test well.

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. The total acres or wells, as the case may be, in which a working interest is owned.

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.

MMcf. One million cubic feet of natural gas.

MMcfe. MMcf 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. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

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.

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 drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

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. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves.

Unproved Reserves. Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible 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:

- the demand for natural gas, oil, NGLs and condensate;
- the price volatility of natural gas, oil, NGLs and condensate;
- changes in the differential between benchmark prices for oil and natural gas and wellhead prices that we receive;
- changes in the market price of our units;
- future financial and operating results;
- our ability to meet our liquidity needs, including as a result of borrowing base redeterminations;
- restrictive covenants in the debt documents governing our indebtedness that may adversely affect operational flexibility;
- 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;
- effects of debt payment obligations on our distributable cash;
- resource potential;
- our ability to meet or exceed the continued listing standards of the New York Stock Exchange;
- effects of partial depletion or drainage by earlier offset drilling on our acreage;
- success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves;
- the accuracy of estimated natural gas and oil reserves;
- the financial and accounting impact of hedging transactions;
- the ability to fulfill our substantial capital investment needs;
- expectations with regard to acquisition activity, or difficulties encountered in connection with acquisitions, dispositions or similar transactions;

- the limited payment of distributions, or failure to declare a distribution, on outstanding common units or other equity securities;

- any issuance of additional common units or other equity securities, and any resulting dilution or decline in the market price of any such securities;
- potential changes in tax laws which may impair the ability to obtain capital funds through investment partnerships;
- 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;
- changes and potential changes in the regulatory and enforcement environment in the areas in which we conduct business;
- 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;
- potential incurrence of significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment;
- access to sufficient amounts of carbon dioxide for tertiary recovery operations;
- uncertainties with respect to the success of drilling wells at identified drilling locations;
- acquisitions may potentially prove to be worth less than we paid, or provide less than anticipated proved reserves;
- ability to identify all risks associated with the acquisition of oil and natural gas properties, or existing wells, and the sufficiency of indemnifications we receive from sellers to protect us from such risks;
- expirations of undeveloped leasehold acreage;
- uncertainty regarding leasing operating expenses, general and administrative expenses and funding and development costs;
- exposure to financial and other liabilities of the managing general partners of the investment partnerships;
- the ability to comply with, and the potential costs of compliance with, new and existing federal, state, local and other laws and regulations applicable to our business and operations;
- restrictions on hydraulic fracturing;
- exposure to new and existing litigation;
- development of alternative energy resources; and
- the effects of a cyber event or terrorist attack.

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 “Item 1A: Risk Factors” in this report. 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.

PART I

ITEM 1: BUSINESS
Overview

We are a publicly-traded master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas, crude oil and natural gas liquids (“NGL”), with operations in basins across the United States. We are a leading sponsor and manager of tax-advantaged investment partnerships (“Drilling Partnerships”), in which we co-invest, to finance a portion of our natural gas, crude oil and natural gas liquids production activities.

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, 2015, our estimated proved reserves were 921 Bcfe, including the reserves net to our equity interest in our Drilling Partnerships. Of our estimated proved reserves, approximately 82% were proved developed and approximately 66% were natural gas. For the year ended December 31, 2015, our average daily net production was approximately 266.4 MMcfe. Through December 31, 2015, we own production positions in the following areas:

- the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas where we have ownership interests in approximately 736 proved developed wells and 10 proved undeveloped locations totaling 139 Bcfe of total proved reserves with average daily production of 60.6 MMcfe for the year ended December 31, 2015;
- the coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Central Appalachian Basin in southern West Virginia and southwestern Virginia, and Arkoma where we have ownership interests in approximately 3,646 proved developed wells and 18 proved undeveloped locations totaling 378 Bcfe of total proved reserves with average daily production of 129.5 MMcfe for the year ended December 31, 2015;
- the Appalachia Basin, including the Marcellus Shale and the Utica Shale where we have ownership interests in approximately 8,620 wells, including approximately 271 wells in the Marcellus Shale, and 90 Bcfe of total proved reserves with average daily production of 34.1 MMcfe for the year ended December 31, 2015;
- the Eagle Ford Shale in southern Texas where we have ownership interests in approximately 27 proved developed wells and 72 proved undeveloped locations in the Eagle Ford Shale totaling 115 Bcfe of total proved reserves with average daily production of 9.4 MMcfe for the year ended December 31, 2015;
- the Rangely field in northwest Colorado where we have non-operated ownership interests in approximately 400 wells in the Rangely field and 170 Bcfe of total proved reserves with average daily production of 15.8 MMcfe for the year ended December 31, 2015;
- the Mississippi Lime and Hunton plays in northwestern Oklahoma where we have ownership interests in approximately 108 proved developed wells and 18 Bcfe of total proved reserves with average daily production of 12.3 MMcfe for the year ended December 31, 2015; and
- other operating areas, including the Chattanooga Shale in northeastern Tennessee, the New Albany Shale in southwestern Indiana and the Niobrara Shale in northeastern Colorado in which we have an aggregate 11 Bcfe of total proved reserves with average daily production of 4.8 MMcfe for the year ended December 31, 2015.

We seek to create substantial value by executing our strategy of acquiring properties with stable, long-life production, relatively predictable decline curves and lower risk development opportunities. Over the three years ended December 31, 2015, we have acquired significant net proved reserves and production through the following transactions:

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EP Energy Acquisition. On July 31, 2013, we completed the acquisition of certain assets from EP Energy E&P Company, L.P ("EP Energy") for approximately $709.6 million in net cash (the "EP Energy Acquisition"). The coal-bed methane producing natural gas assets included approximately 3,000 producing wells generating net production of approximately 119 MMcfed on the date of acquisition from EP Energy on approximately 700,000 net acres in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming.

- GeoMet Acquisition—On May 12, 2014, we completed the acquisition of certain assets from GeoMet, Inc. for approximately $97.9 million in cash, net of purchase price adjustments, with an effective date of January 1, 2014 (the "GeoMet Acquisition"). The coal-bed methane producing natural gas assets include approximately 70 Bcfe of proved reserves with over 400 active wells generating 22 MMcfed on the date of acquisition in the Central Appalachian Basin in West Virginia and Virginia.

- Rangely Acquisition—On June 30, 2014, we completed the acquisition of a 25% non-operated net working interest in oil and NGL producing assets, representing approximately 47 Mmboe reserves for $408.9 million in cash with an effective date of April 1, 2014 (the “Rangely Acquisition”). The assets are located in the Rangely field in northwest Colorado. The acquired assets are expected to provide us with a stable, high margin cash flow stream with a low-decline profile (average 3-4% annual decline rate over the past 15 years). The asset position is a tertiary oil recovery project using CO2 flood activity, and the production mix is 90% oil, with the remainder coming from NGLs. Chevron Corporation (NYSE: CVX; “Chevron”) will continue as operator of the assets.
- Eagle Ford Acquisition—On November 5, 2014, we and our affiliate, Atlas Growth Partners, L.P. (“AGP”), completed the acquisition of interests in oil and natural gas assets in the Eagle Ford Shale in South Central Atascosa County, Texas, including 4,000 operated gross acres and net reserves of 12 Mmboe as of July 1, 2014 (the “Eagle Ford Acquisition”). The purchase price was $342.0 million, our initial share of the aggregate purchase price was $206.5 million and AGP’s share was $135.5 million. The Eagle Ford Acquisition had an effective date of July 1, 2014. On July 8, 2015, AGP sold to us, for a purchase price of $1.4 million, AGP’s interest in a portion of the acreage it acquired in the Eagle Ford Acquisition. On September 21, 2015, we and AGP, in accordance with the terms of the Eagle Ford shared acquisition and operating agreement, agreed that we would fund AGP’s remaining two deferred purchase price installments of $16.2 million and $20.1 million to be paid on September 30, 2015 and December 31, 2015, respectively. In conjunction with this agreement, AGP assigned us a portion of its non-operating Eagle Ford assets that had an allocated value (as such value was agreed upon by the sellers and the buyers in connection with the Eagle Ford Acquisition) equal to both installments to be paid by us. The transaction was approved by our and AGP’s respective conflicts committees. As a result, our final share of the aggregate purchase price was $242.8 million and AGP’s share was $99.2 million.
- Arkoma Acquisition—On June 5, 2015, we completed the acquisition of ATLS’s coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the “Arkoma Acquisition”).

On February 27, 2015, our general partner, Atlas Energy Group, LLC (“Atlas Energy Group”; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. (“Atlas Energy”), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as “ATLS”). Atlas Energy Group manages our operations and activities through its ownership of our general partner interest. Concurrent with Atlas Energy Group’s unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. (“Targa”; NYSE: TRGP) (the “Atlas Merger”) and ceased trading. At December 31, 2015, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

Our operations include three reportable operating segments: gas and oil production, well construction and completion and other partnership management (see “Item 8: Financial Statements and Supplementary Data – Note 15”).

Competitive Strengths

We believe we are well-positioned to successfully execute our business strategy because of the following competitive strengths:

We have a high quality, long-lived reserve base. Our natural gas and oil properties are located principally in the Barnett and Eagle Ford shales, the Marble Falls play, the Mississippi Lime, the Raton, Black Warrior and Appalachian basins and the Rangely field, and are characterized by long-lived reserves, generally favorable pricing for our production and readily available transportation.

We have significant experience in making accretive acquisitions. Our management team has extensive experience in consummating accretive acquisitions. We believe we will be able to generate acquisition opportunities of both producing and non-producing properties through our management's extensive industry relationships. We intend to use these relationships and experience to find, evaluate and execute on acquisition opportunities.

We have significant engineering, geologic and management experience. Our technical team of geologists and engineers has extensive industry experience. We believe that we have been one of the most active drillers in our core operating areas and, as a result, that we have accumulated extensive geological and geographical knowledge about these areas. We have also added geologists and engineers to our technical staff who have significant experience in other productive basins within the continental United States, which enables us to evaluate and expand our core operating areas.

We are one of the leading sponsors of tax-advantaged Drilling Partnerships. We and our predecessor have sponsored limited and general partnerships to raise funds from investors to finance our development drilling activities since 1968, and we believe that we are one of the leading sponsors of such Drilling Partnerships in the country. We believe that our lengthy association with many of the broker-dealers that act as placement agents for our Drilling Partnerships provide us with a competitive advantage over entities with similar operations. We also believe that our sponsorship of Drilling Partnerships has allowed us to generate attractive returns on drilling, operating and production activities.

Fee-based revenues from our Drilling Partnerships and our substantially hedged production provide protection from commodity price volatility. Our Drilling Partnerships provide us with stable, fee-based revenues which diminish the influence of commodity price fluctuations on our cash flows. Because our Drilling Partnerships reimburse us on a cost-plus basis for drilling capital expenses, we are partially protected against increases in drilling costs. Our fees for managing our Drilling Partnerships accounted for approximately 15% of our segment margin for the year ended December 31, 2015. Additionally, our natural gas, crude oil and NGL production was hedged approximately 75% on an equivalent basis for the year ended December 31, 2015. As of December 31, 2015, we had approximately 160.2 Bcf, 4.3 Mmbbl and 0.1 Mmbbl of hedge positions, respectively, on our natural gas, crude oil and NGL production for 2016 through 2019.

Our partnership management business can improve the economic rates of return associated with our natural gas and oil production activities. A well drilled, net to our equity interest, in our partnership management business will provide us with an enhanced rate of return. For each well drilled in a partnership, we receive an upfront fee on the investors' well construction and completion costs and a fixed administration and oversight fee, which enhances our overall rate of return. We also receive monthly per well fees from the partnership for the life of each individual well, which also increases our rate of return.

Business Strategy

The key elements of our business strategy are:

Continue to manage our capital structure. We continually monitor the capital markets, our capital structure and our leverage ratios and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency.

Continue to manage our exposure to commodity price risk. To limit our exposure to changing commodity prices and enhance and stabilize our cash flow, we use financial hedges for a portion of our natural gas and oil production. We principally use fixed price swaps and collars as the mechanism for the financial hedging of our commodity prices.

Continue to maintain control of operations and costs. We believe it is important to be the operator of wells in which we or our Drilling Partnerships have an interest because we believe it will allow us to achieve operating efficiencies and control costs. As operator, we are better positioned to control the timing and plans for future enhancement and exploitation efforts, costs of enhancing, drilling, completing and producing the well, and marketing negotiations for our natural gas, oil, and NGL production to maximize both volumes and wellhead price. We were the operator of the vast majority of the properties in which we or our Drilling Partnerships had a working interest at December 31, 2015.

Expand our natural gas and oil production. We generate a significant portion of our revenue and net cash flow from natural gas and oil production. We believe our program of sponsoring Drilling Partnerships to exploit our acreage opportunities provides us with enhanced economic returns. For the five year period ended December 31, 2015, we raised over $0.6 billion from outside investors through our Drilling Partnerships. We intend to continue to develop our inventory of proved undeveloped locations through both sponsorship of Drilling Partnerships and direct well drilling to add value through reserve and production growth.

Expand our fee-based revenue through our sponsorship of Drilling Partnerships. We generate substantial revenue and cash flow from fees paid by the Drilling Partnerships to us for acting as the managing general partner. As we continue to sponsor Drilling Partnerships, we expect that our fee revenues from our drilling and operating agreements with our Drilling Partnerships will increase and will add stability to our revenue and cash flows.

Expand operations through strategic acquisitions. We continually evaluate opportunities to expand our operations through acquisitions of developed and undeveloped properties or companies that can increase our cash available for distribution. We will continue to seek strategic opportunities in our current areas of operation, as well as other regions of the United States.

Subsequent Events

Senior Note Repurchases. In January and February 2016, we executed transactions to repurchase portions of our senior unsecured notes. Through the end of February 2016, we have repurchased approximately $20.3 million of our 7.75% Senior Notes due 2021 and approximately $12.1 million of our 9.25% Senior Notes for approximately $5.5 million. As a result of these transactions, we will recognize approximately $25.9 million as gain on early extinguishment of debt in the first quarter of 2016.

Cash Distributions. On January 28, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of December 31, 2015. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of common units and Class C preferred limited units, respectively, was paid on February 12, 2016 to unitholders of record at the close of business on February 8, 2016.

On February 24, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of January 31, 2016. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of common units and Class C preferred limited units, respectively, will be paid on March 16, 2016 to unitholders of record at the close of business on March 9, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.5390625 per Class D Preferred Unit, or $2.2 million, for the period from October 15, 2015 through January 14, 2016 to Class D Preferred Unitholders of record as of January 4, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.671875 per Class E Preferred Unit, or $0.2 million, for the period from October 15, 2015 through January 14, 2016 to Class E Preferred Unitholders of record as of January 4, 2016.

NYSE Compliance. On January 12, 2016, we were notified by the NYSE that we were not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of the common units had been less than $1.00 for 30 consecutive trading days. We are working to remedy this situation in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE.

Recent Developments

Credit Facility Amendment. On November 23, 2015, we entered into an Eighth Amendment to the Second Amended and Restated Credit Agreement (the "Amendment") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amendment amends the Second Amended and Restated Credit Agreement dated July 31, 2013 (as amended from time to time, the "Credit Agreement"). Among other things, the Eighth Amendment:

- reduced the borrowing base under the Credit Agreement from $750.0 million to $700.0 million;
- increased the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- permits the incurrence of third lien debt subject to the satisfaction of certain conditions, including pro forma financial covenant compliance;
- upon the issuance of any third lien debt, reduces the borrowing base by 25% of the stated amount of such third lien debt (other than third lien debt that is used to refinance senior notes, second lien debt and other third lien debt);
- suspends compliance with a maximum ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) until the four fiscal quarter period ending March 31, 2017 and revised the

maximum ratio of Total Funded Debt to EBITDA to be 5.75 to 1.00 for the four quarter periods ending March 31, 2017 and June 30, 2017, 5.50 to 1.00 for the four quarter periods ending September 30, 2017 and December 31, 2017, 5.25 to 1.00 for the four quarter period ending March 31, 2018, and 5.00 to 1.00 for each four fiscal quarter period ending thereafter;

- replaced the requirement to maintain compliance with a maximum ratio of Senior Secured Total Funded Debt to EBITDA with a requirement to be in compliance with a maximum ratio of First Lien Debt (as defined in the Credit Agreement) to EBITDA of 2.75 to1.00; and
- reset the distribution to $0.15 per common unit and permits increases to the distribution per common unit if (a) the ratio of Total Funded Debt (as of such date) to EBITDA for the most recent four fiscal quarters is equal to or less than 5.00 to1.00 and (b) the borrowing base utilization is less than or equal to 85%, on a pro forma basis after giving effect to the distribution payments.

A Seventh Amendment to the Credit Agreement was entered into on July 24, 2015. Among other things, the Seventh Amendment redefined EBITDA.

A Sixth Amendment to the Credit Agreement was entered into on February 23, 2015. Among other things, the Sixth Amendment:

- reduced the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;
- permitted the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;
- rescheduled the May 1, 2015 borrowing base redetermination for July 1, 2015;
- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and
- revised the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

Funding of AGP's Eagle Ford Deferred Purchase Price. In connection with the Eagle Ford Acquisition, we guaranteed the timely payment of the deferred portion of the purchase price that was to be paid by AGP. Pursuant to the agreement between us and AGP, we had the right to receive some or all of the assets acquired by AGP in the event of its failure to contribute its portion of any deferred payments. In connection with the second installment payments, we and AGP amended the purchase and sale agreement to alter the timing and amount of the quarterly installment payments beginning on March 31, 2015 and ending December 31, 2015 (see "Overview – Eagle Ford Acquisition"). On September 21, 2015, we and AGP, in accordance with the terms of the Eagle Ford shared acquisition and operating agreement, agreed that we would fund AGP's remaining two deferred purchase price installments.

Arkoma Acquisition. On June 5, 2015, we completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). We 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, however, as the acquisition constituted a transaction between entities under common control, we retrospectively adjusted our consolidated financial statements for dates prior to the date of acquisition to reflect our results on a consolidated basis with the results of the Arkoma assets as of or at the beginning of the respective period.

Issuance of Common Units. In May 2015, in connection with the Arkoma Acquisition, we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.5 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our revolving credit facility.

Issuance of Preferred Units. In April 2015, we issued 255,000 of our 10.75% Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units") at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. We pay distributions on the Class E Preferred Units at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

Second Lien Term Loan Facility. On February 23, 2015, we entered into a Second Lien Credit Agreement (the "Second Lien Credit Agreement") with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"). The Term Loan Facility matures on February 23, 2020.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the last day of the applicable interest period (or, with respect to interest periods of more than three-months' duration, each day prior to the last day of such interest period that occurs at intervals of three months' duration after the first day of such interest period) for Eurodollar loans and quarterly for ABR loans.

Geographic and Geologic Overview

Through December 31, 2015, the majority of our production positions were in the following areas:

Barnett Shale/Marble Falls. The Barnett Shale and Marble Falls play are located east of the Bend Arch and west of the Quachita 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 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. As of December 31, 2015, we had an interest in approximately 746 Barnett Shale and Marble Falls wells. As of December 31, 2015, we had more than 88,077 net acres prospective for the Barnett Shale/Marble Falls play.

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.

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. As of December 31, 2015, we had an interest in approximately 271 Marcellus Shale wells, consisting of 228 vertical wells and 43 horizontal wells. As of December 31, 2015, we had an interest in eight horizontal Marcellus Shale wells in Northeastern Pennsylvania, all of which were developed through Drilling Partnerships. Also as of December 31, 2015, approximately 1,456 prospective Marcellus Shale acres remained undeveloped in Lycoming County, Pennsylvania. Our drilling activity in certain portions of the Appalachian Basin located in southwestern Pennsylvania, West Virginia and New York were limited until February 17, 2014 by the terms of the non-competition agreements between certain of ATLS's officers and directors and Chevron Corporation.

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. As of December 31, 2015, we had an interest in approximately 2,373 wells in Ohio including 12 horizontal Utica-Point Pleasant wells. As of December 31, 2015, we had approximately 1,394 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. As of December 31, 2015, we had more than 455,630 net undeveloped acres prospective for coal-bed methane. Also as of December 31, 2015, we operated 2,831 wells and had an interest in another 833 wells, all of which produce gas generated from coal.

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. As of December 31, 2015, we operated 973 wells at the Raton asset.

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. As of December 31, 2015, we operated 882 wells and had an interest in an additional 695 wells at the Black Warrior asset.

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. As of December 31, 2015, we operated 564 wells and had an interest in an additional 66 wells at the Arkoma asset.

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. As of December 31, 2015, we operated 412 wells and had an interest in an additional 72 wells in Virginia and West Virginia.

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.

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. As of December 31, 2015, we had 27 producing wells and 72 undeveloped locations in the Eagle Ford Shale.

Mississippi Lime/Hunton. The Mississippi Lime and Hunton formations are 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. As of December 31, 2015, we had an interest in approximately 78 Mississippi Lime wells and 30 Hunton wells.

Gas and Oil Production

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 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 three years ended December 31, 2015, 2014, and 2013:

	Years Ended December 31,		
	2015	2014	2013
Production per day:(1)(2)			
Natural gas (Mcfd)	216,613	238,054	163,971
Oil (Bpd)	5,139	3,436	1,329
Natural gas liquids (Bpd)	3,155	3,802	3,473
Total (Mcfed)	266,374	281,486	192,786

(1) “Mcfd” represents thousand cubic feet per day; “Mcfed” represents thousand cubic feet equivalents per day; and “Bpd” represents barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.
(2) 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 partnership and based on each partnership's proportionate net revenue interest in these wells.

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 for the years ended December 31, 2015, 2014, and 2013, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Years Ended December 31,		
	2015	2014	2013
Production revenues (in thousands):			
Natural gas revenue	$217,236	$318,920	$193,050
Oil revenue	122,273	110,070	44,160
Natural gas liquids revenue	17,490	41,061	36,394
Total revenues	$356,999	$470,051	$273,604
Average sales price:(1)			
Natural gas (per Mcf):			
Total realized price, after hedge(2)(3)	$3.41	$3.76	$3.48
Total realized price, before hedge(2)	$2.23	$3.93	$3.25
Oil (per Bbl):			
Total realized price, after hedge(3)	$84.30	$87.76	$91.01
Total realized price, before hedge	$44.19	$82.22	$95.88
NGLs (per Bbl):			
Total realized price, after hedge(3)	$22.40	$29.59	$28.71
Total realized price, before hedge	$12.77	$29.39	$29.43
Production costs (per Mcfe):(1)			
Lease operating expenses(4)	$1.34	$1.27	$1.08
Production taxes	0.19	0.27	0.18
Transportation and compression	0.24	0.25	0.25
Total	$1.76	$1.80	$1.50

(1) "Mcf" represents thousand cubic feet; "Mcfe" represents thousand cubic feet equivalents; and "Bbl" represents barrels.
(2) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effect of this subordination, the average realized gas sales prices were $3.36 per Mcf ($2.19 per Mcf before the effects of financial hedging), $3.67 per Mcf ($3.84 per Mcf before the effects of financial hedging), and $3.23 per Mcf ($3.00 per Mcf before the effects of financial hedging) for the years ended December 31, 2015, 2014 and 2013, respectively.
(3) Includes 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, consisting of $48.6 million associated with natural gas derivative contracts, $35.8 million associated with crude oil derivative contracts, and $8.3 million associated with natural gas liquids derivative contracts for the year ended December 31, 2015 (see "Item 8. Financial Statements – Note 8").

(4) 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. Including the effects of these costs, total lease operating expenses per Mcfe were $1.32 per Mcfe ($1.74 per Mcfe for total production costs), $1.25 per Mcfe ($1.77 per Mcfe for total production costs), and $1.00 per Mcfe ($1.42 per Mcfe for total production costs) for the years ended December 31, 2015, 2014 and 2013, respectively.

Partnership Management Business

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 sheets. 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 30%.

Over the last five years, we raised over $645.1 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
2015	$59.3	$ 17.6	$76.9
2014	166.8	71.0	237.8
2013	150.0	92.3	242.3
2012	127.1	54.4	181.5
2011	141.9	28.3	170.2
Total	$645.1	$ 263.6	$908.7

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.

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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. There were no exploratory wells drilled during the years ended December 31, 2015, 2014, and 2013.

	Years Ended December 31,		
	2015[3]	2014[3]	2013[3]
Gross wells drilled	28	129	103
Net wells drilled[1]	17	67	66
Gross wells turned in line[2]	36	119	117
Net wells turned in line[2]	15	64	80

(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 the years ended December 31, 2015, 2014 and 2013; there were no gross or net dry wells within our operating areas during the year ended December 31, 2015, 2014 and 2013.

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, 2015, we had the following ongoing drilling activities:

	Gross			Net		
	Spud	Total Depth	Completed	Spud	Total Depth	Completed
Eagle Ford - Horizontal	2	8	—	1	1	—

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 marketers directly or to third party plant operators who process and market 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 Transco Zone 5;
- 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 – Transco Zone 1;
- 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 attempt to sell the majority of our natural gas at monthly, fixed index prices and a smaller portion at index daily prices.

Crude Oil. Crude oil produced from our wells flows directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. The crude oil is typically sold at the prevailing spot market price for each region, less appropriate trucking/pipeline charges. 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 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 marketers 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 processing 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 for fixed and determinable quantities of NGLs in any future periods under existing contracts or agreements.

For the year ended December 31, 2015, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC accounted for approximately 21%, 15%, 11% and 11% of our total natural gas, oil, and NGL production revenues, respectively, with no other single customer accounting for more than 10% for this period.

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 marketer 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 contaminant removal 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 Interstate pipeline for purchase by Sequent Energy Management, L.P. 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 markets 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 our purchaser, Interconn Resources, L.L.C. and BP.

Mississippi Lime production is currently gathered, processed, fractionated, and marketed by one company, SemGas, and they return a Percent of Proceeds (“POP”) of the revenues it receives. That POP amount is 95%. 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.

We maintained a Pennsylvania Operating Services Agreement, pursuant to which a subsidiary of Chevron Corporation provided us (including Drilling Partnerships which we manage) with water disposal services with respect to certain wells in Pennsylvania in exchange for specified fees. We had an obligation to indemnify the provider against all claims and liabilities arising out of its provision of services under this agreement. On February 12, 2015, we received notice of termination from Chevron Corporation of the Pennsylvania Operating Services Agreement which terminated on August 12, 2015. Subsequent to the termination of the Pennsylvania Operating Services Agreement, we have utilized many of the same water hauling companies in the area but have had to pay higher disposal related fees.

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.

Markets

The availability of a ready market for natural gas, oil and natural gas liquids and the price obtained, depends upon numerous factors beyond our control, as described in “Item 1A: Risk Factors - Risks Relating to Our Business”. Product availability and price are the principal means of competition in selling natural gas, oil and NGLs.

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:

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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.

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. Under the auspices of the United States Environmental Protection Agency (the “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 for future regulation. 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, and that they hold all necessary and up-to-date permits, registrations and other authorizations to the extent that they are required under such laws and regulations. Although we and our subsidiaries do not believe the current costs of managing wastes to be significant, any more stringent regulation of natural gas and oil exploitation 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" 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, wastes or hydrocarbons 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. There may be evidence that petroleum spills or releases have occurred at some of the properties owned or leased by us. However, none of these spills or releases appears to be material to our financial condition and we believe all of them have been or will be appropriately remediated. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties, and the substances disposed or released on them, may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including waste disposed of by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform remedial plugging or pit closure operations to prevent future contamination.

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 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. Further, much of our natural gas extraction activity utilizes a process called hydraulic fracturing, which results in water discharges that must be treated and disposed of in accordance with applicable regulatory requirements.

On April 21, 2014, the U.S. Army Corps of Engineers ("USACE") and the EPA proposed a rule that would define 'Waters of the United States' ("WOTUS"), i.e., the scope of waters protected under the Clean Water Act, in light of several U.S. Supreme Court opinions (U.S. v. Riverside Bayview, Rapanos v. United States, and Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers). The public comment period concluded on November 14, 2014 and the EPA received hundreds of thousands of comments on the proposed rule. On May 27, 2015, the EPA and USACE announced the final rule redefining the extent of the agencies' jurisdiction over WOTUS, and the final rule was published in the Federal Register on June 29, 2015 with an effective date of August 28, 2015. The final rule was immediately challenged by multiple parties, including individual states, in both United States District Courts and U.S. Circuit Courts of Appeals. On October 9, 2015, the 6th Circuit Court of Appeals found that the petitioners, totaling 18 states, demonstrated a "substantial possibility of success on the merits of the claim" and issued a nationwide stay of the WOTUS final rule. Currently, this nationwide stay is in place and the litigation in both the U.S. District and Circuit Courts is ongoing. Additionally, there have been legislative efforts by the General Assembly to nullify the rule, specifically a joint resolution of Congress passed under authority of the Congressional Review Act that was vetoed by President Obama on January 19, 2016. As drafted, the final rule is broader in scope then the current rule, and will increase the costs of compliance and result in additional permitting requirements for some of our existing or future facilities.

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 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. Such laws and regulations may require obtaining pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions. Air permits contain various emissions and operational limitations, and may require specific emission control technologies to limit emissions. Various air quality regulations are periodically reviewed by the EPA and are amended as deemed necessary. The EPA may also issue new regulations based on changing environmental concerns.

Recent revisions to federal Clean Air Act rules impose additional emissions control requirements and practices on 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.

OSHA and Other Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act, or “OSHA,” and comparable state statutes. 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. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

On October 22, 2015, the EPA responded to an October 24, 2012 petition to the EPA requesting that the oil and gas extraction industrial sector be added to the sectors with reporting requirements covered by Section 313 of the Emergency Planning and Community Right-to-Know Act (the Toxics Release Inventory or “TRI”). In its response, the EPA stated that it intends to propose a rulemaking that would subject natural gas processing facilities that employ more than 10 people to annual TRI reporting, but that the EPA will not propose that well sites, compressor stations, pipelines, and other oil and gas extraction industrial sector facilities be subject to TRI reporting.

Additionally, the White House Office of Management and Budget received OSHA’s final “Occupational Exposure to Crystalline Silica” rule on December 21, 2015. The final rule has not been published, but is expected to follow OSHA’s proposed rule from September 12, 2013 that would impose a new exposure limit for silica and with it various new requirements. The federal 2015 Fall Unified Agenda and Regulatory Plan lists February 2016 as the target release date for the final rulemaking. OSHA has previously addressed respirable silica from the oil and gas industry operations back in December 2014 when it released a “Hydraulic Fracturing and Flowback Hazards Other than Respirable Silica” safety alert. If finalized, the rule would likely result in significant costs for the oil and gas industry to comply with the new requirements.

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. However, Congress has been actively considering climate change legislation. More directly, the EPA has begun regulating greenhouse gas emissions under the federal Clean Air Act. In response to 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), the EPA made a final determination that greenhouse gases endangered public health and welfare, 74 Fed. Reg. 66,496 (Dec. 15, 2009). This finding led to the regulation of greenhouse gases under the Clean Air Act. Currently, the EPA has promulgated two final rules relating to greenhouse gases that will affect our businesses.

First, the EPA promulgated the so-called “Tailoring Rule” which established emission thresholds for greenhouse gases under the Clean Air Act permitting programs, 75 Fed. Reg. 31,514 (June 3, 2010). Both the federal preconstruction review program, known as “Prevention of Significant Deterioration” (“PSD”), and the operating permit program are now implicated by emissions of greenhouse gases. These programs, as modified by the Tailoring Rule, could require some new facilities to obtain a PSD permit depending on the size of the new facilities. In addition, existing facilities as well as new facilities that exceed the emissions thresholds could be required to obtain the requisite operating permits.

On June 23, 2014, the United States Supreme Court ruled on challenges to the Tailoring Rule in the case of Utility Air Regulatory Group v. EPA, 134 S. Ct. 2427 (2014). The Court limited the applicability of the PSD program and Tailoring Rule to only new sources or modifications that would trigger PSD for another criteria pollutant such that projects cannot trigger PSD based solely on greenhouse gas emissions. However, if PSD is triggered for another pollutant, greenhouse gases could be subject to a control technology review process. The Court’s decision also means that sources cannot trigger a federal operating permit requirement based solely on greenhouse gas emissions. Overall, the impact of the Tailoring Rule after the Court’s decision is that it is unlikely to have much, if any, impact on our operations. However, the EPA is still in the process of responding to the Court’s decision through rulemakings.

Second, the EPA finalized its Mandatory Reporting of Greenhouse Gases rule in 2009, 74 Fed. Reg. 56,260 (Oct. 2009). Subsequent revisions, additions and clarifications were promulgated, including a rule subpart specifically addressing the natural gas industry. This particular subpart was most recently revised in October 2015, 80 Fed. Reg. 64262 (Oct. 22, 2015), when the EPA finalized changes to calculation methods, monitoring and data reporting requirements, and other provisions. Shortly thereafter, in January 2016, the EPA proposed additional revisions to the broader Greenhouse Gas Reporting for public comment. In general, the Greenhouse Gas Reporting Rule requires certain industry sectors that emit greenhouse gases above a specified threshold to report greenhouse gas emissions to the EPA on an annual basis. The natural gas industry is covered by the rule and requires annual greenhouse gas emissions to be reported by March 31 of each year for the emissions during the preceding calendar year. This rule imposes additional obligations on us to determine whether the greenhouse gas reporting applies and if so, to calculate and report greenhouse gas emissions.

In addition to these existing rules, the Obama Administration announced in January 2015 that it was developing additional rules to curb greenhouse gas emissions from the oil and gas sector, as part of a new national strategy for reducing methane emissions from the sector by 40 – 45% from 2012 levels by the year 2025. This national methane reduction strategy targeting the oil and gas sector is related to the Obama Administration’s broader Climate Action Plan of 2013. Multiple federal agencies, including the EPA and the U.S. Department of the Interior’s Bureau of Land Management, which we refer to as the BLM, are involved in implementing the national methane reduction strategy.

In August 2015, the EPA proposed a broad suite of regulatory measures to implement the national methane reduction strategy, as well as to reduce emissions of ozone-forming volatile organic compounds (“VOCs”) and clarify air permitting requirements for the oil and gas sector. The proposed measures include: (1) a revised New Source Performance Standards (“NSPS”) rule for oil and natural gas production, transmission, and distribution that would expand existing requirements for sources of VOCs and establish new requirements for sources of methane; (2) draft Control Techniques Guidelines that direct states to adopt regulations for reducing VOC emissions from existing oil and gas facilities in certain ozone nonattainment areas and states in the Ozone Transport Region; (3) a Federal Implementation Plan for certain oil and gas operations located in Indian country; and (4) a rule defining the circumstances in which oil and gas equipment and activities are to be considered part of a source that is subject to “major source” permitting requirements under the Clean Air Act. The EPA accepted public comments on these proposals through early December 2015. The proposals are expected to be finalized in 2016.

Consistent with the Obama Administration’s methane reduction strategy, on January 22, 2016, BLM released a proposed rule to update standards for venting, flaring, and equipment leaks from oil and gas production activities on onshore Federal and Indian leases. BLM’s existing requirements are more than three decades old. According to BLM, the proposed rule would ensure that operators use modern best practices to minimize waste of produced natural gas and reduce emissions of methane and VOCs.

There are also ongoing legislative and regulatory efforts to encourage the use of cleaner energy technologies. While natural gas is a fossil fuel, it is considered to be more benign, from a greenhouse gas standpoint, than other carbon-based fuels, such as coal or oil. Thus, future regulatory developments could have a positive impact on our business to the extent that they either decrease the demand for other carbon-based fuels or position natural gas as a favored fuel.

In addition to domestic regulatory developments, the United States is a participant in multi-national discussions intended to deal with the greenhouse gas issue on a global basis. To date, those discussions have not resulted in the imposition of any specific regulatory system, but such talks are continuing and may result in treaties or other multi-national agreements (e.g., the “Paris Agreement,” reached at the United Nations Conference on Climate Change in December 2015) that could have an impact on our business.

Finally, the scientific community continues to engage in a healthy debate as to the impact of greenhouse gas emissions on planetary conditions. For example, such emissions may be responsible for increasing global temperatures, and/or enhancing the frequency and severity of storms, flooding and other similar adverse weather conditions. We do not believe that these conditions are having any material current adverse impact on our business, and we are unable to predict at this time, what, if any, long-term impact such climate effects would have.

Energy Policy Act. Much of our natural gas extraction activity utilizes a process called hydraulic fracturing. The Energy Policy Act of 2005 amended the definition of “underground injection” in the Federal Safe Drinking Water Act of 1974, or “SDWA.” This amendment effectively excluded hydraulic fracturing for oil, gas or geothermal activities from the SDWA permitting requirements, except when “diesel fuels” are used in the hydraulic fracturing operations. Recently, this subject has received much regulatory and legislative attention at both the federal and state level and we anticipate that the permitting and compliance requirements applicable to hydraulic fracturing activity are likely to become more stringent and could have a material adverse impact on our business and operations. For instance, the EPA released its revised final guidance document on SDWA underground injection control permitting for hydraulic fracturing using diesel fuels in February 2014, along with responses to selected substantive public comments on the EPA’s previous draft guidance, a fact sheet and a memorandum to the EPA's regional offices regarding implementation of the guidance. The process for implementing the EPA's final guidance document may vary across states depending on the regulatory authority responsible for implementing the SDWA UIC program in each state.

The U.S. Senate and House of Representatives considered legislative bills in the 111th, 112th, and 113th Sessions of Congress that, if enacted, would have repealed the SDWA permitting exemption for hydraulic fracturing activities. Titled the "Fracturing Responsibility and Awareness of Chemicals Act," or "Frac Act," the legislative bills as proposed could have potentially led to significant oversight of hydraulic fracturing activities by federal and state agencies. The Frac Act was re-introduced in the current 114th Session of Congress and referred to the Committee on Environment and Public Works; if enacted into law, the legislation as proposed could potentially result in significant regulatory oversight, which may include additional permitting, monitoring, recording and recordkeeping requirements for us.

We believe our operations are in substantial compliance with existing SDWA requirements. However, future compliance with the SDWA could result in additional requirements and costs due to the possibility that new or amended laws, regulations or policies could be implemented or enacted in the future.

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.

Oil Spills and Hydraulic Fracturing. 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.

A number of federal agencies, including the EPA and the Department of Interior, are currently evaluating a variety of environmental issues related to hydraulic fracturing. For example, the EPA is conducting a study that evaluates any potential effects of hydraulic fracturing on drinking water and ground water. On December 9, 2013, the EPA's Hydraulic Fracturing Study Technical Roundtable of subject-matter experts from a variety of stakeholder groups met to discuss the work underway to answer the hydraulic fracturing study's key research questions. Individual research projects associated with the EPA's study were published in July 2014. On June 4, 2015, the EPA released its draft "Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources" (the "Draft Assessment"), in addition to nine new peer-reviewed scientific reports that formed the basis for certain findings included in the Draft Assessment. The scope of the Draft Assessment focuses on potential impacts to drinking water resources by hydraulic fracturing, specifically the following water activities that the EPA has identified as the "hydraulic fracturing water cycle" in the Draft Assessment: water acquisition from ground or surface waters; chemical mixing at the well site; well injection of hydraulic fracturing fluids; the collection and handling of wastewater from hydraulic fracturing (such as flowback and produced water); and wastewater treatment and waste disposal. The EPA revealed in its Draft Assessment that it has not found any evidence that hydraulic fracturing activities are performed in a way that leads to widespread, systemic impacts on drinking water resources. The EPA did identify specific instances where hydraulic fracturing activities may have led to impacts to drinking water; however, the EPA noted that those instances are minimal when compared to the number of hydraulically fractured wells in the United States. Notice of the Draft Assessment was published in the June 5, 2015 Federal Register, and several public teleconference calls and a public meeting were held by the EPA's Science Advisory Board (SAB) to discuss the Draft Assessment. On January 7, 2016, the SAB released a Draft Review of the EPA's Draft Assessment. The Draft Review includes many recommendations to the EPA that SAB believes the EPA should consider to improve the Draft Assessment. These recommendations include, but are not limited to: revising its draft finding that the EPA found no "evidence that hydraulic fracturing mechanisms have led to widespread, systemic impacts on drinking water resources," as the SAB found the statement to be ambiguous and therefore require clarification and additional explanation; adding further discussion on the Pavillion, Wyoming; Parker County, Texas; and Dimock, Pennsylvania investigations; collecting and add new data regarding the chemicals used during hydraulic fracturing and the content of flowback water; and adding Best Management Practices and suggested improvements to each stage of the hydraulic fracturing process.

BLM proposed a rule on May 11, 2012 that includes provisions requiring disclosure of chemicals used in hydraulic fracturing and construction standards for hydraulic fracturing on federal lands. On May 24, 2013, BLM published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands. On March 26, 2015, BLM issued a final rule updating the regulations governing hydraulic fracturing on federal and Indian lands. Among the many new requirements, the final rule requires operators planning to conduct hydraulic fracturing to design and implement a casing and cementing program that follows best practices and meets performance standards to protect and isolate usable water, as well as requires operators to monitor cementing operations during well completion. Additionally, the final rule requires that companies publicly disclose the chemicals used in the hydraulic fracturing process, subject to limited exceptions for trade secret materials; comply with safety standards for storage of produced water in rigid enclosed, covered, or netted and screened above-ground tanks, with very limited exceptions allowing use of pits that must be approved by BLM on a case-by-case basis; and submit detailed information to the BLM on proposed operations, including but not limited to well geology, location of faults and fractures, estimated volume of fluid to be used, and estimated direction and length of fractures. The final rule also provides that for certain circumstances in which specific state or tribal regulations are equally or more protective than the BLM's new rules, the state or tribe may obtain a variance for that specific regulation. The final rule was set to go into effect on June 24, 2015. However on June 23, 2015, the U.S. District Court for the District of Wyoming announced a stay on the effective date of the rule in State of Wyoming v. Dep't of Interior, No. 2:15-cv-00043, a lawsuit that involves several states and industry associations who requested that the Court grant a preliminary injunction of the final rule. On September 30, 2015, the U.S. District Court granted the preliminary injunction, thus enjoining the final rule.

In addition, state and local conservancy districts and river basin commissions have all previously exercised their various regulatory powers to curtail and, in some cases, place moratoriums on hydraulic fracturing. State regulations include express inclusion of hydraulic fracturing into existing regulations covering other aspects of exploration and production and specifically 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.

Local regulations, which may be preempted by state and federal regulations, have included, but have not been limited to, the following, which may extend to all operations including those beyond hydraulic fracturing:

- noise control ordinances;
- traffic control ordinances;
- limitations on the hours of operations; and
- mandatory reporting of accidents, spills and pressure test failures.

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, 2015, approximately 619 ATLS employees provided direct support to our operations. After the closing of the Atlas Energy Merger, all of our personnel were employed by our general partner. Some of the officers of our general partner may spend a substantial amount of time managing the business and affairs of our general partner and its affiliates other than us and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

Available Information

We make our periodic reports under the Securities Exchange Act of 1934, 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.atlasresourcepartners.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (“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.

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ITEM 1A: RISK FACTORS

You should carefully consider each of the following risks, which we believe are the principal risks that we face and of which we are currently aware, and all of the other information in this report. Some of the risks described below relate to our business, while others relate principally to the securities markets and ownership of our limited partnership interests. Partnership 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. The risks and uncertainties our company faces are not limited to those set forth in the risk factors described below. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business. In addition, past financial performance may not be a reliable indicator of future performance, and historical trends should not be used to anticipate results or trends in future periods. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

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;
- 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, 2015, the NYMEX Henry Hub natural gas index price ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $61.43 per Bbl to a low of $34.73 per Bbl. Between January 1, 2016 and February 29, 2016, the NYMEX Henry Hub natural gas index price ranged from a high of $2.47 per MMBtu to a low of $1.71 per MMBtu, and West Texas Intermediate oil prices ranged from a high of $36.76 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, results of operations, and ability to continue cash distributions to unitholders. We may use various derivative instruments in connection with anticipated oil and natural gas sales to reduce the impact of commodity price fluctuations. 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.

Oil prices and natural gas prices have declined substantially from historical highs and may remain depressed for the foreseeable future. Approximately 17% of our 2015 total revenues were derived from oil and condensate sales. Approximately 81% of our 2015 total production was natural gas, on a “Mcf-equivalent” basis. Any additional decreases in prices of oil and natural gas may adversely affect our cash generated from operations, results of operations, financial position, and our ability to pay distributions, perhaps materially.

During the year ended December 2015, the spot WTI market price at Cushing, Oklahoma has declined from a high of $61.43 per Bbl to a low of $34.73 per Bbl. During the nine years prior to December 31, 2015, natural gas prices at Henry Hub have ranged from a high of $13.31 per MMBtu in 2008 to a low of $1.76 per MMBtu in 2015. Between January 1, 2015 and December 31, 2015, the Henry Hub spot market price of natural gas ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu. The reduction in prices has been caused by many factors, including substantial increases in U.S. oil and natural gas production and reserves from unconventional (shale) reservoirs, without an offsetting increase in demand. The International Energy Agency (“IEA”) forecasts steady or a slightly declining U.S. production growth and a slowdown in global demand growth in 2016.

This environment could cause the prices for oil and natural gas to remain at current levels or to fall to even lower levels. If prices for oil and natural gas continue to remain depressed for lengthy periods, we may be required to write down the value of our oil and natural gas properties, and some of our undeveloped locations may no longer be economically viable. In addition, sustained low prices for oil and natural gas will negatively impact the value of our estimated proved reserves and the amount that we are allowed to borrow under our bank credit facility (as a result of borrowing base redeterminations) and reduce the amounts of cash we would otherwise have available to pay expenses, fund capital expenditures, make distributions to our unitholders, and service our indebtedness.

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.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Our key operated project areas are located in active drilling areas in the Mississippi Lime, Marble Falls, Utica Shale and Marcellus Shale, and many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of natural gas and oil in these areas.

Our operations require liquidity for normal operating expenses, servicing our debt, capital expenditures and distributions to our limited partners and general partners.

Our primary liquidity requirements, in addition to normal operating expenses, are for servicing our debt, capital expenditures and distributions to our limited partners and general partner. In general, we expect to fund our liquidity needs through cash flow from operations (including our hedges), bank borrowings, the Drilling Partnerships and equity and debt offerings. Due to the steep decline in commodity prices, our ability to obtain funding in the equity or capital markets has been, and may continue to be, constrained, and there can be no assurances that our liquidity requirements will continue to be satisfied given current commodity prices. If our sources of liquidity are not sufficient to fund our current or future liquidity needs, including as a result of any future borrowing base redetermination, we may be required to take other actions, such as:

- refinancing, restructuring or reorganizing all or a portion of our debt or capital structure;
- obtaining alternative financing;
- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital;
- liquidating all or a portion of our hedge portfolio;
- seeking additional partners to develop our assets;
- reducing our planned capital program;
- continuing to take, and potentially increasing, our cost saving measures to reduce costs, including renegotiation contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs; or
- revising or delaying our other strategic plans.

Our ability to take these actions will depend on, among other things, the conditions of the capital markets and our financial condition at such time. Due to the steep decline in commodity prices, we may not be able to obtain funding in the equity or capital markets on terms we find acceptable as the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide any new funding. 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.

We are currently primarily dependent on our credit facilities for liquidity. Any further reduction of the borrowing base under our revolving credit facility could reduce or eliminate our ability to borrow under the facility and may require us to repay indebtedness under our credit facilities earlier than anticipated, which would adversely impact our liquidity.

Subject to amounts reserved in the discretion of our Board of Directors to provide for the proper conduct of our business, our limited partnership agreement provides that we make distributions to our unitholders of available cash. Therefore, we have not historically accumulated cash to preserve liquidity and have been dependent on the capital markets and our credit facilities for liquidity. Although our Board of Directors approved a reduction of our common unit distributions, if the constrained capital markets conditions continue, we will continue to be primarily reliant on our credit facilities, and to the extent available, the excess of net cash provided by operating activities, for liquidity.

At December 31, 2015, there was approximately $103.8 million of available borrowing capacity under our revolving credit facility. The revolving credit facility is subject to semi-annual redeterminations of its borrowing base, based primarily on reserve reports, and our next redetermination date is in May 2016. Downward revisions of our oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant. For example, as a result of lower commodity prices, in November 2015, the borrowing base decreased from $750 million to $700 million. Continued low commodity prices and the possible reserve write-downs that may result, along with the maturity schedule of our hedges, may impact future redeterminations.

There can be no assurance that our lenders will not reduce the borrowing base to an amount below our outstanding borrowings, which would require us to repay a portion of outstanding borrowings or deposit additional collateral to eliminate such deficiency. In such event, we may be required to enter into discussions with our lenders or take other actions, including those described in the preceding risk factor, to satisfy our obligations as a result of such a borrowing base redetermination. 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, or the indentures governing our senior notes, 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 or holders or our notes, as applicable, 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 a significant portion 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.

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 and affect our ability to pay distributions on our units.

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 expansion capital expenditures, including with funds from third-party sources, we will be unable to expand our business operations, and may not generate sufficient revenue or have sufficient available cash to pay distributions on our units.

Economic conditions and instability in the financial markets could negatively impact our business which, in turn, could impact the cash we have to make distributions to our unitholders.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the Chinese economy, and the United States real estate market have contributed to increased economic uncertainty and diminished expectations 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 and ability to pay distributions could be impacted which in turn could affect the amount of distributions that we are able to make to our unitholders. 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.

Our debt obligations could restrict our ability to pay cash distributions and have a negative impact on our financing options and liquidity position.

Our debt obligations could have important consequences to us and our investors, including:

- requiring a substantial portion of our cash flow to make interest payments on this debt;
- making it more difficult to satisfy debt service and other obligations;
- increasing the risk of a future credit ratings downgrade of our debt, which could increase future debt costs and limit the future availability of debt financing;
- increasing our vulnerability to general adverse economic and industry conditions;
- reducing the cash flow available to fund capital expenditures and other corporate purposes and to grow our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry;
- placing us at a competitive disadvantage relative to our competitors that may not be as leveraged with debt;
- limiting our ability to borrow additional funds as needed or take advantage of business opportunities as they arise; and
- limiting our ability to pay cash distributions.

To the extent that we incur additional indebtedness, the risks described above could increase.

Covenants in our debt documents restrict our business in many ways.

Our credit facilities and the indentures governing our senior notes contain various restrictive covenants that limit our ability to, among other things:

- incur additional debt or liens or provide guarantees in respect of obligations of other persons;
- pay distributions or redeem or repurchase our securities;
- prepay, redeem or repurchase debt;
- make loans, investments and acquisitions;
- enter into hedging arrangements;
- sell assets;
- enter into certain transactions with affiliates; and
- consolidate or merge with or into, or sell substantially all of our assets to, another person.

In addition, our debt documents 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 or the indentures governing our senior notes, we may be required to enter into discussions with our lenders or take other actions, such as: refinancing, restructuring or reorganizing all or a portion of our debt or capital structure; obtaining alternative financing; selling assets; reducing or delaying capital investments; seeking to raise additional capital; liquidating all or a portion of our hedge portfolio; reducing our planned capital program; continuing to take, and potentially increasing, our cost saving measures to reduce costs, including renegotiation contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs; or revising or delaying our other strategic plans, which may negatively impact the price of our securities. A breach of any of the covenants in our credit facilities or the indentures governing our senior notes, respectively, 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 or holders or our notes, as applicable, 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 a significant portion 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. 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.

Our cash distribution policy limits our ability to grow.

Because we distribute our available cash, if any, rather than reinvesting it in our business, our growth may not be as significant as businesses that reinvest their available cash to expand ongoing operations, and we may not have enough cash to meet our needs if any of the following events occur:

- an increase in our operating expenses;
- an increase in general and administrative expenses;
- an increase in principal and interest payments on our outstanding debt;
- a reduction in the amount we are allowed to borrow under our bank credit facility (including as a result of borrowing base redeterminations); or
- an increase in working capital requirements.

If we issue additional units or incur debt to fund our operations, acquisitions and expansion or investment capital expenditures, the payment of distributions on those additional units or interest on that debt could increase the risk that we will be unable to maintain or continue our per unit distribution level.

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. Natural gas liquids 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 year ended December 31, 2015, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC accounted for approximately 21%, 15%, 11% and 11% of our total natural gas, crude oil and natural gas liquids production revenue, respectively, with no other single customer accounting for more than 10% for this period. 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 available for distributions to unitholders 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 available for distribution to our unitholders 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, 2015, leases covering approximately 4,702 of our 742,944 net undeveloped acres, or 0.6%, are scheduled to expire on or before December 31, 2016. An additional 1.6% of our net undeveloped acres are scheduled to expire in 2017 and 0.2% in 2018. 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.

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 and our ability to pay distributions.

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.

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 generating 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.

The recent decrease in natural gas and oil prices, or any further decrease 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. During the year ended December 31, 2015, we recognized $966.6 million of asset impairment primarily related to oil and gas properties in the Barnett, Coal-bed Methane, Rangely, Southern Appalachia, Marcellus and Mississippi Lime operating areas, and unproved acreage in the New Albany Shale, which were impaired due to lower forecasted commodity prices, net of $85.8 million of future hedge gains reclassified from accumulated other comprehensive income.

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. 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 general 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 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.

In addition, 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.

Due to the accounting treatment of derivative contracts, increases in prices for natural gas, crude oil and NGLs could result in non-cash balance sheet reductions and non-cash losses in our statement of operations.

We account for our derivative contracts by applying the mark-to-market accounting treatment required for these derivative contracts. We could recognize incremental derivative liabilities between reporting periods resulting from increases or decreases in reference prices for natural gas, crude oil and NGLs, which could result in us recognizing a non-cash loss in our combined statements of operations and a consequent non-cash decrease in our equity between reporting periods. Any such decrease could be substantial. In addition, we may be required to make cash payments upon the termination of any of these derivative contracts.

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, or 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. The CFTC recently 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 and reduce our ability to make distributions to unitholders.

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.

Acquired properties may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

One of our growth strategies is to capitalize on opportunistic acquisitions of natural gas reserves. However, reviews of acquired properties are often incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. A detailed review of records and properties also may not necessarily reveal existing or potential problems, and may not permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Any unidentified problems could result in material liabilities and costs that negatively affect our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable and may be limited by floors and caps on such indemnity.

We may not identify all risks associated with the acquisition of oil and natural gas properties, or existing wells, and any indemnifications we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Our business strategy focuses on acquisitions of undeveloped oil and natural gas properties that we believe are capable of production. We have acquired and may make additional acquisitions of undeveloped oil and gas properties from time to time, subject to available resources. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and other liabilities and other factors. Generally, it is not feasible for us to review in detail every individual property involved in a potential acquisition. In making acquisitions, we generally focus most of our title, environmental and valuation efforts on the properties that we believe to be more significant, or of higher-value. Even a detailed review of properties and records may not reveal all existing or potential problems, nor would it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. In addition, we do not inspect in detail every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we perform a detailed inspection. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable or may be limited by floors and caps, and the financial wherewithal of such seller may significantly limit our ability to recover our costs and expenses. Any limitation on our ability to recover the costs related any potential problem could materially impact our financial condition and results of operations.

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 in 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, results of operations and cash available for distribution.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is 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 in certain circumstances. For example:

- On December 17, 2014, New York Governor Andrew Cuomo's administration said it would ban hydraulic fracturing for shale gas development throughout the state. Dr. Howard Zucker, the Acting Commissioner of Health, announced that the state Department of Health completed its long-awaited public health review report, which recommended prohibiting hydraulic fracturing in New York. Dr. Zucker cited significant uncertainties regarding risks to public health in concluding that hydraulic fracturing should not proceed in New York until more research is completed. On June 29, 2015 the New York State Department of Environmental Conservation officially prohibited hydraulic fracturing in New York State by issuing its legally-binding Findings Statement. According to the Findings Statement, the Department of Conservation concluded that "there are no feasible or prudent alternatives that would adequately avoid or minimize adverse environmental impacts and that address the scientific uncertainties and risks to public health" associated with hydraulic fracturing.
- Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. On February 14, 2012, legislation was passed in Pennsylvania requiring, among other things, disclosure of chemicals used in hydraulic fracturing. We refer to this legislation as the "2012 Oil and Gas Act." To implement the new legislative requirements, on December 14, 2013 the Pennsylvania Department of Environmental Protection, which we refer to as PADEP, proposed amendments to its environmental regulations at 25 Pa. Code Chapter 78, Subchapter C, pertaining to environmental protection performance standards for surface activities at oil and gas well sites. Pursuant to a legislative bill that passed in July 2014 as a companion to Pennsylvania's budget for 2014 to 2015, PADEP bifurcated its proposed 25 Pa. Code Chapter 78 regulations into two parts. . As proposed, 25 Pa. Code Chapter 78 will apply to conventional wells and 25 Pa. Code Chapter 78A will apply to unconventional wells. On January 6, 2016, PADEP released a final-form rulemaking package of the Chapters 78 and 78a amendments. PADEP identified the key provisions of the final-form rulemaking package to include, but not be limited to, new requirements for operators to address potential impacts to public resources, as well as requirements for operators to identify and monitor abandoned, orphaned and inactive wells prior to hydraulic fracturing. It will also mandate new containment practices and protection water resources, which includes rules for operator response to spill and remediation, and many other changes that will impact our operations. Pennsylvania's Environmental Quality Board is scheduled to meet February 3, 2016 to consider the proposed rulemakings, and PADEP anticipates that the final form rulemaking will likely be finalized in early summer 2016. Additionally, PADEP announced in June 2014 that it also intends to propose amendments to its present environmental regulations at 25 Pa. Code Chapter 78, Subchapters D (relating to well drilling, operation and plugging) and H (relating to underground gas storage). It is anticipated that these proposed amendments will be released in 2016. In January 2015, PADEP issued the results of its Technologically Enhanced Naturally Occurring Radioactive Materials Study, which analyzed levels of radioactivity

associated with oil and gas development in Pennsylvania. Initiated in January 2013, the study evaluated radioactivity levels in flowback waters, treatment solids, and drill cuttings, in addition to the transportation, storage and disposal of these materials. According to the study, PADEP concluded that there is little potential for harm to workers or the public from radiation exposure due to oil and gas development, as well as provided recommendations for further study to be conducted.

- Ohio has in recent years expanded its oil and gas regulatory program. In June 2012, Ohio passed legislation that made several significant amendments to the state's oil and gas laws, including additional permitting requirements, chemical disclosure requirements, and site investigation requirements for horizontal wells. In June 2013, legislation was adopted imposing sampling requirements and disposal restrictions on certain drilling wastes containing naturally occurring radioactive material and requiring the state regulatory authority to adopt rules on the design and operation of facilities that store, recycle, or dispose of brine or other oil and natural gas related waste materials. In July 2015, the regulatory authority adopted rules imposing detailed construction standards on well pads, and in April 2014, Ohio announced new standard drilling permit conditions to address concerns regarding seismic activity in certain parts of the state.
- For wells spudded January 1, 2014 and after, the Texas Railroad Commission adopted new rules regarding well casing, cementing, drilling, completion and well control for ensuring hydraulic fracturing operations do not contaminate nearby water resources. Recent Railroad Commission rules and regulations focus on prevention of waste, as evidenced by regulations relating to the commercial recycling of produced water and/or hydraulic fracturing flowback fluid approved in September 2012, and more stringent permitting for venting/flaring of casinghead gas and gas well gas beginning in January 2014.
- A West Virginia rule that became effective July 1, 2013 imposes more stringent regulation of horizontal drilling and was promulgated to provide further direction in the implementation and administration of the Natural Gas Horizontal Well Control Act that became effective on December 14, 2011. In 2014, West Virginia revised its solid waste regulations to allow landfills to increase their tonnage limits specifically for natural gas drilling wastes, along with requiring more stringent controls and radiation testing of landfills located in the state.

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 in particular. Recent changes regarding local land use restrictions in Pennsylvania occurred because of decisions of the Pennsylvania Supreme and Commonwealth Courts. On December 19, 2013, when the Pennsylvania Supreme Court issued its Robinson Township v. Commonwealth of Pennsylvania ruling, which invalidated key sections of the 2012 Oil and Gas Act that placed limits on the regulatory authority of local governments. Additionally, the Pennsylvania Supreme Court remanded a number of issues to the Commonwealth Court for further decision. On July 17, 2014, the Commonwealth Court ruled on the remanded issues. The cumulative effect of the Supreme and Commonwealth Court rulings is that all of the challenged provisions relating to local ordinances contained in the 2012 Oil and Gas Act are invalid, except for the definitions section and most of the updated preemption language in the 2012 Oil and Gas Act that was included from the previous 1984 Oil and Gas Act. The total impact of these rulings in Robinson Township, which is ongoing before the Supreme Court, are not clear and will occur over an extended period of time. An immediate impact of the rulings has been increased regulatory impediments and disputes at the local government level, as well as validity challenges initiated by private landowners alleging that local ordinances do not adequately protect health, safety, and welfare. Additionally, there is a pending challenge by an industry association regarding the Robinson Township decision and PADEP's use of its Public Resources Form and Pennsylvania Natural Diversity Index Policy based on a provision of the 2012 Oil and Gas Act (58 C.S. § 3215(c)). The petitioner is seeking a declaration from the Supreme Court that PADEP is enjoined from application and enforcement of that provision pursuant to the Court's Robinson Township ruling.

On June 30, 2014, the New York Court of Appeals issued its opinion in Wallach v. Town of Dryden affirming local zoning laws adopted by two upstate municipalities that prohibited oil and gas-related activities within their borders. Specifically, the Court of Appeals ruled that there was nothing within the plain language, statutory scheme and legislative history of the New York Oil, Gas and Solution Mining Law that manifested an intent by the legislature to preempt a municipality's home rule authority to regulate land use. On October 16, 2014, the New York Court of Appeals denied a request by the petitioner – the bankruptcy trustee for Norse Energy – to re-hear arguments in the case. If state, local or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. Generally, Federal, state and local restrictions and requirements are applied consistently to similar types of producers (e.g., conventional, unconventional, etc.), regardless of size of the producing company.

Although, to date, the hydraulic fracturing process has not generally been subject to regulation at the federal level, there are certain governmental reviews either under way or being proposed that focus on environmental aspects of hydraulic fracturing practices, and some federal regulation has taken place. A few of these initiatives are listed here, although others may exist now or be implemented in the future. In April 2012, President Obama established an Interagency Working Group to Support Safe and Responsible Development of Unconventional Domestic Natural Gas Resources with the purpose of coordinating the policies and activities of agencies regarding unconventional gas development. The United States Environmental Protection Agency (the “EPA”) has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel as an additive under the Safe Drinking Water Act. In May 2012, the EPA issued draft permitting guidance for oil and gas hydraulic fracturing activities using diesel fuel. In February 2014, the EPA released its revised final guidance document on Safe Drinking Water Act underground injection control permitting for hydraulic fracturing using diesel fuels, along with responses to selected substantive public comments on the

EPA's previous draft guidance, a fact sheet and a memorandum to the EPA's regional offices regarding implementation of the guidance. The process for implementing the EPA's final guidance document may vary across the states depending on the regulatory authority responsible for implementing the Safe Drinking Water Act underground injection control program in each state. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, the EPA is currently studying the potential impacts of hydraulic fracturing on drinking water and groundwater, and, in fact, released a Draft Assessment on June 4, 2015.

In 2013, the EPA indicated that it intended to propose a draft water quality criteria document that would update the aquatic life water quality criteria for chloride by the summer of 2014. However, the EPA has yet to propose the draft water quality criteria document and it has not provided an updated timeframe for the proposal. On April 7, 2015, the EPA published its "Effluent Limitations Guidelines and Standards for the Oil and Gas Extraction Point Source Category" in the Federal Register, and accepted comments through July 17, 2015. As proposed, the regulations would establish pretreatment standards for discharges of wastewater pollutants from onshore unconventional oil and gas extractive facilities to publicly-owned treatment works. The EPA has proposed pretreatment standards for existing and new sources that would prohibit the indirect discharge of wastewater pollutants associated with onshore unconventional gas extraction facilities. Additionally, the EPA published its "Final 2014 Effluent Guidelines Program Plan" on August 4, 2015 and confirmed its schedule for the aforementioned ongoing unconventional oil and gas extraction effluent guideline rulemaking, as well as announced a final decision to continue its detailed study to investigate centralized waste treatment facilities that accept oil and gas extraction wastewaters. On May 11, 2012, the U.S. Department of the Interior, Bureau of Land Management published a proposed rule that includes provisions requiring disclosure of chemicals used in hydraulic fracturing and construction standards for hydraulic fracturing on federal and Indian lands. On May 24, 2013, the Bureau of Land Management published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands. On March 26, 2015, BLM issued a final rule updating the regulations governing hydraulic fracturing on federal and Indian lands that was set to go into effect on June 24, 2015. Subsequently on June 23, 2015 in a lawsuit filed by several states and industry associations before the U.S. District Court for the District of Wyoming (State of Wyoming v. Dep't of Interior, No. 2:15-cv-00043), a stay of the effective date of the BLM's pending rule was lodged. The petitioners specifically requested that Court grant a preliminary injunction of the final rule and, on September 30, 2015, the U.S. District Court granted the preliminary injunction thereby enjoining the final rule.

Certain members of the U.S. Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, and Congress has asked the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing. In addition, Congress requested the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. On December 16, 2013, the U.S. Energy Information Administration published an abridged version of its Annual Energy Outlook 2014 with projections to 2040 report, with the full report released on May 7, 2014. A subsequent Annual Energy Outlook 2015 was released on April 14, 2015, with the next coming June 2016. These ongoing proposed studies, depending on their degree of pursuit and any meaningful results obtained, could result in initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or one or more other regulatory mechanisms. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform hydraulic fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could be significantly affected.

Some of the potential effects of changes in Federal, state or local regulation of hydraulic fracturing operations 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.

Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of greenhouse gas emissions. Facilities required to obtain Prevention of Significant Deterioration permits because of their potential criteria pollutant emissions may be required to comply with “best available control technology” standards for greenhouse gases. These regulations could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources.

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. In the absence of such federal climate legislation, 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. In addition, the Obama Administration announced its Climate Action Plan in 2013, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas industry. The Obama Administration announced a formal methane reduction strategy in January 2015, and is taking actions to implement the strategy (see “Item 1. Business- Environmental Matters and Regulation - Greenhouse Gas Regulation and Climate Change”). Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such 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.

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.

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

In 2012, the EPA 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. The NSPS rule was most recently revised in August 2015, 80 Fed. Reg. 48262 (Aug. 12, 2015), and it will be revised again when the EPA finalizes the rulemaking to implement the national methane reduction strategy (see “Item 1. Business- Environmental Matters and Regulation - Greenhouse Gas Regulation and Climate Change”). In November 2015, the EPA issued a formal request for data and information which suggests that the agency may revise the NESHAP rules in the near future. In addition to these EPA rules, BLM released a proposed rule in January 2016 to reduce oil and gas industry emissions and minimize waste of produced gas from Federal and Indian leases.

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.

Overall, 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.

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 regulation. 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, results of operations and our ability to make distributions to our unitholders.

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

A significant portion of our natural gas extraction activity utilizes 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. For example, Pennsylvania's 2012 Oil and Gas Act requires the development, submission and approval of a water management plan before withdrawing or using water from water sources in Pennsylvania to drill or hydraulically fracture an unconventional well. The requirements of these plans continue to be modified by proposed amendments to state regulations and agency policies and guidance. For Pennsylvania operations located in the Susquehanna River Basin, the Susquehanna River Basin Commission regulates consumptive water uses, water withdrawals, and the diversions of water into and out of the Susquehanna River Basin, and specific approvals are required prior to initiating drilling activities. In June 2012, Ohio passed legislation that established a water withdrawal and consumptive use permit program in the Lake Erie watershed. If certain withdrawal thresholds are triggered due to water needs for a particular project, we will be required to develop a Water Conservation Plan and obtain a withdrawal permit for that project. West Virginia also requires that if a certain amount of water is withdrawn water management plans are required and/or registration and reporting requirements are triggered.

Our ability to collect and dispose of flowback and produced water will affect our production, and potential increases in the cost of wastewater treatment 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 gas and oil. For example, in July 2012, the Ohio Department of Natural Resources promulgated amendments to the regulations governing disposal wells in Ohio. The rules provide the Department of Natural Resources with the authority to require certain testing as part of the process for obtaining a permit for the underground injection of produced water, and require all new disposal wells to be equipped with continuous pressure monitors and automatic shut off devices.

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. For the year ended December 31, 2015, we estimated that the impact fee for our wells, including the wells in our Drilling Partnerships will approximately $643,000. This is compared to an impact fee of approximately $1.0 million for the year ended December 31, 2014, an impact fee of approximately $1.7 million for the year ended December 2013 and an impact fee of approximately $2.0 for year ended December 31, 2012.

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

How we plan, design, drill, install, operate and abandon natural gas 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 that requires operators to cover reserve pits during the cleanup phase of the pit, if the pit is open more than 90 days.

Complying with these requirements is expected to increase costs and prompt delays in natural gas production. There can be no assurance that we will be able to obtain all necessary permits and, if obtained, that the costs associated with obtaining such permits will not exceed those that previously had been estimated. 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. These enforcement actions may be handled by the EPA and/or the appropriate state agency. In some cases, the EPA has taken a heightened role in enforcement activities targeting the oil and gas extraction sector. For example, in 2011, the EPA Region III requested the lead on all oil and gas related violations in the United States Army Corps of Engineers' Pittsburgh District. The EPA, the United States Army Corps of Engineers' and the United States Department of Justice have been actively pursuing instances of unpermitted stream and wetland impacts, particularly for activities occurring in West Virginia. We also understand that the EPA has taken an increased interest in assessing operator compliance with the Spill Prevention, Control and Countermeasures regulations, set forth at 40 CFR Part 112.

Certain environmental statutes, including RCRA, CERCLA, the federal Oil Pollution Act and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where certain substances have been disposed of or otherwise released, whether caused by our operations, the past operations of our predecessors or third parties. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

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 restoration 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 under our respective insurance policies.

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 us 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 will be subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas and oil we may produce and sell. A major risk inherent in a drilling plan is the need to obtain drilling permits 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 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. For example, Pennsylvania’s 2012 Oil and Gas Act imposes significant, costly requirements on the natural gas industry, including the imposition of increased bonding requirements and impact fees for unconventional gas wells, based on the price of natural gas and the age of the unconventional gas well. PADEP’s proposed regulatory amendments associated with this legislation, when finalized will affect how natural gas operations are conducted in Pennsylvania. Moreover, PADEP has indicated that more regulatory amendments are likely to be proposed in 2016. West Virginia has promulgated regulations associated with its existing Horizontal Well Control Act and has developed new aboveground storage tank laws that are being applied broadly and impose stringent requirements that affect the natural gas industry. 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.

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 partnerships. We raised $59.3 million, $166.8 million and $150.0 million in 2015, 2014, and 2013, respectively. In the future, we may not be successful in raising funds through these Drilling Partnerships at the same levels that it 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.

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, both the Obama Administration's budget proposal for fiscal year 2017 and other recently introduced legislation include proposals 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.

Fee-based revenues may decline if we are unsuccessful in sponsoring new Drilling Partnerships.

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.

Our revenues may decrease if investors in our Drilling Partnerships do not receive a minimum return.

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. For the year ended December 31, 2015, $1.7 million of our revenues, net of corresponding production costs, were subordinated, which reduced our cash distributions received from the Drilling Partnerships. For the year ended December 31, 2014, the subordinated amount, net of corresponding production costs, was $5.3 million and for the year ended December 31, 2013, it was $9.6 million.

We or one of our subsidiaries may be exposed to financial and other liabilities as the managing general partner in Drilling Partnerships.

We or one of our subsidiaries serves as the managing general partner of the Drilling Partnerships and will be the managing general partner of new Drilling Partnerships that we sponsor. As a general partner, we or one of our subsidiaries will be contingently liable for the obligations of the partnerships to the extent that partnership assets or insurance proceeds are insufficient. We have agreed to indemnify each investor partner in the Drilling Partnerships from any liability that exceeds such partner's share of the Drilling Partnership's assets.

Our historical financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

Some of the historical financial information that we have included in this report may not necessarily reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. The general and administrative expenses reflected in the financial statements for Atlas Energy E&P Operations include an allocation for certain corporate functions historically provided by Atlas Energy, Inc. These allocations were based on what we and Atlas Energy, Inc. considered to be reasonable reflections of the historical utilization levels of these services required in support of the business. We have not adjusted the historical financial statements for Atlas Energy E&P Operations to reflect changes that occurred in our cost structure and operations as a result of our transition to becoming a stand-alone public company. Therefore, the financial statements of Atlas E&P Operations and our historical financial information may not necessarily be indicative of what our financial position, results of operations or cash flows will be in the future.

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 the Ownership of Our Units

If prices of our common and/or preferred units decline, our unitholders could lose a significant part of their investment.

The market price of our units 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 and securities of publicly traded limited partnerships and limited liability 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 units; 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 and/or preferred units.

Sales of our units may cause our unit price to decline.

Sales of substantial amounts of our units in the public market, or the perception that these sales may occur, could cause the market price of our units to decline. In addition, the sale of these units could impair our ability to raise capital through the sale of additional units.

At December 31, 2015, Atlas Energy Group, our general partner, owned approximately 20.96 million common and 3.75 million preferred limited partner units, representing an approximately 23.3% limited partner ownership interest in us. Our general partner is free to sell some or all of these common units at any time. In addition, we have agreed to register under the U.S. Securities Act of 1933, as amended, which we refer to as the Securities Act, any sale of common units held by our general partner and its affiliates. These registration rights allow our general partner and its affiliates to request registration of their common units and to include any of those units in a registration of other securities by us. If our general partner and its affiliates were to sell a substantial portion of their units, it could reduce the market price of our outstanding common units. Additionally, unless previously converted, all of our Class C preferred units, including all of our general partner's preferred units, will convert into common units on a one-for-one basis on July 31, 2016. At December 31, 2015, there were 3,749,986 Class C preferred units outstanding.

An increase in interest rates may cause the market price of our units to decline.

Like all equity investments, an investment in our units is subject to risks. Investors may be willing to accept these risks in exchange for possibly receiving a higher rate of return than may otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partner interests. Reduced demand for our units resulting from investors seeking other investment opportunities may cause the trading price of our units to decline.

We may not have sufficient cash flow from operations to pay the minimum quarterly distribution following the establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient cash flow from operations each quarter to pay the minimum quarterly distribution. Under the terms of our partnership agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserve amounts that our general partner establishes to provide for the conduct of our business, including operations, future capital expenditures and our anticipated future credit needs, future debt service requirements and future cash distributions to our unitholders and the holders of the distribution incentive rights. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas and oil we produce;
- the price at which we sell our natural gas and oil;
- the level of our operating costs;
- our ability to acquire, locate and produce new reserves;
- the results of our hedging activities;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable on it; and
- the level of our capital expenditures.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- our ability to make working capital borrowings to pay distributions;
- the cost of acquisitions, if any;
- fluctuations in our working capital needs;
- timing and collectability of receivables;
- restrictions on distributions imposed by lenders;
- payments to our general partner; and
- the strength of financial markets and our ability to access capital or borrow funds.

The amount of cash we have available for distribution to unitholders, if any, depends primarily on our cash flow and not solely on profitability.

The amount of cash that we have available for distribution, if any, depends primarily on our cash flow, including cash reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses, and we may not make cash distributions during periods when we record net income.

We have the right to borrow to make distributions. Repayment of these borrowings will decrease cash available for future distributions, and covenants in our debt documents have restrictions and financial covenants that may restrict our ability to pay distributions to our unitholders.

Our partnership agreement allows us to borrow to make distributions. We may make short term borrowings under our credit facility, which we refer to as working capital borrowings, to make distributions. The primary purpose of these borrowings would be to mitigate the effects of short term fluctuations in our working capital that would otherwise cause volatility in our quarter to quarter distributions.

Our credit facilities and the indentures governing our senior notes contain various restrictive covenants that limit our ability to, among other things, pay distributions or redeem or repurchase our securities. In addition, our debt documents 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. These restrictions and financial covenants may restrict our ability to pay distributions to our unitholders.

Cost reimbursements due to our general partner for services provided may be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to our partnership agreement, our general partner receives reimbursement for the provision of various general and administrative services for our benefit. Payments for these services may be substantial, are not subject to any aggregate limit, and will reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

If we do not pay distributions on our preferred units in any fiscal quarter, we will be unable to pay distributions on our common units until all unpaid preferred unit distributions have been paid, and our common unitholders are not entitled to receive distributions for such prior periods.

If we do not pay the required distributions on our preferred units, we will be unable to pay distributions on our common units. Additionally, because distributions to our preferred unitholders are cumulative, we will have to pay all unpaid accumulated preferred distributions before we can pay any distributions to our common unitholders. Also, because distributions to our common unitholders are not cumulative, if we do not pay distributions on our common units with respect to any quarter, our common unitholders will not be entitled to receive distributions covering any prior periods.

With limited exceptions, our partnership agreement restricts the voting rights of unitholders that own 20% or more of our common units.

Our partnership agreement prohibits any person or group that owns 20% or more of our common units then outstanding, other than our general partner, its affiliates and transferees, from voting on any matter.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts committee of its board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner, as the initial holder of our incentive distribution rights, has the right, at any time when it has received incentive distributions at the highest level to which it is entitled (50.0%) for each of the prior four consecutive fiscal quarters and the amount of each such distribution did not exceed adjusted operating surplus for such quarter, to reset the initial target distribution levels at higher levels based on our cash distributions at the time of the exercise of the reset election. Following any reset election, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. If our general partner transfers all or a portion of our incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this reset right.

If a reset election is made, then the holder of the incentive distribution rights will be entitled to receive additional common units from the partnership equal to the number of common units that would have entitled the holder of such additional common units to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the incentive distribution rights in the prior two quarters. We anticipate that the holder of our incentive distribution rights may exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such reset. It is possible, however, that the reset right is exercised at a time when the holder is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels.

Our unitholders who fail to furnish certain information requested by our general partner or who our general partner determines are not eligible citizens may not be entitled to receive distributions in kind upon our liquidation and their units will be subject to redemption.

We have the right to redeem all of the units of any holder that is not an eligible citizen if we are or become subject to federal, state, or local laws or regulations that, in the determination of our general partner, create a substantial risk of cancellation or forfeiture of any property in which we have an interest because of the nationality, citizenship or other related status of any limited partner. Our general partner may require any limited partner or transferee to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within a reasonable period after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, the limited partner may be treated as a non-citizen assignee. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation. Furthermore, we have the right to redeem all of the units of any holder that is not an eligible citizen or fails to furnish the requested information.

Units held by persons who are non-taxpaying assignees will be subject to the possibility of redemption.

If our general partner determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on our ability to operate our assets or generate revenues from our assets, then our general partner may adopt such amendments to our partnership agreement as it determines are necessary or appropriate to obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant) and permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rate that can be charged to customers by our subsidiaries or who fails to comply with the procedures instituted by our general partner to obtain proof of the U.S. federal income tax status.

Holders of our units have limited voting rights and are not entitled to elect our general partner or its board of directors.

Unlike the holders of common stock in a corporation, our common unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Common unitholders do not elect our general partner or the members of its board of directors on an annual or other continuing basis. The board of directors of our general partner is elected by its unitholders. Furthermore, the vote of the holders of at least two-thirds of all outstanding common units is required to remove our general partner. As a result of these limitations on the ability of holders of our common units to influence the management of our company, the price at which the common units trade could be diminished.

Additionally, holders of the preferred units have no voting rights with respect to matters that generally require the approval of voting unitholders. Voting rights for holders of preferred units exist primarily with respect to voting on amendments to our certificate of formation and partnership agreement that materially and adversely affect the rights of the holders of preferred units or authorizing, increasing or creating additional classes or series of our units that are senior to the preferred units.

Our general partner's interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of our unitholders, either before March 13, 2022 in a merger or in a sale of all or substantially all of its assets, or after March 13, 2022 under any circumstances if such transfer is otherwise in compliance with our partnership agreement. In addition, our general partner may transfer all or a portion of its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase distributions to unitholders over time as it would if it had retained ownership of the incentive distribution rights.

We may issue an unlimited number of additional units, including units that are senior to the common units and parri passu with the preferred units, without unitholder approval, which would dilute unitholders' ownership interests. Any additional issuance will not dilute the general partner interest in us.

Our partnership agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting, including additional preferred units and any securities parity with the preferred units without any vote of the holders of the preferred units (except where the cumulative distributions on the preferred units or any parity securities are in arrears) and without the approval of our common unitholders. The issuance by us of additional units or other equity interests of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units and preferred units may decline.

Moreover, the issuance of additional common units will not dilute the holder of our class A units. The class A units represent a 2% general partner interest in us, and the holder of such class A units will be entitled to 2% of our cash distributions without any obligation to make future capital contributions to us. The 2% sharing ratio of the class A units will not be reduced if we issue additional common units in the future. Because the 2% sharing ratio will not be reduced if we issue additional common units, and in order to ensure that each class A unit represents the same percentage economic interest in us as one common unit, if we issue additional common units, we will also issue to our general partner, for no additional consideration and without any requirement to make a capital contribution, an additional number of class A units so that the total number of outstanding class A units after such issuance equals 2% of the sum of the total number of common units and class A units after such issuance.

In addition, the payment of distributions on any additional units may increase the risk that we will not be able to make distributions at our prior per unit distribution levels. To the extent new units are senior to our common units, their issuance will increase the uncertainty of the payment of distributions on our common units.

As a limited partnership, we qualify for, and rely on, exemptions from certain corporate governance requirements of the NYSE rules.

Under the NYSE listing standards, a limited partnership is exempt from certain NYSE corporate governance requirements, including:

- the requirement that a majority of the board of directors consists of independent directors;
- the requirement that we have a nominating/governance committee that is comprised entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;

- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee’s purpose and responsibilities; and
- the requirement for an annual performance evaluation of the nominating/governance and compensation committees.

We utilize some of the foregoing exemptions from the corporate governance requirements of the NYSE listing standards. As a result, we do not have a nominating/governance committee or a compensation committee.

In addition, NYSE rules requiring that stockholder approval be obtained prior to certain issuances of equity securities do not apply to limited partnerships.

Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

Our units may be delisted from the New York Stock Exchange.

On January 12, 2016, we were notified by the NYSE that we are not in compliance with NYSE’s continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of our common units had been less than $1.00 for 30 consecutive trading days. We are required to remedy this in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE, and, if we are unable to do so, our preferred units that are currently listed on the NYSE and our common units may be delisted by the NYSE. If delisting occurs, it could be more difficult to buy or sell our units and the price of our units could decline. Delisting could also affect our ability to raise capital. If we were delisted from the NYSE, we could seek to move trading of the units to the NYSE MKT exchange or OTC. These methods of trading could significantly impair our ability to raise new capital.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than two-thirds of the outstanding class of any limited partner interests, our general partner will have the right, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of such class of limited partner interests held by unaffiliated persons at a price equal to the greater of (1) the highest cash price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and (2) the average of the daily closing prices of the limited partner interests of such class over the 20 trading days preceding the date three days before the date of the mailing of the exercise notice for such call right. You may be required to sell your units at an undesirable time or price. You may also incur a tax liability upon a sale of your units.

The credit and risk profiles of our general partner could adversely affect our credit ratings and profile.

The credit and risk profiles of our general partner may be factors in credit evaluations of us as a publicly traded limited partnership due to the significant influence of our general partner over our business activities, including our cash distributions, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our general partner, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness.

Unitholders’ liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Unitholders could be liable for any and all of our obligations as if they were a general partner if, among other potential reasons:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- unitholders' right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes "control" of our business.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17–607 of the Delaware Revised Uniform Limited Partnership Act (“Delaware Act”), we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to us are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement.

The preferred units represent perpetual equity interests in us.

The preferred units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As a result, holders of the preferred units may be required to bear the financial risks of an investment in the preferred units for an indefinite period of time. In addition, the preferred units rank junior to all our current and future indebtedness (including indebtedness outstanding under our revolving credit facility, our second lien term loan facility and our senior notes), and any other senior securities we may issue in the future with respect to assets available to satisfy claims against us.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for U.S. federal income tax purposes or we were to become subject to a material amount of entity-level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available for distribution.

The anticipated after-tax benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter that affects us.

We are currently treated as a partnership for federal income tax purposes, which requires that 90% or more of our gross income for every taxable year consist of qualifying income, as defined in Section 7704 of the Internal Revenue Code. Qualifying income is defined as income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy and timber). We may not meet this requirement or current law may change so as to cause, in either event, us to be treated as a corporation for federal income tax purposes or otherwise be subject to federal income tax. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35% and would likely pay state income tax at varying rates. Distributions to you would generally be taxed as corporate distributions, and no income, gain, loss, deduction or credit would flow through to you. Because a tax may be imposed on us as a corporation, our cash available for distribution to our unitholders could be reduced. Therefore, our treatment as a corporation could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and therefore result in a substantial reduction in the value of our common units.

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Current law or our business may change so as to cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. Our limited partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local or foreign income tax purposes, the minimum quarterly distribution amount and the incentive distribution amounts will be adjusted to reflect the impact of that law on us.

Unitholders are required to pay taxes on their share of our taxable income, including their share of ordinary income and capital gain upon dispositions of properties by us or cancellation of debt, even if they do not receive any cash distributions from us. A unitholder’s share of our taxable income, gain, loss and deduction, or specific items thereof, may be substantially different than the unitholder’s interest in our economic profits.

Our unitholders are required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

For example, we have repurchased approximately $20.3 million of our 7.75% Senior Notes and approximately $12.1 million of our 9.25% Senior Notes at prices lower than face amount (See “Subsequent Events”). These repurchases will, and other similar transactions in the future may, result in cancellation of debt income that will be allocated to our unitholders. Some or all of our unitholders may be allocated substantial amounts of such taxable income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect to each unitholder would depend on the unitholder's individual tax position with respect to the units; however, taxable income allocations from us, including cancelation of debt income, increase a unitholder’s tax basis in their units.

In addition, we may sell a portion of our properties and use the proceeds to pay down debt or acquire other properties rather than distributing the proceeds to our unitholders, and some or all of our unitholders may be allocated substantial taxable income with respect to that sale. A unitholder’s share of our taxable income upon a disposition of property by us may be ordinary income or capital gain or some combination thereof. Even where we dispose of properties that are capital assets, what otherwise would be capital gains may be recharacterized as ordinary income in order to “recapture” ordinary deductions that were previously allocated to that unitholder related to the same property.

A unitholder’s share of our taxable income and gain (or specific items thereof) may be substantially greater than, or our tax losses and deductions (or specific items thereof) may be substantially less than, the unitholder’s interest in our economic profits. This may occur, for example, in the case of a unitholder who purchases units at a time when the value of our units or of one or more of our properties is relatively low or a unitholder who acquires units directly from us in exchange for property whose fair market value exceeds its tax basis at the time of the exchange. Cash distributions from us decrease a unitholder’s tax basis in its units, and the amount, if any, of excess distributions over a unitholder’s tax basis in its units will, in effect, become taxable income to the unitholder, above and beyond the unitholder’s share of our taxable income and gain (or specific items thereof).

Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (“IRAs”) and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

A successful IRS contest of the U.S. federal income tax positions we take may harm the market for our common units, and the costs of any contest will reduce cash available for distribution.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may disagree with some or all of those positions. Any contest with the IRS may lower the price at which our common units trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

We treat each holder of our common units as having the same tax benefits without regard to the common units held. The IRS may challenge this treatment, which could reduce the value of the common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of existing U.S. Treasury regulations. A successful IRS challenge to those positions could reduce the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

Tax gain or loss on disposition of our common units could be more or less than expected.

If a unitholder sells their common units, they will recognize a gain or loss equal to the difference between the amount realized and the adjusted tax basis in those common units. Prior distributions and the allocation of losses, including depreciation deductions, to the unitholder in excess of the total net taxable income allocated to them, which decreased the tax basis in their common units, will, in effect, become taxable income to them if the common units are sold at a price greater than their tax basis in those common units, even if the price is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder.

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a 12-month period.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A constructive termination results in the closing of our taxable year for all unitholders and in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, may result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns, and unitholders receiving two Schedule K-1s, for one fiscal year and the cost of the preparation of these returns will be borne by all unitholders.

Unitholders may be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We do business and own assets in Alabama, Colorado, Indiana, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia and West Virginia. As we make acquisitions or expand our business, we may do business or own assets in other states in the future. It is the responsibility of each unitholder to file all U.S. federal, foreign, state and local tax returns that may be required of such unitholder.

The IRS may challenge our tax treatment related to transfers of units, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. If the IRS were to challenge this method or new U.S. Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between us and our public unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of our unitholders and our general partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of our common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain on the sale of common units by our unitholders and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of our unitholders without the benefit of additional deductions.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Treatment of distributions on our preferred units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our preferred units than the holders of our common units.

The tax treatment of distributions on our preferred units is uncertain. We will treat the holders of preferred units as partners for tax purposes and will treat distributions on the preferred units as guaranteed payments for the use of capital that will generally be taxable to the holders of preferred units as ordinary income. Although a holder of preferred units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions quarterly. Otherwise, the holders of Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction. Nor will we allocate any share of our nonrecourse liabilities to the holders of preferred units. If the preferred units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of preferred units.

A holder of preferred units will be required to recognize gain or loss on a sale of units equal to the difference between the unitholder's amount realized and tax basis in the units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such preferred units. Subject to general rules requiring a blended basis among multiple limited partnership interests, the tax basis of a preferred unit will generally be equal to the sum of the cash and the fair market value of other property paid by the unitholder to acquire such preferred unit. Gain or loss recognized by a unitholder on the sale or exchange of a preferred unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of preferred units will not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we will have the ability to elect to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that we will choose to make such election or that such election will be effective in all circumstances. If we are unable to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, or we choose not to do so, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable to us for tax years beginning on or prior to December 31, 2017.

Risks Relating to Our Ongoing Relationship with Our General Partner and its Affiliates

Our general partner, through its subsidiary, owns our own common and preferred limited partner units representing an approximate 23.3% limited partner ownership interest. Therefore, our general partner possesses significant influence on all matters submitted to a vote of our unitholders.

At December 31, 2015, a wholly-owned subsidiary of Atlas Energy Group owned approximately 20.96 million common and 3.75 million preferred limited partner units, representing an approximate 23.3% limited partner ownership interest in us. Accordingly, our general partner possesses significant influence over matters submitted to our unitholders for approval, and could exercise such influence in a manner that is not in the best interests of our other unitholders, including the ability to effectively prevent the approval of certain matters, such as removal of our general partner and other extraordinary transactions for which super-majority approval is required under applicable Delaware law. In addition, our general partner is able to control, subject to our partnership agreement and applicable law, all matters affecting us, including:

- any determination with respect to our business direction and policies, including the appointment and removal of officers;
- any determinations with respect to mergers, business combinations or disposition of assets;
- our financing, including determinations as to the issuance of additional common or preferred units, and the terms thereof;
- compensation and benefit programs and other human resources policy decisions;
- the payment of distributions on our units; and
- determinations with respect to our tax returns.

Our general partner has the authority to conduct our business and manage our operations. Atlas Energy Group may have conflicts of interest, which may permit it to favor its own interests to our unitholders' detriment.

Conflicts of interest may arise between our general partner and its affiliates, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner is permitted to favor its own interests and the interests of its owners over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our general partner or any of its affiliates to pursue a business strategy that favors us or to refer any business opportunity to us;
- our general partner is expressly allowed to take into account the interests of parties other than us in resolving conflicts of interest;
- our partnership agreement eliminates any fiduciary duties owed by our general partner to us, and restricts the remedies available to unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;

- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of our drilling programs and related capital expenditures, asset purchases and sales, borrowings, issuance of additional partnership securities and reserves;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner determines the amount and timing of any capital expenditure and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion or investment capital expenditure, which does not reduce operating surplus. Our partnership agreement does not set a limit on the amount of maintenance capital expenditures that our general partner may estimate;

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner decides which costs incurred by it and its affiliates are reimbursable by us; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our general partner and affiliates of our general partner may compete with us. This could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our ability to replace reserves, results of operations and cash available for distribution to our unitholders.

Our partnership agreement provides that for so long as it is the general partner of ARP, our general partner's sole business will be to act as a general partner of ARP and any other partnership or limited liability company of which ARP is, directly or indirectly, a partner or member and to undertake activities that are ancillary or related thereto. This restriction does not apply to any person other than our general partner, and our general partner may hold or dispose any interest that it acquires or obtains from any affiliate or unrestricted person (as defined in our partnership agreement), and perform activities in connection holding such interest. Affiliates of our general partner, therefore, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Our general partner owns general and limited partner interests in AGP, an exploration and production development subsidiary, which currently conducts operations in the mid-continent region of the United States as well as interests in entities which incubate new master limited partnerships and invest in existing ones. Our general partner and its affiliates may make future investments and acquisitions that may include entities or assets that we would have been interested in acquiring. In addition, members of management of Atlas Energy Group have substantial experience in the natural gas and oil business.

Therefore, our general partner and its affiliates may compete with us for investment opportunities and our general partner and its affiliates may own an interest in entities that compete with us.

Our partnership agreement provides that:

- affiliates of our general partner have no obligation to refrain from engaging in the same or similar business activities or lines of business we do, doing business with any of our customers or employing or otherwise engaging any of our officers or employees;
- neither our general partner nor any of its officers or directors will be liable to us or to our unitholders for breach of any duty, including any fiduciary duty, by reason of any of these activities; and
- none of our general partner, its affiliates or any of their respective directors or officers is under any duty to present any corporate opportunity to us which may be a corporate opportunity for such person and us, and such person will not be liable to us or our unitholders for breach of any duty, including any fiduciary duty, by reason of the fact that such person pursues or acquires that corporate opportunity for itself, directs that corporate opportunity to another person or does not present that corporate opportunity to us.

Accordingly, our general partner and its affiliates may acquire, develop or dispose of additional natural gas or oil properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. These factors may make it difficult for us to compete with our general partner and its affiliates with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and accordingly cash available for distribution. This also may create actual and potential conflicts of interest between us and our general partner, and its affiliates and result in less than favorable treatment of us.

Certain of our officers and the directors of our general partner may have actual or potential conflicts of interest with us.

Our officers and our general partner’s directors have duties to manage us in a manner beneficial to us, but they also have duties to manage our general partner’s business in a manner beneficial to it. Certain of our non-independent directors and officers also have positions with other affiliates of our general partner. Consequently, these directors and officers may encounter situations in which their obligations to our general partner or one or more of its subsidiaries, on the one hand, and us, on the other hand, are in conflict. Additionally, such directors and officers may own common units of our general partner, options to purchase common units of our general partner or other equity awards, as well as equity of our general partner’s affiliates, which may be significant for some of these persons. Their positions and ownership of such equity and equity awards creates, or may create the appearance of, conflicts of interest when they are faced with decisions that could have different implications for Atlas Energy Group and/or its affiliates than the decisions have for us.

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 as of December 31, 2015. 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. A summary of the reserves report related to our estimated proved reserves at December 31, 2015 is 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 month during the years ended December 31, 2015 and 2014, and are listed below as of the dates indicated:

	December 31,	
	2015	2014
Unadjusted Prices[1]		
Natural gas (per Mcf)	$2.59	$4.35
Oil (per Bbl)	$50.28	$94.99
Natural gas liquids (per Bbl)	$11.02	$30.21
Average Realized Prices, Before Hedge[1] [2]		
Natural gas (per Mcf)	$2.23	$3.93
Oil (per Bbl)	$44.19	$82.22
Natural gas liquids (per Bbl)	$12.77	$29.39

(1) “Mcf” represents thousand cubic feet; and “Bbl” represents barrels.
(2) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for years ended December 31, 2015 and 2014. Including the effect of this subordination, the average realized sales price was $2.19 per Mcf before the effects of financial hedging and $3.84 per Mcf before the effects of financial hedging for years ended December 31, 2015 and 2014, 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 reserves engineer's evaluation was based on more than 39 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 reserves engineer's evaluation was based on more than 33 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 Senior Reserve Engineer, who is a member of the Society of Petroleum Engineers and has more than 17 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:

	Proved Reserves at December 31, 2015	2014
Proved reserves:		
Natural gas reserves (MMcf)[(1)]:		
Proved developed reserves	567,992	887,819
Proved undeveloped reserves[(2)]	36,586	168,566
Total proved reserves of natural gas	604,578	1,056,385
Oil reserves (MBbl)[(1)]:		
Proved developed reserves	25,484	30,538
Proved undeveloped reserves[(2)]	19,320	17,480
Total proved reserves of oil	44,804	48,018
NGL reserves (MBbl):		
Proved developed reserves	6,334	12,005
Proved undeveloped reserves[(2)]	1,516	9,752
Total proved reserves of NGL	7,850	21,757
Total proved reserves (MMcfe)[(1)]	920,504	1,475,035
Standardized measure of discounted future cash flows (in thousands)[(3)]	$502,769	$1,984,271

(1) "MMcf" represents million cubic feet; "MMcfe" represents million cubic feet equivalents; and "MBbl" represents thousand barrels. 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.

(2) 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 30%, which effectively will reduce our ownership interest in these reserves from 100% to our respective ownership interest as we make these contributions.

(3) Standardized measure 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 SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest and income tax expenses, or to depletion, depreciation and amortization. The future cash flows are discounted

using an annual discount rate of 10%. Standardized measure does not give effect to commodity derivative contracts. Because we are a limited partnership, no provision for federal or state income taxes has been included in the December 31, 2015 and 2014 calculations of standardized measure, which is, therefore, the same as the PV-10 value. Standardized measure for the years ended December 31, 2015 and 2014 includes approximately $(23.5) million and $(36.7) million related to the present value of future cash flows plugging and abandonment of wells, including the estimated salvage value. These amounts were not included in the summary reserve report that appear in Exhibits 99.2 and 99.3 in this report.

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, 2015, we had 102 PUD locations totaling approximately 162 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.

Changes in PUDs. Changes in PUDS that occurred during the year ended December 31, 2015 were due to the following:

- addition of approximately 76 Bcfe due to our drilling and leasing activity as well as locations purchased in the Eagle Ford Shale offset by
- negative revisions of approximately 219 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 $28.0 million, $164.9 million and $103.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. During the years ended December 31, 2015, 2014 and 2013, approximately 21 Bcfe, 41.2 Bcfe and 58.4 Bcfe of our reserves, respectively, were converted from PUDs to proved developed reserves. See “Item 1: Business - Overview” for further information. As of December 31, 2015, there were no PUDs that had remained undeveloped for five years or more. The proved undeveloped reserves disclosed as of December 31, 2015 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, 2015. 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	7,581	3,790
Oil wells	456	344
Total	8,037	4,134
Coal-bed Methane(3):		
Gas wells	3,646	2,896
Oil wells	—	—
Total	3,646	2,896
Barnett/Marble Falls:		
Gas wells	643	511
Oil wells	60	38
Total	703	549
Mississippi Lime/Hunton:		
Gas wells	106	60
Oil wells	—	—
Total	106	60
Rangely/Eagle Ford:		
Gas wells	—	—
Oil wells	427	125
Total	427	125
Other operating areas(4):		
Gas wells	759	237
Oil wells	2	1
Total	761	238

Total:		
Gas wells	12,735	7,494
Oil wells	945	508
Total	13,680	8,002

(1) Includes our proportionate interest in wells owned by 60 Drilling Partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 778 wells.
(2) There were no exploratory wells drilled during the years ended December 31, 2015, 2014 and 2013; there were no gross or net dry wells within our operating areas during the year ended December 31, 2015, 2014 and 2013.
(3) Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the Central Appalachian Basin in Virginia and West Virginia.
(4) Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

Developed and Undeveloped Acreage

The following table sets forth information about our developed and undeveloped natural gas and oil acreage as of December 31, 2015. 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	82,552	7,019	3,447
Pennsylvania	153,396	76,178	2,272	2,240
New Mexico	126,246	126,246	447,713	447,713
Ohio(5)	109,703	101,692	99,379	97,000
Texas	78,469	66,909	47,641	33,396
Alabama	57,600	56,494	3,973	2,383
Colorado	39,778	30,483	20,485	20,485
Indiana	32,835	27,275	38,228	32,537
Wyoming(6)	—	—	—	—
Oklahoma	125,929	95,029	77,798	37,413
Tennessee	20,119	8,409	42,496	42,296
New York	13,244	12,113	20,919	18,898
Virginia	5,240	4,004	2,237	2,086
Other	2,145	983	3,268	3,050
Total	913,493	688,367	813,428	742,944

(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 1,394 net acres under new leases taken in Ohio that remain undeveloped.
(6) County Line acreage sold to Carbon Creek Energy in October 2015.

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, 2015. As of December 31, 2015, leases covering approximately 4,702 of our 742,944 net undeveloped acres, or 0.6%, are scheduled to expire on or before December 31, 2016. An additional 1.6% and 0.2% are scheduled to expire in each of the years 2017 and 2018, respectively.

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 UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are listed on the New York Stock Exchange ("NYSE") and are traded under the ticker symbol "ARP". At the close of business on February 29, 2016, the closing price of our common limited partner units was $0.67, and there were 173 holders of record of our common limited partner units. The following table sets forth the high and low sales price per unit of our common limited partner units as reported by the NYSE and the cash distributions declared by quarter per unit on our common limited partner units for the years ended December 31, 2015 and 2014:

	High	Low	Cash Distribution per Common Limited Partner Declared(1)
Year ended December 31, 2015:			
Fourth quarter	$3.33	$0.65	$ 0.0375
Third quarter	$6.31	$2.23	$ 0.3249
Second quarter	$9.35	$6.19	$ 0.3249
First quarter	$11.49	$7.04	$ 0.3249
Year ended December 31, 2014:			
Fourth quarter	$19.60	$8.42	$ 0.5898
Third quarter	$20.94	$18.74	$ 0.5898
Second quarter	$21.45	$19.00	$ 0.5832
First quarter	$23.18	$20.19	$ 0.5799

(1) The determination of the amount of future cash distributions declared, if any, is at the sole discretion of our General Partner's board of directors and will depend on various factors affecting our financial conditions and other matters the board of directors deems relevant.

In January 2014, our board of directors approved the modification of our cash distribution payment practice to a monthly cash distribution program whereby we would distribute all of our available cash (as defined in the partnership agreement) for that month to our common and preferred unitholders and general partner within 45 days from the month end. Prior to that, we paid quarterly cash distributions within 45 days from the end of each calendar quarter. See "Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations—Cash Distribution Policy".

For information concerning common units authorized for issuance under our long-term incentive plan, see "Item 12: Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters – Equity Compensation Plan Information".

ITEM 6: SELECTED FINANCIAL DATA

The following table presents selected historical consolidated financial data for us and our predecessor, Atlas Energy E&P Operations, as of and for the periods indicated. Atlas Energy E&P Operations consists of the subsidiaries of Atlas Energy that held its natural gas and oil development and production assets and liabilities and its partnership management business, substantially all of which Atlas Energy, L.P. ("Atlas Energy") transferred to us on March 5, 2012. The consolidated statements of operations data for the years ended December 31, 2015, 2014 and 2013, and the consolidated balance sheet data as of December 31, 2015 and 2014, have been derived from our audited consolidated financial statements included in “Item 8: Financial Statements and Supplementary Data”. The consolidated statements of operations data for the year ended December 31, 2012 and the consolidated balance sheet data as of December 31, 2013 and 2012 has been derived from our audited consolidated financial statements that are not included in this Form 10-K. The consolidated statements of operations data for the year ended December 31, 2011 and the consolidated balance sheet data as of December 31, 2011 is derived from Atlas Energy E&P Operations’ audited consolidated financial statements that are not included in this Form 10-K.

On February 17, 2011, Atlas Energy acquired certain natural gas and oil properties, the partnership management business, and other assets (the “Transferred Business”) from Atlas Energy, Inc. (“AEI”), the former owner of Atlas Energy’s general partner. Management of Atlas Energy determined that the acquisition of the Transferred Business constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable assets and liabilities of the Transferred Business based upon their fair values with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit)/equity on our consolidated balance sheet. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the Transferred Business would have been included in our consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, we reflected the impact of the acquisition of the Transferred Business on our consolidated financial statements in the following manner:

- Recognized the assets acquired and liabilities assumed from the Transferred Business at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit) /equity;
- Retrospectively adjusted our consolidated financial statements for any date prior to February 17, 2011, the date of acquisition, to reflect our results on a consolidated basis with the results of the Transferred Business as of or at the beginning of the respective period; and
- Adjusted the presentation of our consolidated statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners and the general partner. The Transferred Business' historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by AEI to the underlying business segments, including the Transferred Business. We have reviewed AEI's general and administrative expense allocation methodology, which is based on the relative total assets of AEI and the Transferred Business, for the Transferred Business' historical financial statements prior to the date of acquisition and believe the methodology is reasonable and reflects the approximate general and administrative costs of our underlying business segments.

The following table should be read in conjunction with our and our predecessor's consolidated financial statements and accompanying notes included within "Item 8: Financial Statements and Supplementary Data" and "Item 7: Management's Discussion and Analysis of Financial Condition and Results of Operations". Our and our predecessor's consolidated financial information may not be indicative of our future performance and does not necessarily reflect what our financial position and results of operations would have been had Atlas Energy E&P Operations' operated as an independent, publicly traded company during the historical periods presented, including changes that would have occurred in our operations and capitalization as a result of the separation from Atlas Energy.

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per unit data)				
Statement of operations data:					
Revenues:					
Gas and oil production	$356,999	$470,051	$273,604	$92,901	$66,979
Well construction and completion	76,505	173,564	167,883	131,496	135,283
Gathering and processing	7,431	14,107	15,676	16,267	17,746
Administration and oversight	7,812	15,564	12,277	11,810	7,741
Well services	23,822	24,959	19,492	20,041	19,803
Gain on mark-to-market derivatives	267,223	2,819	—	—	—
Other, net	241	590	(14,456)	(4,886)	(30)
Total revenues	740,033	701,654	474,476	267,629	247,522
Costs and expenses:					
Gas and oil production	169,653	182,226	100,098	26,624	17,100
Well construction and completion	66,526	150,925	145,985	114,079	115,630
Gathering and processing	9,613	15,525	18,012	19,491	20,842
Well services	9,162	10,007	9,515	9,280	8,738
General and administrative	65,968	72,349	78,063	69,123	27,536
Chevron transaction expense	—	—	—	7,670	—
Depreciation, depletion and amortization	157,978	239,923	139,783	52,582	30,869
Asset impairment	966,635	573,774	38,014	9,507	6,995
Total costs and expenses	1,445,535	1,244,729	529,470	308,356	227,710
Operating income (loss)	(705,502)	(543,075)	(54,994)	(40,727)	19,812
Interest expense	(102,133)	(62,144)	(34,324)	(4,195)	—
Gain (loss) on asset sales and disposal	(1,181)	(1,869)	(987)	(6,980)	87
Net income (loss)	(808,816)	(607,088)	(90,305)	(51,902)	19,899
Preferred limited partner dividends	(16,469)	(19,267)	(11,992)	(3,063)	—
	$(825,285)	$(626,355)	$(102,297)	$(54,965)	$19,899

Net income (loss) attributable to owner's interest, common limited partners and the general partner					
Balance sheet data (at period end):					
Property, plant and equipment, net	$1,191,611	$2,263,820	$2,182,770	$1,302,228	$520,883
Total assets	1,731,004	2,798,120	2,408,358	1,498,952	702,366
Total debt, including current portion	1,534,482	1,394,460	942,334	351,425	—
Total partners' capital (deficit) / equity	(84,628)	947,537	1,133,733	862,006	457,175
Cash flow data:					
Net cash provided by operating activities	$172,804	$202,823	$123,932	$16,486	$71,437
Net cash used in investing activities	(204,002)	(896,443)	(1,049,606)	(644,278)	(47,509)
Net cash provided by financing activities	17,304	707,039	904,314	596,272	30,780
Capital expenditures	(127,138)	(212,728)	(263,886)	(127,226)	(47,324)
Operating data[(1)]					
Net production:					
Natural gas (Mcfd)	216,613	238,054	163,971	69,408	31,403
Oil (Bpd)	5,139	3,436	1,329	330	307

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	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per unit data)				
Natural gas liquids (Bpd)	3,155	3,802	3,473	974	444
Total (Mcfed)	266,374	281,486	192,786	77,232	35,912
Average sales price:					
Natural gas (per Mcf)(2):					
Realized price, after hedge(2)(3)	$3.41	$3.76	$3.48	$3.29	$4.98
Realized price, before hedge(2)	$2.23	$3.93	$3.25	$2.60	$4.53
Oil (per Bbl):					
Realized price, after hedge(3)	$84.30	$87.76	$91.01	$94.02	$89.70
Realized price, before hedge	$44.19	$82.22	$95.88	$91.32	$89.07
Natural gas liquids (per Bbl):					
Realized price, after hedge(3)	$22.40	$29.59	$28.71	$31.97	$48.26
Realized price, before hedge	$12.77	$29.39	$29.43	$31.97	$48.26
Production costs (per Mcfe):					
Lease operating expenses(4):	$1.34	$1.27	$1.08	$0.82	$1.09
Production taxes	0.19	0.27	0.18	0.12	0.10
Transportation and compression	0.24	0.25	0.25	0.24	0.43
Total	$1.76	$1.80	$1.50	$1.19	$1.61

(1) "Mcf" represents thousand cubic feet; "Mcfe" represents thousand cubic feet equivalents; "Mcfd" represents thousand cubic feet per day; "Mcfed" represents thousand cubic feet equivalents per day; and "Bbls" and "Bpd" represent barrels and barrels per day.

(2) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effect of this subordination, the average realized gas sales price $3.36 per Mcf ($2.19 per Mcf before the effects of financial hedging), $3.67 per Mcf ($3.84 per Mcf before the effects of financial hedging), $3.23 per Mcf ($3.00 per Mcf before the effects of financial hedging), $2.76 per Mcf ($2.08 per Mcf before the effects of financial hedging) and $4.28 per Mcf ($3.83 per Mcf before the effects of financial hedging) for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively.

(3) Includes 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, consisting of $48.6 million associated with natural gas derivative contracts, $35.8 million associated with crude oil derivative contracts, and $8.3 million associated with natural gas liquids derivative contracts for the year ended December 31, 2015 (see "Item 8. Financial Statements – Note 8").

(4) 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. Including the effects of these costs, total lease operating expenses per Mcfe were $1.32 per Mcfe ($1.74 per Mcfe for total production costs), $1.25 per Mcfe ($1.77 per Mcfe for total production costs), $1.00 per Mcfe ($1.42 per Mcfe for total production costs), $0.58 per Mcfe ($0.94 per Mcfe for total production costs) and $0.77 per Mcfe ($1.33 per Mcfe for total production costs) for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively.

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.

Unless the context otherwise requires, references below to "Atlas Resource Partners, L.P.," "Atlas Resource Partners," "the Partnership," "we," "us," "our" and "our company", when used for periods prior to March 5, 2012, refer to the subsidiaries and operations that Atlas Energy, L.P. contributed to Atlas Resource Partners in connection with the separation and, when used for periods after that date, refer to Atlas Resource Partners, L.P. and its consolidated subsidiaries. References below to "Atlas Energy" refer to Atlas Energy, L.P. and its consolidated subsidiaries for all periods through February 27, 2015 and Atlas Energy Group, LLC for all periods thereafter, unless the context otherwise requires.

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 or what they would have been had our predecessor been a separate, stand-alone company during the periods presented.

BUSINESS OVERVIEW

We are a publicly-traded (NYSE: ARP) Delaware master-limited partnership ("MLP") and an independent developer and producer of natural gas, crude oil and natural gas liquids ("NGL"), with operations in basins across the United States. We sponsor and manage tax-advantaged investment partnerships ("Drilling Partnerships"), in which we coinvest, to finance a portion of our natural gas, crude oil and natural gas liquid production activities.

On February 27, 2015, our general partner, Atlas Energy Group, LLC ("Atlas Energy Group"; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. ("Atlas Energy"), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as "ATLS"). Atlas Energy Group manages our operations and activities through its ownership of our general partner interest. Concurrent with Atlas Energy Group's unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. ("Targa"; NYSE: TRGP) (the "Atlas Merger") and ceased trading. At December 31, 2015, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

In addition to its general and limited partner interest in us, ATLS also holds general and limited partner interests in the following:

- 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
- Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

SUBSEQUENT EVENTS

Senior Note Repurchases. In January and February 2016, we executed transactions to repurchase portions of our senior unsecured notes. Through the end of February 2016, we have repurchased approximately $20.3 million of our 7.75% Senior Notes in 2021 and approximately $12.1 million of our 9.25% Senior Notes for approximately $5.5 million. As a result of these transactions, we will recognize approximately $25.9 million as gain on early extinguishment of debt in the first quarter of 2016.

Cash Distributions. On January 28, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of December 31, 2015. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner and preferred limited partners, respectively, was paid on February 12, 2016 to unitholders of record at the close of business on February 8, 2016.

On February 24, 2016, we declared a monthly distribution of $0.0125 per common unit for the month of January 31, 2016. The $2.0 million distribution, including $39,000 and $0.6 million to the general partner as holder of common units and Class C preferred limited units, respectively, will be paid on March 16, 2016 to unitholders of record at the close of business on March 9, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.5390625 per Class D Preferred Unit, or $2.2 million, for the period from October 15, 2015 through January 14, 2016 to Class D Preferred Unitholders of record as of January 4, 2016.

On January 15, 2016, we paid a quarterly distribution of $0.671875 per Class E Preferred Unit, or $0.2 million, for the period from October 15, 2015 through January 14, 2016 to Class E Preferred Unitholders of record as of January 4, 2016.

NYSE Compliance. On January 12, 2016, we were notified by the NYSE that we were not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of the common units had been less than $1.00 for 30 consecutive trading days. We are working to remedy this situation in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE.

RECENT DEVELOPMENTS

Credit Facility Amendment. On November 23, 2015, we entered into an Eighth Amendment to the Second Amended and Restated Credit Agreement (the "Amendment") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amendment amends the Second Amended and Restated Credit Agreement dated July 31, 2013 (as amended from time to time, the "Credit Agreement"). Among other things, the Eighth Amendment:

- reduced the borrowing base under the Credit Agreement from $750.0 million to $700.0 million;
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