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Atlas Resource Partners, L.P.
Form 10-K
March 02, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2014

OR

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

For the transition period from _____ to _____

Commission file number: 001-35317

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 Pittsburgh, PA (Address of principal executive offices)	15275 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 Common Units representing Limited Partnership Interests	Name of each exchange on which registered New York Stock Exchange
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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 No

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

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Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer 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 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 No

The aggregate market value of the voting and non-voting equity securities held by non-affiliates of the registrant, based on the closing price of the registrant's common units on the last business day of the registrant's most recently completed second quarter, June 30, 2014, was approximately \$1,210.6 million.

The number of outstanding common limited partner units of the registrant on February 25, 2015 was 85,382,998.

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 stock tank barrel or 42 United States gallons liquid volume.

Bcf. One billion cubic feet.

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. 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. Acres spaced or assigned to productive wells.

Development well. A well drilled within a 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. An exploratory, development or extension well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil and 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. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well as those items are defined in this section.

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.

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 oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

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

Mcfd. One thousand cubic feet per day.

Mcfed. One Mcfe per day.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

MMcfd. 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.

NGL. Natural gas liquids, which are the hydrocarbon liquids contained within gas.

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.

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 of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for undeveloped reserves cannot be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

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

Reserves. Reserves are estimated remaining quantities of oil and 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 gas or related substances to market, and all permits and financing required to implement the project.

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

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. Lease acreage on which wells have not been drilled and where it is either probable or possible that the acreage contains reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

FORWARD-LOOKING STATEMENTS

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

- 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 common units;
- future financial and operating results;
- resource potential;
- effects of partial depletion or drainage by earlier offset drilling on our acreage;
- economic conditions and instability in the financial markets;
- 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;
- restrictive covenants in indebtedness that may adversely affect operational flexibility;
- effects of debt payment obligations on our distributable cash;
- potential changes in tax laws which may impair the ability to obtain capital funds through investment partnerships;
- the ability to raise funds through investment partnerships or through access to the capital markets;

- 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;
- 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, 2014, our estimated proved reserves were 1,429 Bcfe, including the reserves net to our equity interest in our Drilling Partnerships. Of our estimated proved reserves, approximately 77% were proved developed and approximately 71% were natural gas. For the year ended December 31, 2014, our average daily net production was approximately 270.0 MMcfe. Through December 31, 2014, 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 715 wells and 399 Bcfe of total proved reserves with average daily production of 79.9 MMcfe for the year ended December 31, 2014;
- 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 the County Line area of Wyoming where we have ownership interests in approximately 3,440 wells and 523 Bcfe of total proved reserves with average daily production of 120.8 MMcfe for the year ended December 31, 2014;
- the Appalachia Basin, including the Marcellus Shale and the Utica Shale where we have ownership interests in approximately 8,127 wells, including approximately 272 wells in the Marcellus Shale, and 144 Bcfe of total proved reserves with average daily production of 40.7 MMcfe for the year ended December 31, 2014;
- the Eagle Ford Shale in southern Texas where we have ownership interests in approximately 24 wells in the Eagle Ford Shale and 64 Bcfe of total proved reserves with average daily production of 2.1 Bcfe for the year ended December 31, 2014;

- the Rangely field in northwest Colorado where we have non-operated ownership interests in approximately 400 wells in the Rangely field and 176 Bcfe of total proved reserves with average daily production of 8.3 Bcfe for the year ended December 31, 2014;
- the Mississippi Lime and Hunton plays in northwestern Oklahoma where we own 109 Bcfe of total proved reserves with average daily production of 12.7 MMcfe for the year ended December 31, 2014; 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 15 Bcfe of total proved reserves with average daily production of 5.4 MMcfe for the year ended December 31, 2014.

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. Since we began operations in March 2012, we have acquired significant net proved reserves and production through the following transactions:

- Carrizo Barnett Shale Acquisition – On April 30, 2012, we acquired 277 Bcfe of proved reserves, including undeveloped drilling locations, in the core of the Barnett Shale from Carrizo Oil & Gas, Inc. (NASD: CRZO; “Carrizo”) for approximately \$187.0 million (the “Carrizo Acquisition”). The assets included 198 gross producing wells generating approximately 31 MMcfed of production at the date of acquisition on over 12,000 net acres, all of which are held by production.

- Titan Barnett Shale Acquisition – On July 26, 2012, we acquired Titan Operating, L.L.C. (“Titan”), which owned approximately 250 Bcfe of proved reserves and associated assets in the Barnett Shale on approximately 16,000 net acres, which are 90% held by production, for approximately \$208.6 million (the “Titan Acquisition”). Net production from these assets at the date of acquisition was approximately 24 MMcfed, including approximately 370 Bpd of natural gas liquids. We believe there are over 300 potential undeveloped drilling locations on the Titan acreage.
- Equal Mississippi Lime Acquisition – On April 4, 2012, we entered into an agreement with Equal Energy, Ltd. (NYSE: EQU; TSX: EQU; “Equal”) to acquire a 50% interest in Equal’s approximately 14,500 net undeveloped acres in the core of the oil and liquids rich Mississippi Lime play in northwestern Oklahoma for approximately \$18.0 million. On September 24, 2012, we acquired Equal’s remaining 50% interest in approximately 8,500 net undeveloped acres included in the joint venture, approximately 8 MMcfed of net production in the region at the date of acquisition and substantial salt water disposal infrastructure for \$41.3 million (the “Equal Acquisition”). The transaction increased our position in the Mississippi Lime play to 19,800 net acres in Alfalfa, Grant and Garfield counties in Oklahoma.
- DTE Fort Worth Basin Acquisition – On December 20, 2012, we acquired 210 Bcfe of proved reserves in the Fort Worth basin from DTE Energy Company (NYSE: DTE; “DTE”) for \$257.4 million (the “DTE Acquisition”). The assets included 261 gross producing wells generating approximately 23 MMcfed of production at the date of acquisition on over 88,000 net acres, approximately 40% of which are held by production and approximately 33% are in continuous development. The acreage position includes approximately 75,000 net acres prospective for the oil and NGL-rich Marble Falls play, in which there are over 600 identified vertical drilling locations and further potential development opportunities through vertical down-spacing and horizontal drilling. The assets acquired from DTE are in close proximity to our other assets in the Barnett Shale.
- 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. We believe there are approximately 1,200 potential undeveloped drilling locations on the acreage acquired.
- 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 \$409.4 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, the Development Subsidiary of our general partner, 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 \$339.2 million, of which \$179.5 million was paid at closing by us and \$19.7 million was paid by the Development Subsidiary, and approximately \$140.0 million will be paid over the four quarters following closing. We will pay approximately \$24.0 million of the deferred portion of the purchase price in three quarterly installments beginning March 31, 2015. The Development Subsidiary will pay approximately \$116.0 million of the deferred portion purchase price in four quarterly installments following closing. We may pay up to \$20.0 million of our deferred portion of the purchase price with the issuance of our Class D Cumulative Redeemable Perpetual Preferred Units at a price of \$25.00 per unit ("Class D Preferred Units"). The acquisition has an effective date of July 1, 2014.

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At December 31, 2014, through the closing of the transaction described below, our general partner, Atlas Energy Group, LLC ("Atlas Energy Group"), a wholly-owned subsidiary of Atlas Energy, L.P. ("Atlas Energy"), a publicly traded master-limited partnership (NYSE: ATLS), managed our operations and activities through its ownership of our general partner interest (collectively, "ATLS"). On February 27, 2015, Atlas Energy was acquired by Targa Resources Corp. (NYSE: TRGP) ("TRC") through the merger of a subsidiary of TRC with and into Atlas Energy (the "Atlas Energy Merger"). Immediately prior to the closing of the Atlas Energy Merger, Atlas Energy transferred its assets and liabilities, other than those related to its midstream segment, to Atlas Energy Group and distributed, to the Atlas Energy unitholders of record as of February 25, 2015, approximately 26.0 million common units representing limited liability company interests in Atlas Energy Group. On March 2, 2015, Atlas Energy Group began trading on the NYSE under the symbol "ATLS."

At December 31, 2014, ATLS owned 100% of our general partner Class A units, all of the incentive distribution rights, and an approximate 27.7% 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").

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 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 12% of our segment margin for the year ended December 31, 2014. Additionally, our natural gas, crude oil and NGL production was hedged approximately 75% on an equivalent basis for the year ended December 31, 2014. As of December 31, 2014, we had approximately 203.7 Bcfe, 4.2 Mmbbl and 0.6 Mmbbl of hedge positions, respectively, on our natural gas, crude oil and NGL production for 2014 through 2018.

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:

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. In the first half of 2014, we acquired certain coal-bed methane producing natural gas assets in West Virginia and Virginia and low-decline oil and NGL assets in the Rangely field in northwest Colorado. In November 2014, we and ATLS's Development Subsidiary acquired interests in oil and natural gas assets in the Eagle Ford Shale in South Central Atascosa County, Texas.

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, 2014, we raised over \$0.7 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.

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, 2014.

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.

Subsequent Events

Credit Facility Amendment. On February 23, 2015, we entered into a Sixth Amendment to the Second Amended and Restated Credit Agreement (the “Sixth 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 (the “Credit Agreement”), dated July 31, 2013. Among other things, the Sixth Amendment:

- reduces the borrowing base under the Credit Agreement from \$900.0 million to \$750.0 million;
- permits the incurrence of second lien debt in an aggregate principal amount up to \$300.0 million;
- 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

·revises 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 ended 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 ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarters ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

The Amendment was approved by the lenders and was effective on February 23, 2015.

Second Lien Term Loan Facility. On February 23, 2015, we entered into a Second Lien Credit Agreement (the “Second Lien Credit Agreement”) with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto. 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.

We have the option to prepay the Term Loan Facility at any time, and are required to offer to prepay the Term Loan Facility with 100% of the net cash proceeds from the issuance or incurrence of any debt and 100% of the excess net cash proceeds from certain asset sales and condemnation recoveries. We are also required to offer to prepay the Term Loan Facility upon the occurrence of a change of control. All prepayments are subject to the following premiums, plus accrued and unpaid interest:

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;
- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

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 (the “Loan Parties”) 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 applicable maturity date for Eurodollar loans and quarterly for ABR loans.

The Second Lien Credit Agreement contains customary covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in our existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables.

Under the Second Lien Credit Agreement, we may elect to add one or more incremental term loan tranches to the Term Loan Facility so long as the aggregate outstanding principal amount of the Term Loan Facility plus the principal amount of any incremental term loan does not exceed \$300.0 million and certain other conditions are adhered to. Any such incremental term loans may not mature on a date earlier than February 23, 2020.

Recent Developments

Eagle Ford Shale Asset Acquisition. On November 5, 2014, we and ATLS's Development Subsidiary completed an acquisition of oil and natural gas liquid assets in the Eagle Ford Shale in Atascosa County, Texas. The purchase price was \$339.2 million, of which \$179.5 million was paid at closing by us and \$19.7 million was paid by the Development Subsidiary, and approximately \$140.0 million will be paid over the four quarters following closing. We will pay approximately \$24.0 million of the deferred portion of the purchase price in three quarterly installments beginning March 31, 2015. The Development Subsidiary will pay approximately \$116.0 million of the deferred portion purchase price in four quarterly installments following closing. We may pay up to \$20.0 million of our deferred portion of the purchase price with the issuance of our Class D Preferred Units. The acquisition has an effective date of July 1, 2014.

Issuance of Senior Notes. In connection with the Eagle Ford Acquisition, in October 2014, we issued an additional \$75.0 million of our 9.25% Senior Notes due 2021 ("9.25% Senior Notes") in a private transaction under Rule 144A and Regulation S of the Securities Act of 1933, as amended (the "Securities Act") at an offering price of 100.5%. In connection with the issuance, we also entered into a registration rights agreement. Under the registration rights agreement, we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated no later than 270 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we agreed to file a shelf registration statement with respect to the issuance. If we fail to comply with the obligations to register the notes within the specified time periods, we will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration is declared effective, as applicable.

Issuance of Preferred Units. Also in connection with the Eagle Ford Acquisition, in October 2014 we issued 3.2 million 8.625% Class D Preferred Units at a public offering price of \$25.00 per Class D Unit. On January 15, 2015, we paid an initial quarterly distribution of \$0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015. We will pay future cumulative distributions on a quarterly basis, at an annual rate of \$2.15625 per unit, or 8.625% of the liquidation preference.

Equity Distribution Program. On August 29, 2014, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to \$100.0 million. Sales of common units, if any, may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the

terms of a separate terms agreement between us and such Agent. As of December 31, 2014, no units have been sold under this program.

Rangely Acquisition. On June 30, 2014, we completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado for approximately \$409.4 million in cash, net of purchase price adjustments. The purchase price was funded through borrowings under our revolving credit facility, the issuance of an additional \$100.0 million of our 7.75% Senior Notes due 2021 (“7.75% Senior Notes”) and the issuance of 15,525,000 common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of \$19.90 per unit. The Rangely Acquisition had an effective date of April 1, 2014.

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 assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

Issuance of Common Units. In March 2014, we issued 6,325,000 of our common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of \$21.18 per unit.

Cash Distribution Practice. In January 2014, our board of directors approved the modification of our cash distribution payment practice to a monthly cash distribution program whereby a monthly cash distribution is paid within 45 days from the month end.

Geographic and Geologic Overview

Through December 31, 2014, 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 400 feet. As of December 31, 2014, we had an interest in approximately 715 Barnett Shale and Marble Falls wells. As of December 31, 2014, we had more than 115,000 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 15 to 400 feet. As of December 31, 2014, we had an interest in approximately 272 Marcellus Shale wells, consisting of 229 vertical wells and 43 horizontal wells. As of December 31, 2014, 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, 2014, approximately 2,327 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, 2014, we had drilled, completed and placed into production eight horizontal Utica-Point Pleasant wells, and spud four additional wells that were in the process of drilling. As of December 31, 2014, we had approximately 10,608 net undeveloped acres prospective for the Utica Shale in Trumbull and Stark counties in Ohio. We also currently have an interest in approximately 2,100 wells in Ohio and operate four field offices which we intend to use for future Utica Shale development.

Coal-Bed Methane. Our coal-bed methane developments are diversified across three well-known coal-bed methane producing areas: the Raton, Black Warrior and Central Appalachian basins. As of December 31, 2014, we had more than 480,000 net undeveloped acres prospective for coal-bed methane. Also as of December 31, 2014, we operated 2,246 wells and had an interest in another 1,194 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, 2014, we operated 972 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, 2014, we operated 862 wells and had an interest in an additional 715 wells at the Black Warrior 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 central and northern West Virginia. As of December 31, 2014, we operated 412 wells and had an interest in an additional 60 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 700 feet, and the net production interval within the formation varies from approximately 50 to 400 feet.

Eagle Ford. The Eagle Ford Shale is an Upper Cretaceous-age formation that is prospective for horizontal drilling in approximately 20 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. In November 2014, we acquired 22 producing wells and 19 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, 2014, we had an interest in approximately 35 Hunton wells. As of December 31, 2014, we had drilled 49 Mississippi Lime horizontal wells, of which 46 were completed and producing. As of December 31, 2014, had have identified an additional 136 horizontal Mississippi Lime locations across our over 29,000 net acre leaseholds.

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 coinvestment 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, 2014, 2013, and 2012:

Years Ended December 31,

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	2014	2013	2012
Production per day: ⁽¹⁾⁽²⁾			
Natural gas (Mcfed)	226,526	158,886	69,408
Oil (Bpd)	3,436	1,329	330
Natural gas liquids (Bpd)	3,802	3,473	974
Total (Mcfed)	269,958	187,701	77,232

(1) “Mcfed” represents thousand cubic feet per day; “Mcf” 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.

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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, 2014, 2013, and 2012, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Years Ended December 31,		
	2014	2013	2012
Production revenues (in thousands):			
Natural gas revenue	\$302,826	\$186,229	\$70,151
Oil revenue	110,070	44,160	11,351
Natural gas liquids revenue	41,061	36,394	11,399
Total revenues	\$453,957	\$266,783	\$92,901
Average sales price: ⁽¹⁾			
Natural gas (per Mcf):			
Total realized price, after hedge ⁽²⁾	\$3.76	\$3.47	\$3.29
Total realized price, before hedge ⁽²⁾	\$3.93	\$3.25	\$2.60
Oil (per Bbl):			
Total realized price, after hedge	\$87.76	\$91.01	\$94.02
Total realized price, before hedge	\$82.22	\$95.88	\$91.32
NGLs (per Bbl):			
Total realized price, after hedge	\$29.59	\$28.71	\$31.97
Total realized price, before hedge	\$29.39	\$29.43	\$31.97
Production costs (per Mcfe): ⁽¹⁾			
Lease operating expenses ⁽³⁾	\$1.29	\$1.09	\$0.82
Production taxes	0.27	0.18	0.12
Transportation and compression	0.25	0.24	0.24
Total	\$1.81	\$1.50	\$1.19

(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 \$3.66 per Mcf (\$3.84 per Mcf before the effects of financial hedging), \$3.21 per Mcf (\$2.99 per Mcf before the effects of financial hedging), and \$2.76 per Mcf (\$2.08 per Mcf before the effects of financial hedging) for the years ended December 31, 2014, 2013, and 2012, respectively.

(3)

Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effects of these costs, total lease operating expenses per Mcfe were \$1.27 per Mcfe (\$1.79 per Mcfe for total production costs), \$1.01 per Mcfe (\$1.42 per Mcfe for total production costs), and \$0.58 per Mcfe (\$0.94 per Mcfe for total production costs) for the years ended December 31, 2014, 2013, and 2012, 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 \$0.7 billion 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
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
2010 ⁽¹⁾	149.3	53.4	202.7
Total	\$ 735.1	\$ 299.4	\$1,034.5

(1) Does not include funds raised for a fall 2010 drilling program, which was cancelled due to the announcement of the acquisition of the Transferred Business in November 2010 (see “Item 7: Management’s Discussion and Analysis of Financial Condition and Results of Operations”).

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;

- 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; and

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 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 \$9,400 in the year in which the investor invests.

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

Drilling Activity

The number of wells we drill will vary depending on, among other things, the amount of money we raise through our Drilling Partnerships, the cost of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table sets forth information with respect to the number of wells we drilled, both gross and for our interest, during the periods indicated. There were no exploratory wells drilled during the years ended December 31, 2014, 2013, and 2012.

	Years Ended		
	December 31,		
	2014	2013	2012
Gross wells drilled	129	103	105
Our share of gross wells drilled ⁽¹⁾	67	66	42
Gross wells turned in line	119	117	154
Net wells turned in line	64	80	43

(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.

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

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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, 2014, we had the following ongoing drilling activities:

	Gross		Net		Completed
	Spud	Depth	Spud	Depth	
Mississippi Lime – Horizontal	7	2	3	1	1
Utica – Horizontal	4	—	2	—	—
Marble Falls – Vertical	—	9	—	3	1
Eagle Ford - Horizontal	—	2	—	2	—

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 15-20% range, resulting in net revenue interests to us in the 80-85% 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; 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, 2014, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC accounted for approximately 25%, 15%, 14% and 13% 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. During the years ended December 31, 2014 and 2013, we faced no shortage of these goods and services. Over the past several years, we and other oil and natural gas companies have experienced higher 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 maintain a Pennsylvania Operating Services Agreement, pursuant to which a subsidiary of Chevron Corporation provides us (including Drilling Partnerships which we manage) with water disposal services with respect to certain wells in Pennsylvania in exchange for specified fees. We will indemnify the provider against all claims and liabilities arising out of its provision of services under this agreement. We may terminate the agreement at any time, and either party may terminate the agreement following an uncured material breach of the agreement by the other party. The initial term of this agreement expired on February 17, 2014 and has continued through the end of 2014. On February 12, 2015, we received notice of termination from Chevron Corporation and as such, the Pennsylvania Operating Services Agreement will terminate on or about September 12, 2015. Subsequent to the termination of the Pennsylvania Operating Services Agreement, we will utilize other available vendors in the area.

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. During the years ended December 31, 2014, 2013, and 2012, we did not experience problems in selling our natural gas, oil and NGLs, although prices have varied significantly during those periods.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. In addition, seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in certain areas. These seasonal anomalies may pose challenges for meeting our well construction objectives and increase competition for equipment, supplies and personnel, which could lead to shortages and increase costs or delay our operations. We have in the past drilled a greater number of wells during the winter months because we typically received the majority of funds from Drilling Partnerships during the fourth calendar quarter.

Environmental Matters and Regulation

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

- restricting the way waste disposal is handled;
- limiting or prohibiting drilling, construction and operating activities in sensitive areas such as wetlands, coastal regions, non-attainment areas, tribal lands or areas inhabited by threatened or endangered species;
- requiring the acquisition of various permits before the commencement of drilling;

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

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

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

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

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

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 USEPA, 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 USEPA 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 USEPA 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 and USEPA proposed a rule that would define ‘Waters of the United States,’ 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 U.S. Army Corps of Engineers and USEPA have stated that the proposed rule would enhance protection for nationwide public health and aquatic resources, and increase Clean Water Act program predictability and consistency. The public comment period concluded on November 14, 2014. USEPA is in the process of reviewing the more than 800,000 comments received on the proposed rule, and has indicated that a final rule may be issued in 2015. As drafted, this proposed rule may increase the costs of compliance and result in additional permitting requirements for some of our existing or future facilities. Additionally, USEPA’s Science Advisory Board released its review of USEPA’s Office of Research and Development’s draft “Connectivity of Streams and Wetlands to Downstream Waters: A Review and Synthesis of the Scientific Evidence” report issued October 17, 2014. USEPA released the final report publicly on January 15, 2015.

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, obtain and comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Various air quality regulations are periodically reviewed by USEPA and are amended as deemed necessary. USEPA may also issue new regulations based on changing environmental concerns.

Recent revisions to federal NSPS and NESHAP 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, USEPA 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.

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, USEPA 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), USEPA made a final determination that greenhouse gases endangered public health and welfare, 74 Fed. Reg. 66,496 (December 15, 2009). This finding led to the regulation of greenhouse gases under the Clean Air Act. Currently, USEPA has promulgated two rules that will affect our businesses.

First, USEPA 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 "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.

Second, USEPA finalized its Mandatory Reporting of Greenhouse Gases rule in 2009, 74 Fed. Reg. 56,260 (October 30, 2009). Subsequent revisions, additions and clarification rules were promulgated, including a rule specifically addressing the natural gas industry. This subpart was most recently revised in November 2014, when USEPA finalized changes to calculation methods, monitoring and data reporting requirements, and other provisions. Shortly thereafter, in December 2014, USEPA proposed additional revisions to this subpart 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 USEPA 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 is 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. Among other steps being

taken as part of this national methane strategy, USEPA is expected to build on the 2012 NSPS in a rulemaking action aimed at reducing both methane and VOC emissions from the oil and gas sector.

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 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, USEPA published a draft “Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels” on May 10, 2012. In February 2014, USEPA released its revised final guidance document on SDWA underground injection control permitting for hydraulic fracturing using diesel fuels, along with responses to selected substantive public comments on USEPA’s previous draft guidance, a fact sheet and a memorandum to USEPA’s regional offices regarding implementation of the guidance. The process for implementing USEPA’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. If re-introduced in the current 114th Session of Congress and 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 its operations to ensure the safety of its 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 2014, the impact fee for qualifying unconventional horizontal wells spudded during 2014 was \$50,300 per well, while the impact fee for unconventional vertical wells was \$10,100 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 and \$.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 \$0.095 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 USEPA and the Department of Interior, are currently evaluating a variety of environmental issues related to hydraulic fracturing. For example, USEPA is conducting a study that evaluates any potential effects of hydraulic fracturing on drinking water and ground water. USEPA released a progress report on this study on December 21, 2012 that did not provide any results or conclusions. On December 9, 2013, USEPA’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 USEPA’s study were published in July 2014. Research results are expected to be released in draft form for review by the public and USEPA Science Advisory Board. USEPA has not provided a specific date for completion of the draft report after peer review, which may occur in 2015. The Department of Interior’s Bureau of Land Management published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands on May 24, 2013. The comment period closed on August 23, 2013 and the revised proposed rule drew more than 175,000 comments. A revised rule was reportedly sent to the White House Office of Management and Budget review in August 2014, and a final rule is expected to be issued in 2015.

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, 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. 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, 2014, approximately 670 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”. You may also receive, without charge, a paper copy of any such filings by request to us at Park Place Corporate Center One, 1000 Commerce Drive, Suite 400, Pittsburgh, Pennsylvania 15275, telephone number (800) 251-0171. A complete list of our filings is available on the SEC’s website at www.sec.gov. Any of our filings are also available at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The Public Reference Room may be contacted at telephone number (800) 732-0330 for further information.

ITEM 1A: RISK FACTORS

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. 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, 2014, the NYMEX Henry Hub natural gas index price ranged from a high of \$6.15 per MMBtu to a low of \$2.89 per MMBtu, and West Texas Intermediate oil prices ranged from a high of \$107.26 per Bbl to a low of \$53.27 per Bbl. Between January 1, 2015 and February 25, 2015, the NYMEX Henry Hub natural gas index price ranged from a high of \$3.23 per MMBtu to a low of \$2.58 per MMBtu, and West Texas Intermediate oil prices ranged from a high of \$53.53 per Bbl to a low of \$44.45 per Bbl. If natural gas and oil prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

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.

Shortages of drilling rigs, equipment and crews, or the costs required to obtain the foregoing in a highly competitive environment, could impair our operations and results.

Increased demand for drilling rigs, equipment and crews, due to increased activity by participants in our primary operating areas or otherwise, can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues.

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 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.

The natural gas and oil industry is capital intensive. If we are unable to obtain sufficient capital funds on satisfactory terms with capital raised through equity and debt offerings, cash flow from operations, bank borrowings and the Drilling Partnerships, 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.

Our cash distribution policy limits our ability to grow.

Because we distribute our available cash 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; or

- an increase in working capital requirements.

If we issue additional common units or incur debt to fund acquisitions and expansion and 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 increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units.

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, 2014, Tenaska Marketing Ventures, Chevron, Enterprise and Interconn Resources LLC accounted for approximately 25%, 15%, 14% and 13% 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, 2014, leases covering approximately 40,103 of our 794,030 net undeveloped acres, or 5.1%, are scheduled to expire on or before December 31, 2015. An additional 0.7% of our net undeveloped acres are scheduled to expire in 2016 and 1.6% in 2017. 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. 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;
- environmental accidents such as gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment or oil leaks, 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, 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.

Although we maintain insurance against various losses and liabilities arising from our operations, insurance against all operational risks are 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.

A 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. Accordingly, further declines in the price of commodities 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.

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 generally limit these arrangements to smaller quantities than those we project to be available at any delivery point.

In addition, we may enter into financial hedges, which may include purchases of regulated NYMEX futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties in compliance with the Dodd-Frank Wall Street Reform and Consumer Protection Act. The 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 Dodd-Frank Act is intended to change fundamentally the way swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which most swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. These statutory requirements are implemented through regulation, primarily through rules adopted by the Commodity Futures Trading Commission. Many market participants are newly regulated as swap dealers or major swap participants, with new regulatory capital requirements and other regulations that impose business conduct rules and mandate how they hold collateral or margin for swap transactions. All market participants are subject to new reporting and recordkeeping requirements. The new regulations may require us to comply with certain clearing and trade-execution requirements in connection with our existing or future derivative activities. As a commercial end-user which uses swaps to hedge or mitigate commercial risk, rather than for speculative purposes, we are permitted to opt out of the clearing and exchange trading requirements, but we could nevertheless be exposed to greater liquidity and credit risk with respect to our hedging transactions if we do not use cleared and exchange-traded swaps.

The 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. 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.

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

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

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

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. Based upon the Department of Health report, New York State Department of Environmental Conservation Commissioner Joe Martens announced that it will soon issue a legally-binding findings statement that will prohibit hydraulic fracturing in the state. Martens noted that the public health risks associated with hydraulic fracturing outweigh its potential economic benefits, particularly in light of the number of municipalities that have banned natural gas drilling within their borders.

· 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. According to PADEP, the conceptual changes would update existing requirements regarding containment of regulated substances, waste disposal, site restoration and reporting releases, and would establish new planning, notice, construction, operation, reporting and monitoring standards for surface activities associated with the development of oil and gas wells. PADEP has also proposed to add new requirements for addressing impacts to public resources, identifying and monitoring orphaned and abandoned wells during hydraulic fracturing activities, and submitting water withdrawal information necessary to secure a required water management plan. The public comment period on the proposed amendments to PADEP's proposed amendments at 25 Pa. Code Chapter 78, Subchapter C closed on March 14, 2014, and PADEP is in the process of reviewing and considering over 24,000 comments received during the comment period. 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). PADEP has indicated that it will bifurcate its 25 Pa. Code Chapter 78 regulations into two parts as a result of a legislative bill that passed in July 2014

as a companion to Pennsylvania's budget for 2014 to 2015. 25 Pa. Code Chapter 78 will apply to conventional wells and 25 Pa. Code Chapter 78A will apply to unconventional wells. 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 February 2014, the regulatory authority proposed 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.

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·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 new 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 1984 Oil and Gas Act. While the total impact of these rulings 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. 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. 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, EPA issued draft permitting guidance for oil and gas hydraulic fracturing activities using diesel fuel. In February 2014, 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 EPA's previous draft guidance, a fact sheet and a memorandum to EPA's regional offices regarding implementation of the guidance. The process for implementing 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, EPA is currently studying the potential environmental effects of hydraulic fracturing on drinking water and groundwater. EPA issued a progress report regarding the hydraulic fracturing study on December 21, 2012. However, the progress report did not provide any results or conclusions. On December 9, 2013, 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 EPA's study were published in July 2014. Research results are expected to be

released in draft form for review by the public and EPA's Science Advisory Board. EPA has not provided a specific date for completion of the draft report after peer review, which may occur in 2015. In 2013, 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, EPA has yet to propose the draft water quality criteria document and it has not provided an updated timeframe for the proposal. EPA announced in its September 2014 "Final 2012 and Preliminary 2014 Effluent Guidelines Program Plans" document that it intends to continue a rulemaking effort to potentially revise the effluent limitation guidelines for the Oil and Gas Extraction Point Source Category to address pretreatment standards for shale gas extraction. EPA proposed in that same document a detailed study of centralized waste treatment facilities that accept oil and gas extraction wastewater. The public comment period on the Preliminary 2014 Effluent Guidelines Program Plan closed on November 17, 2014. EPA is evaluating the comments submitted and will next prepare and issue the Final 2014 Effluent Guidelines Program Plan. On May 4, 2012, the U.S. Department of the Interior, Bureau of Land Management proposed a rule that includes provisions requiring disclosure of chemicals used in hydraulic fracturing and construction standards for hydraulic fracturing on federal lands. On May 24, 2013, the Bureau of Land Management published a revised proposed rule to regulate hydraulic fracturing on federal and Indian lands. The comment period closed on August 23, 2013 and the revised proposed rule drew more than 175,000 comments. A revised rule was reportedly sent to the White House Office of Management and Budget review in August 2014, and a final rule is expected to be issued in 2015.

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. The next Annual Energy Outlook is reported to be in March 2015 by U.S. Energy Information Administration. 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 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, or 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 will 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. As part of the Climate Action Plan, the Obama Administration also announced that it intends to adopt additional regulations to reduce emissions of greenhouse gases and to encourage greater use of low carbon technologies in the coming years. 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.

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

In August 2012, EPA published final rules that established new and revised requirements for emissions from oil and natural gas production and natural gas processing operations. Specifically, EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants to address emissions of hazardous air pollutants frequently associated with oil and natural gas production, processing, transmission and storage activities. The New Source Performance Standards require operators, beginning January 1, 2015, to reduce volatile organic compounds emissions from oil and natural gas production facilities by conducting "green completions" for hydraulic fracturing, that is, recovering rather than venting or flaring the gas and NGLs that come to the surface during completion of the fracturing process. The New Source Performance Standards also established new notification and reporting requirements, more stringent leak detection standards for natural gas processing plants, and specific requirements regarding emissions from compressors, storage tanks, and other sources. In 2013, EPA made significant changes to the New Source Performance Standards applicable to storage vessels, and in December 2014, EPA finalized additional revisions to the New Source Performance Standards, including revisions to the green completion requirements. Compliance with recently revised New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

States are also proposing more stringent requirements for emissions from well sites and compressor stations. For example, in August 2013, Pennsylvania revised its list of sources exempt from air permitting requirements such that previously exempted types of sources associated with unconventional oil and gas exploration and production now are required to demonstrate compliance with specific criteria (e.g., emission limits, monitoring and recordkeeping) in order to claim the permit exemption. PADEP has since released implementation instructions that expand the list of information which operators must submit in a compliance demonstration in order to rely on the exemption. Additionally, PADEP issued a revised General Permit for Natural Gas Compression and/or Processing Facilities in January 2015 that requires the permittee to annually certify its compliance with the terms and conditions of the general permit. In April 2014, Ohio revised its current General Permit for Natural Gas Production Operations to cover emissions from completion activities. In 2013, West Virginia issued General Permit 70-A for natural gas production facilities at the well site. In February 2015, West Virginia issued a draft General Permit 80-A to replace General Permit 70-A and other existing general permits for natural gas compressor and dehydration facilities.

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, the 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 water will affect our production, and potential increases in the cost of water 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 produced water, 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 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. Pennsylvania's Oil and Gas Act of 2012, passed in February 2012, implemented an impact fee for unconventional wells drilled in the Commonwealth. An unconventional gas well is a well that is drilled into an unconventional formation, which would include the Marcellus Shale. The impact fee, which changes from year to year, is computed using the prior year's trailing 12-month NYMEX natural gas price and is based upon a tiered pricing matrix. Based upon natural gas prices for 2014, the impact fee for qualifying unconventional horizontal wells spudded during 2014 was \$50,300 per well and the impact fee for unconventional vertical wells was \$10,100 per well. The impact fee is due by April 1 of the year following the year that a horizontal unconventional well is spudded or a vertical unconventional well is put into production. The fee will continue for 15 years for a horizontal unconventional well and 10 years for a vertical unconventional well. ARP estimates that the impact fee for its wells including the wells in its Drilling Partnerships will be approximately \$1.0 million for the year ended December 31, 2014. If new laws implementing additional taxes and fees become applicable, our operating costs may materially increase.

President Obama's budget proposals for fiscal year 2016 includes proposed provisions with significant tax consequences. The proposed budget, if enacted, would repeal over \$4 billion per year in U.S. tax subsidies to oil, gas and other fossil fuel producers.

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 oil and gas enforcement activities. For

example, in 2011, 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 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, the 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. Proposed regulations associated with this legislation were published for public comment by the PADEP and, if finalized, will affect how natural gas operations are conducted in Pennsylvania. 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 \$166.8 million, \$150.0 million, and \$127.1 million in 2014, 2013, and 2012, 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 2016 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, 2014, \$5.3 million of our revenues, net of corresponding production costs, were subordinated, which reduced our cash distributions received from the Drilling Partnerships. For the years ended December 31, 2013 and 2012, the subordinated amounts were \$9.6 million and \$6.3 million, respectively, net of corresponding production costs.

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.

Covenants in our credit facility restrict our business in many ways.

Our credit facility contains 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 credit facility requires 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. A breach of any of these covenants could result in a default under our credit facility. Upon the occurrence of an event of default, the lenders under the credit facility could elect to declare all amounts outstanding immediately due and payable and 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 facility. If the lenders accelerate the repayment of borrowings, we may not have sufficient assets to repay our credit facility and our other liabilities. Our borrowings under our credit facility 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 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. In addition, our actual cash requirements in the future may be greater than expected. Our cash flow may not be sufficient to repay all of the outstanding debt as it becomes due, and we may not be able to borrow money, sell assets or otherwise raise funds on acceptable terms, or at all, to refinance our debt.

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.

Our operations are affected by the financial markets and related effects in the global financial system. The consequences of an economic recession and the effects of the financial crisis include a lower level of economic activity and increased volatility in energy prices. This may result in a decline in energy consumption and lower market prices for oil and natural gas and has previously resulted in a reduction in drilling activity in our service areas. Any of these events may adversely affect our revenues and ability to fund capital expenditures and, in the future, may impact the cash that we have available to fund our operations, pay required debt service on our credit facility and make distributions to our unitholders.

Potential instability in the financial markets, as a result of recession or otherwise, can cause volatility in the markets and may 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 or to respond to competitive pressures, any of which could negatively impact our business.

A 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 affects 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 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 Common Units

If the unit price declines, our common unitholders could lose a significant part of their investment.

The market price of our common 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 units.

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

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

At December 31, 2014, Atlas Energy owned approximately 20.96 million common and 3.75 million preferred limited partner units, representing approximately 27.7% limited partner ownership interest in us, all of which were distributed to a subsidiary of our general partner in the Atlas Energy Merger. 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.

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

Like all equity investments, an investment in our common 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 common units resulting from investors seeking other investment opportunities may cause the trading price of our common 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 future operations, future capital expenditures, 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 depends primarily on our cash flow and not solely on profitability.

The amount of cash that we have available for distribution 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 credit facility have restrictions and financial covenants that may restrict our business and financing activities and 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 revolving credit facility restricts, among other things, our ability to incur debt and pay distributions, and requires us to comply with customary financial covenants and specified financial ratios. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our revolving credit facility that are not cured or waived within the specified time periods, a significant portion of our indebtedness may become immediately due and payable, and we will be prohibited from making distributions to our unitholders. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our revolving credit facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our revolving credit facility, the lenders could seek to foreclose on our assets.

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 common units in any fiscal quarter, our unitholders are not entitled to receive distributions for such prior periods in the future.

Our distributions to our unitholders are not cumulative. Consequently, if we do not pay distributions on our common units with respect to any quarter, our unitholders are not entitled to such payments in the future.

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 common 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 common units of any holder that is not an eligible citizen or fails to furnish the requested information.

Common 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 common 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.

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, without unitholder approval, which would dilute common 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 units that we may issue at any time without the approval of our common 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. The issuance by us of additional units or other equity interests of equal or senior rank will have the following effects:

- our common 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 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 New York Stock Exchange (“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 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 common units, 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 the common units 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 common units at an undesirable time or price. You may also incur a tax liability upon a sale of your common 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.

Your 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. You could be liable for any and all of our obligations as if you 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
- your 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.

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.

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 may be required to pay taxes on income from us even if you do not receive any cash distributions from us.

Unitholders will be required to pay U.S. federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, whether or not you receive cash distributions from us. 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.

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, West Virginia and Wyoming. 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.

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

Affiliates of our general partner own common and preferred limited partner units representing an approximate 27.7% limited partner ownership interest. Therefore, our general partner possesses significant influence on all matters submitted to a vote of our unitholders.

At December 31, 2014, Atlas Energy owned approximately 20.96 million common and 3.75 million preferred limited partner units, representing an approximate 27.7% limited partner ownership interest in us, all of which were distributed to an affiliate of our general partner in the Atlas Energy Merger. 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;
- compensation and benefit programs and other human resources policy decisions;

- the payment of dividends 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. ATLS 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 an exploration and production development subsidiary, which currently conducts operations in the mid-continent region of the United States, interests in entities which incubate new master limited partnerships and invest in existing ones, and natural gas development and production assets in the Arkoma Basin. 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 ATLS 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 ATLS 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 the officers and directors of our general partner may have actual or potential conflicts of interest with us.

Our general partner's officers and 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 ATLS 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, 2014. 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 reserve report related to our estimated proved reserves at December 31, 2014 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, 2014 and 2013, and are listed below as of the dates indicated:

	December 31,	
	2014	2013
Unadjusted Prices ⁽¹⁾		
Natural gas (per Mcf)	\$4.35	\$3.67
Oil (per Bbl)	\$94.99	\$96.78
Natural gas liquids (per Bbl)	\$30.21	\$30.10
Average Realized Prices, Before Hedge ^{(1) (2)}		
Natural gas (per Mcf)	\$3.93	\$3.25
Oil (per Bbl)	\$82.22	\$95.88
Natural gas liquids (per Bbl)	\$29.39	\$29.43

(1) "Mcf" represents thousand cubic feet; and "Bbl" represents barrels.

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(2) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for years ended December 31, 2014 and 2013. Including the effect of this subordination, the average realized sales price was \$3.84 per Mcf before the effects of financial hedging and \$2.99 per Mcf before the effects of financial hedging for years ended December 31, 2014 and 2013, 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. Other than for our Rangely assets, for the periods presented, 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 38 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 32 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 16 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 the Chief Operating Officer and 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,	
	2014	2013
Proved reserves:		
Natural gas reserves (MMcf) ⁽¹⁾ :		
Proved developed reserves	841,805	727,931
Proved undeveloped reserves ⁽²⁾	168,566	236,907
Total proved reserves of natural gas	1,010,371	964,838
Oil reserves (MBbl) ⁽¹⁾ :		
Proved developed reserves	30,536	3,459
Proved undeveloped reserves ⁽²⁾	17,480	11,530
Total proved reserves of oil	48,016	14,989
NGL reserves (MBbl):		
Proved developed reserves	12,005	7,676
Proved undeveloped reserves ⁽²⁾	9,752	11,281
Total proved reserves of NGL	21,757	18,957
Total proved reserves (MMcfe) ⁽¹⁾	1,429,015	1,168,514
Standardized measure of discounted future cash flows (in thousands) ⁽³⁾	\$1,885,208	\$1,039,192

- (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 (“Mcf”) 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, 2014 and 2013 calculations of standardized measure, which is, therefore, the same as the PV-10 value. Standardized measure for the years ended December 31, 2014 and 2013 includes approximately (\$36.7) million and \$2.0 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, 2014, we had 426 PUD locations totaling approximately 331.9 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.

Historically, the primary focus of our drilling operations has been in the Appalachian Basin. Subsequent to our acquisitions in the Barnett Shale and Marble Falls play, the Mississippi Lime play, the Raton Basin, Black Warrior Basin and the County Line area of Wyoming during the years ended December 31, 2013 and 2012, we will continue to integrate these areas and increase our proved reserves through organic leasing as well as drilling on our existing undeveloped acreage.

Our organic growth will focus on expanding our acreage position in our target areas, including our operations in the Marcellus Shale, Utica Shale, Barnett Shale, Marble Falls play, the Mississippi Lime play, the Raton Basin, the Black Warrior Basin and the County Line area of Wyoming. Through our previous drilling in these regions, as well as our geologic analyses of these areas, we are expecting these expansion locations to have a significant impact on our proved reserves.

Changes in PUDs. Changes in PUDS that occurred during the year ended December 31, 2014 were due to the following:

- addition of approximately 50.5 Bcfe due to our drilling activity in the Marcellus Shale, Utica Shale, Mississippi Lime and Marble Falls play;
- addition of approximately 29.2 Bcfe due to our acquisition of acreage in the Raton and Black Warrior Basins;
- addition of approximately 31.8 Bcfe due to our acquisition of acreage in the Eagle Ford Shale; partially offset by
- negative revisions of approximately 147.2 Bcfe in PUDs primarily due to the reduction of our five year drilling plans in the Barnett Shale and pricing scenario revisions.

Development Costs. Costs incurred related to the development of PUDs were approximately \$164.8 million, \$103.3 million, and \$79.4 million for the years ended December 31, 2014, 2013, and 2012, respectively. During the years ended December 31, 2014, 2013, and 2012, approximately 41.2 Bcfe, 58.4 Bcfe, and 30.6 Bcfe of our reserves, respectively, were converted from PUDs to proved developed reserves. Of the 30.6 Bcfe of our reserves converted from PUDs to proved developed reserves during the year ended December 31, 2012, 29.8 Bcfe is related to PUDs acquired and developed during the year. See “Item 1: Business - Overview” for further information. As of December 31, 2014, there were no PUDs that had remained undeveloped for five years or more.

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, 2014. 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	7,634	3,751
Oil wells	493	354
Total	8,127	4,105
Coal-bed Methane ⁽³⁾ :		
Gas wells	3,440	2,584
Oil wells	—	—
Total	3,440	2,584
Barnett/Marble Falls:		
Gas wells	565	469
Oil wells	150	99
Total	715	568
Mississippi Lime/Hunton:		
Gas wells	99	61
Oil wells	—	—
Total	99	61
Rangely/Eagle Ford:		
Gas wells	—	—
Oil wells	424	123
Total	424	123
Other operating areas ⁽⁴⁾ :		
Gas wells	763	237
Oil wells	2	1
Total	765	238

Total:		
Gas wells	12,501	7,102
Oil wells	1,069	577
Total	13,570	7,679

- (1) Includes our proportionate interest in wells owned by 67 Drilling Partnerships for which we serve as managing general partner and various joint ventures. This does not include royalty or overriding interests in 646 wells.
- (2) There were no exploratory wells drilled during the years ended December 31, 2014, 2013, and 2012; there were no gross or net dry wells within our operating areas during the year ended December 31, 2014 and 2013. During the year ended December 31, 2012, there were 8 gross (3 net) dry wells drilled in the Niobrara Shale.
- (3) Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the County Line area of Wyoming, 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, 2014. 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	387,478	157,699	3,946	2,047
Pennsylvania	154,445	74,819	2,358	2,327
New Mexico	126,246	126,246	447,713	447,713
Ohio ⁽⁵⁾	109,736	101,345	100,431	98,154
Texas	83,384	72,085	65,572	53,224
Alabama	56,200	55,218	40,488	37,104
Colorado	39,778	31,663	20,924	20,924
Indiana	32,388	24,781	61,949	54,648
Wyoming	29,737	5,677	830	156
Oklahoma	22,253	18,266	13,170	11,060
Tennessee	20,119	8,409	45,108	44,908
New York	13,254	12,122	20,957	18,936
Virginia	6,489	6,040	—	—
Other	1,290	207	3,014	2,829
Total	1,082,797	694,577	826,460	794,030

(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 10,608 net acres under new leases taken in Ohio that remain undeveloped.

The leases for our developed acreage generally have terms that extend for the life of the wells, while the leases on our undeveloped acreage have terms that vary from less than one year to five years. There are no concessions for undeveloped acreage as of December 31, 2014. As of December 31, 2014, leases covering approximately 40,103 of our 794,030 net undeveloped acres, or 5.1%, are scheduled to expire on or before December 31, 2015. An additional 0.7% and 1.6% are scheduled to expire in each of the years 2016 and 2017, 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 12”.

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 25, 2015, the closing price of our common limited partner units was \$10.04, and there were 183 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, 2014 and 2013:

	High	Low	Cash Distribution per Common Limited Partner Declared ⁽¹⁾
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
Year ended December 31, 2013:			
Fourth quarter	\$21.65	\$18.78	\$ 0.5800
Third quarter	\$22.77	\$18.30	\$ 0.5600
Second quarter	\$25.71	\$20.68	\$ 0.5400
First quarter	\$25.10	\$21.82	\$ 0.5100

(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, 2014, 2013, and 2012 and the consolidated balance sheet data as of December 31, 2014 and 2013, have been derived from our audited consolidated financial statements included in “Item 8: Financial Statements and Supplementary Data”. The consolidated balance sheet data for the year ended December 31, 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 years ended December 31, 2011 and 2010 and the consolidated balance sheet data as of December 31, 2011 and 2010 are 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/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/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,				
	2014	2013	2012	2011	2010
	(in thousands, except per unit data)				
Statement of operations data:					
Revenues:					
Gas and oil production	\$453,957	\$266,783	\$92,901	\$ 66,979	\$ 93,050
Well construction and completion	173,564	167,883	131,496	135,283	206,802
Gathering and processing	14,107	15,676	16,267	17,746	14,087
Administration and oversight	15,564	12,277	11,810	7,741	9,716
Well services	24,959	19,492	20,041	19,803	20,994
Other, net	3,409	(14,456)	(4,886)	(30)	—
Total revenues	685,560	467,655	267,629	247,522	344,649
Costs and expenses:					
Gas and oil production	176,194	97,237	26,624	17,100	23,323
Well construction and completion	150,925	145,985	114,079	115,630	175,247
Gathering and processing	15,525	18,012	19,491	20,842	20,221
Well services	10,007	9,515	9,280	8,738	10,822
General and administrative	72,349	78,063	69,123	27,536	11,381
Chevron transaction expense	—	—	7,670	—	—
Depreciation, depletion and amortization	233,731	136,763	52,582	30,869	40,758
Asset impairment	573,774	38,014	9,507	6,995	50,669
Total costs and expenses	1,232,505	523,589	308,356	227,710	332,421
Operating income (loss)	(546,945)	(55,934)	(40,727)	19,812	12,228
Interest expense	(62,144)	(34,324)	(4,195)	—	—
Gain (loss) on asset sales and disposal	(1,869)	(987)	(6,980)	87	(2,947)
Net income (loss)	(610,958)	(91,245)	(51,902)	19,899	9,281
Preferred limited partner dividends	(19,267)	(11,992)	(3,063)	—	—
Net income (loss) attributable to owner's interest, common limited partners and the general partner	\$(630,225)	\$(103,237)	\$(54,965)	\$ 19,899	\$ 9,281
Balance sheet data (at period end):					
Property, plant and equipment, net	\$2,208,171	\$2,120,818	\$1,302,228	\$ 520,883	\$ 508,484
Total assets	2,727,575	2,343,800	1,498,952	702,366	649,232
Total debt, including current portion	1,394,460	942,334	351,425	—	—
Total equity	885,496	1,067,291	862,006	457,175	381,882

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Cash flow data:

Net cash provided by operating activities	\$190,423	\$122,900	\$16,486	\$71,437	\$60,586
Net cash used in investing activities	(896,394)	(984,554)	(644,278)	(47,509)	(92,423)
Net cash provided by financing activities	719,390	840,294	596,272	30,780	31,837
Capital Expenditures	(212,634)	(263,537)	(127,226)	(47,324)	(93,608)

Operating data⁽¹⁾

Net production:

Natural gas (Mcfed)	226,526	158,886	69,408	31,403	35,855
Oil (Bpd)	3,436	1,329	330	307	373
Natural gas liquids (Bpd)	3,802	3,473	974	444	499
Total (Mcfed)	269,958	187,701	77,232	35,912	41,090

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	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands, except per unit data)				
Average sales price:					
Natural gas (per Mcf) ⁽²⁾ :					
Realized price, after hedge ⁽²⁾	\$3.76	\$3.47	\$3.29	\$4.98	\$7.08
Realized price, before hedge ⁽²⁾	\$3.93	\$3.25	\$2.60	\$4.53	\$4.60
Oil (per Bbl):					
Realized price, after hedge	\$87.76	\$91.01	\$94.02	\$89.70	\$77.31
Realized price, before hedge	\$82.22	\$95.88	\$91.32	\$89.07	\$71.37
Natural gas liquids (per Bbl):					
Realized price, after hedge	\$29.59	\$28.71	\$31.97	\$48.26	\$37.78
Realized price, before hedge	\$29.39	\$29.43	\$31.97	\$48.26	\$37.78
Production costs (per Mcfe):					
Lease operating expenses ⁽³⁾ :	\$1.29	\$1.09	\$0.82	\$1.09	\$1.27
Production taxes	0.27	0.18	0.12	0.10	0.04
Transportation and compression	0.25	0.24	0.24	0.43	0.65
Total	\$1.81	\$1.50	\$1.19	\$1.61	\$1.96

- (1) “Mcf” represents thousand cubic feet; “Mcfe” represents thousand cubic feet equivalents; “Mcf/d” 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 was \$3.66 per Mcf (\$3.84 per Mcf before the effects of financial hedging), \$3.21 per Mcf (\$2.99 per Mcf before the effects of financial hedging), \$2.76 per Mcf (\$2.08 per Mcf before the effects of financial hedging), \$4.28 per Mcf (\$3.83 per Mcf before the effects of financial hedging), and \$5.78 per Mcf (\$3.30 per Mcf before the effects of financial hedging) for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively.
- (3) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships. Including the effects of these costs, total lease operating expenses per Mcfe were \$1.27 per Mcfe (\$1.79 per Mcfe for total production costs), \$1.01 per Mcfe (\$1.42 per Mcfe for total production costs), \$0.58 per Mcfe (\$0.94 per Mcfe for total production costs), \$0.77 per Mcfe (\$1.33 per Mcfe for total production costs), and \$0.86 per Mcfe (\$1.56 per Mcfe for total production costs) for the years ended December 31, 2014, 2013, 2012, 2011, and 2010, 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" or "ATLS" 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 (see "Subsequent Events").

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 Delaware 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 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.

At December 31, 2014, our general partner, Atlas Energy Group, LLC ("Atlas Energy Group"), a wholly owned subsidiary of Atlas Energy, L.P. ("Atlas Energy"), a publicly traded master-limited partnership (NYSE: ATLS), manages our operations and activities through its ownership of our general partner interest (collectively, "ATLS"). At December 31, 2014, ATLS 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 27.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

We were formed in October 2011 to own and operate substantially all of ATLS's exploration and production assets ("Atlas Energy E&P Operations"), which were transferred to us on March 5, 2012. In February 2012, the board of directors of ATLS's general partner approved the distribution of approximately 5.24 million of our common units which were distributed on March 13, 2012 to ATLS's unitholders using a ratio of 0.1021 of our limited partner units for each of ATLS's common units owned on the record date of February 28, 2012.

SUBSEQUENT EVENTS

Atlas Energy Merger. On February 27, 2015, Atlas Energy was acquired by Targa Resources Corp. (NYSE: TRGP) ("TRC") through the merger of a subsidiary of TRC with and into Atlas Energy (the "Atlas Energy Merger"). Immediately prior to the closing of the Atlas Energy Merger, Atlas Energy transferred its assets and liabilities, other than those related to its midstream segment, to Atlas Energy Group and distributed, to the Atlas Energy unitholders of record as of February 25, 2015, approximately 26.0 million common units representing limited liability company interests in Atlas Energy Group. On March 2, 2015, Atlas Energy Group began trading on the NYSE under the symbol "ATLS".

At December 31, 2014, ATLS owned 100% of our general partner Class A units, all of the incentive distribution rights, and an approximate 27.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

Credit Facility Amendment. On February 23, 2015, we entered into a Sixth Amendment to the Second Amended and Restated Credit Agreement (the “Sixth 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 (the “Credit Agreement”), dated July 31, 2013. Among other things, the Sixth Amendment:

- reduces the borrowing base under the Credit Agreement from \$900.0 million to \$750.0 million;
- permits the incurrence of second lien debt in an aggregate principal amount up to \$300.0 million;
- 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
- revises 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 ended 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 ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarters ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

The Amendment was approved by the lenders and was effective on February 23, 2015.

Second Lien Term Loan Facility. On February 23, 2015, we entered into a Second Lien Credit Agreement (the “Second Lien Credit Agreement”) with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto. 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.

We have the option to prepay the Term Loan Facility at any time, and are required to offer to prepay the Term Loan Facility with 100% of the net cash proceeds from the issuance or incurrence of any debt and 100% of the excess net cash proceeds from certain asset sales and condemnation recoveries. We are also required to offer to prepay the Term Loan Facility upon the occurrence of a change of control. All prepayments are subject to the following premiums, plus accrued and unpaid interest:

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;
- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

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 (the “Loan Parties”) 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 applicable maturity date for Eurodollar loans and quarterly for ABR loans.

The Second Lien Credit Agreement contains customary covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in our existing first lien revolving credit facility, including,

among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables.

Under the Second Lien Credit Agreement, we may elect to add one or more incremental term loan tranches to the Term Loan Facility so long as the aggregate outstanding principal amount of the Term Loan Facility plus the principal amount of any incremental term loan does not exceed \$300.0 million and certain other conditions are adhered to. Any such incremental term loans may not mature on a date earlier than February 23, 2020.

Cash Distributions. On February 23, 2015, we declared a cash distribution of \$0.1083 per common unit for the month of January 2015. The \$9.9 million distribution, including \$0.2 million and \$0.4 million to the general partner and preferred limited partners, respectively, will be paid on March 17, 2015 to holders of record as of March 10, 2015.

On January 28, 2015, we declared a cash distribution of \$0.1966 per common unit for the month of December 2014. The \$18.9 million distribution, including \$1.4 million and \$0.7 million to the general partner and preferred limited partners, respectively, was paid on February 13, 2015 to holders of record as of February 9, 2015.

RECENT DEVELOPMENTS

Eagle Ford Shale Asset Acquisition. On November 5, 2014, we and ATLS's Development Subsidiary completed an acquisition of oil and natural gas liquid assets in the Eagle Ford Shale in Atascosa County, Texas. The purchase price was \$339.2 million, of which \$179.5 million was paid at closing by us and \$19.7 million was paid by the Development Subsidiary, and approximately \$140.0 million will be paid over the four quarters following closing. We will pay approximately \$24.0 million of the deferred portion of the purchase price in three quarterly installments beginning March 31, 2015. The Development Subsidiary will pay approximately \$116.0 million of the deferred portion purchase price in four quarterly installments following closing. We may pay up to \$20.0 million of our deferred portion of the purchase price with the issuance of our Class D Redeemable Perpetual Cumulative Preferred Units ("Class D Preferred Units"). The acquisition has an effective date of July 1, 2014.

Issuance of Senior Notes. In connection with the Eagle Ford Acquisition, in October 2014, we issued an additional \$75.0 million of our 9.25% Senior Notes due 2021 ("9.25% Senior Notes") in a private transaction under Rule 144A and Regulation S of the Securities Act of 1933, as amended (the "Securities Act") at an offering price of 100.5%. In connection with the issuance, we also entered into a registration rights agreement. Under the registration rights agreement, we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated no later than 270 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we agreed to file a shelf registration statement with respect to the issuance. If we fail to comply with our obligations to register the notes within the specified time periods, we will be subject to additional interest, up to 1%

per annum, until such time that the exchange offer is consummated or the shelf registration is declared effective, as applicable.

Issuance of Preferred Units. Also in connection with the Eagle Ford Acquisition, in October 2014 we issued 3,200,000 8.625% Class D Preferred Units at a public offering price of \$25.00 per Class D preferred unit. On January 15, 2015, we paid an initial quarterly distribution of \$0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015. We will pay future cumulative distributions on a quarterly basis, at an annual rate of \$2.15625 per unit, or 8.625% of the liquidation preference.

Equity Distribution Program. On August 29, 2014, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the “Agents”). Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to \$100.0 million. Sales of common units, if any, may be made in negotiated transactions or transactions that are deemed to be “at-the-market” offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent (see “Issuances of Units”). As of December 31, 2014, no units have been sold under this program.

Rangely Acquisition. On June 30, 2014, we completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado for approximately \$409.4 million in cash, net of purchase price adjustments. The purchase price was funded through borrowings under our revolving credit facility, the issuance of an additional \$100.0 million of our 7.75% Senior Notes due 2021 (“7.75% Senior Notes”) and the issuance of 15,525,000 common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of \$19.90 per unit. The Rangely Acquisition had an effective date of April 1, 2014.

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 assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

Issuance of Common Units. In March 2014, we issued 6,325,000 of our common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of \$21.18 per unit.

Cash Distribution Practice. In January 2014, our board of directors approved the modification of our cash distribution payment practice to a monthly cash distribution program whereby a monthly cash distribution is paid within 45 days from the month end.

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 our 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;
- Raton - ANR, Panhandle, and NGPL;
- Black Warrior Basin - Southern Natural;
- Eagle Ford – Transco Zone 1; 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.

We hold firm transportation obligations on Colorado Interstate Gas for the benefit of production from the Raton Basin in the New Mexico/Colorado Area. The total of firm transportation held is approximately 82,500 dth/d at a weighted average rate of \$0.2575/MMBtu under contracts expiring in 2016. We also hold firm transportation obligations on East Tennessee Natural Gas, Columbia Gas Transmission and Equitrans for the benefit of production from the central Appalachian Basin. The total of firm transportation held is approximately 25,000 dth/d, 15,500 dth/d and 2,300 dth/d, respectively, under contracts expiring between the years 2015 and 2022.

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 indicated above and our 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, 2014, Tenaska Marketing Ventures, Chevron, Enterprise, and Interconn Resources LLC accounted for approximately 25%, 15%, 14% and 13% 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. 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%.

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;
- 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; and

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%.

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.

GENERAL TRENDS AND OUTLOOK

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

The natural gas, oil and natural gas liquids commodity price markets have suffered significant declines during the fourth quarter of 2014 and early 2015, particularly in December 2014 and January 2015. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, our ability to make payments on our debt and our ability to make distributions to our unitholders, including ATLS, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas and oil production from particular wells decrease. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce.

RESULTS OF OPERATIONS

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various plays throughout the United States. We had certain agreements which restricted our ability to drill additional wells in certain areas of Pennsylvania, New York and West Virginia, including portions of the Marcellus Shale, which expired on February 17, 2014. Through December 31, 2014, we have established production positions in the following operating areas:

- the Appalachia Basin, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region;
- coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming, where we established a position following our acquisition of certain assets from EP Energy during 2013, which is also referred to as the “EP Energy Acquisition”, as well as the Central Appalachia Basin in West Virginia and Virginia, where we established a position following our acquisition of assets from GeoMet Inc. in May 2014, which is also referred to as the “GeoMet Acquisition” (see “Recent Developments”);
- the Barnett Shale and Marble Falls play, both in the Fort Worth Basin in northern Texas. The Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil. We established our position

following our acquisitions of assets from Carrizo Oil & Gas, Inc., Titan Operating, LLC and DTE Energy Company during 2012. We refer to these acquisitions as the “Carrizo”, “Titan” and “DTE” acquisitions;

- the Rangely field in northwest Colorado, a mature tertiary CO₂ flood with low-decline oil production, where we have a 25% non-operated net working interest position following our acquisition on June 30, 2014, which is referred to as the “Rangely Acquisition” (see “Recent Developments”);
- the Eagle Ford Shale in south Texas, in which we and ATLS’s Development Subsidiary acquired acreage and producing wells in November 2014;
- the Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area, in which we established a position following our acquisition from Equal in 2012; and
- our other operating areas, including the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; and the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled and the number of wells we turned in line, both gross and for our interest, during the years ended December 31, 2014, 2013, and 2012:

	Years Ended December 31,		
	2014	2013	2012
Gross wells drilled:			
Appalachia			
Marcellus Shale	—	—	10
Utica	4	3	5
Ohio	—	—	7
Barnett/Marble Falls	97	75	21
Eagle Ford	2	—	—
Mississippi Lime	26	25	11
Niobrara	—	—	51
Total	129	103	105
Net wells drilled ⁽¹⁾ :			
Appalachia			
Marcellus Shale	—	—	3
Utica	1	1	1
Ohio	—	—	2
Barnett/Marble Falls	51	55	18
Eagle Ford	1	—	—
Mississippi Lime	14	10	3
Niobrara	—	—	15
Total	67	66	42
Gross wells turned in line:			
Appalachia			
Marcellus Shale	—	9	31
Utica	3	5	—
Ohio	—	—	10
Barnett/Marble Falls	94	82	7
Mississippi Lime	22	21	3
Chattanooga	—	—	5
Niobrara	—	—	98

Total	119	117	154
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	Years Ended December 31,		
	2014	2013	2012
Net wells turned in line:			
Appalachia			
Marcellus Shale	—	3	9
Utica	1	2	—
Ohio	—	—	3
Barnett/Marble Falls	53	65	6
Mississippi Lime	10	10	1
Chattanooga	—	—	1
Niobrara	—	—	23
Total	64	80	43

(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 ownership in our Drilling Partnerships.

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Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes and production per day for the years ended December 31, 2014, 2013, and 2012:

	Years Ended December 31,		
	2014	2013	2012
Production: ⁽¹⁾⁽²⁾⁽³⁾			
Appalachia:			
Natural gas (MMcf)	13,928	13,397	12,403
Oil (000's Bbls)	139	121	102
Natural gas liquids (000's Bbls)	15	8	4
Total (MMcfe)	14,852	14,171	13,036
Coal-bed Methane:			
Natural gas (MMcf)	44,080	17,465	—
Oil (000's Bbls)	—	—	—
Natural gas liquids (000's Bbls)	—	—	—
Total (MMcfe)	44,080	17,465	—
Barnett/Marble Falls:			
Natural gas (MMcf)	20,937	23,744	10,561
Oil (000's Bbls)	389	295	10
Natural gas liquids (000's Bbls)	985	1,004	173
Total (MMcfe)	29,180	31,539	11,661
Rangely/Eagle Ford: ⁽⁴⁾			
Natural gas (MMcf)	64	—	—
Oil (000's Bbls)	561	—	—
Natural gas liquids (000's Bbls)	63	—	—
Total (MMcfe)	3,810	—	—
Mississippi Lime/Hunton:			
Natural gas (MMcf)	2,486	1,779	510
Oil (000's Bbls)	156	63	3
Natural gas liquids (000's Bbls)	205	118	30
Total (MMcfe)	4,648	2,859	705
Other operating areas:			
Natural gas (MMcf)	1,187	1,609	1,929
Oil (000's Bbls)	9	7	6
Natural gas liquids (000's Bbls)	121	138	150
Total (MMcfe)	1,965	2,477	2,865
Total production:			
Natural gas (MMcf)	82,682	57,993	25,403
Oil (000's Bbls)	1,254	485	121
Natural gas liquids (000's Bbls)	1,388	1,268	357
Total (MMcfe)	98,535	68,511	28,267
Production per day: ⁽¹⁾⁽²⁾⁽³⁾			
Appalachia:			
Natural gas (Mcf/d)	38,160	36,705	33,889
Oil (Bpd)	381	332	278
Natural gas liquids (Bpd)	41	22	10
Total (Mcfed)	40,689	38,825	35,618

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Coal-bed Methane:			
Natural gas (Mcfed)	120,768	47,848	—
Oil (Bpd)	—	—	—
Natural gas liquids (Bpd)	—	—	—
Total (Mcfed)	120,768	47,848	—
Barnett/Marble Falls:			
Natural gas (Mcfed)	57,361	65,053	28,855
Oil (Bpd)	1,066	808	28
Natural gas liquids (Bpd)	2,698	2,751	473
Total (Mcfed)	79,946	86,409	31,861

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	Years Ended December 31,		
	2014	2013	2012
Rangely/Eagle Ford: ⁽⁴⁾			
Natural gas (Mcfed)	175	—	—
Oil (Bpd)	1,538	—	—
Natural gas liquids (Bpd)	173	—	—
Total (Mcfed)	10,438	—	—
Mississippi Lime/Hunton:			
Natural gas (Mcfed)	6,810	4,873	1,392
Oil (Bpd)	427	171	8
Natural gas liquids (Bpd)	561	322	81
Total (Mcfed)	12,734	7,834	1,926
Other operating areas:			
Natural gas (Mcfed)	3,253	4,408	5,271
Oil (Bpd)	25	18	16
Natural gas liquids (Bpd)	330	378	410
Total (Mcfed)	5,384	6,786	7,827
Total production per day:			
Natural gas (Mcfed)	226,526	158,886	69,408
Oil (Bpd)	3,436	1,329	330
Natural gas liquids (Bpd)	3,802	3,473	974
Total (Mcfed)	269,958	187,701	77,232

- (1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling Partnership's proportionate net revenue interest in these wells.
- (2) "MMcf" represents million cubic feet; "MMcfe" represent million cubic feet equivalents; "Mcfed" represents thousand cubic feet per day; "Mcfed" represents thousand cubic feet equivalents per day; and "Bbls" and "Bpd" represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.
- (3) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the County Line area of Wyoming; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.
- (4) Rangely includes production from July 1, 2014, the date of the acquisition, through December 31, 2014; Eagle Ford includes production from November 5, 2014, the date of the acquisition, through December 31, 2014. Production per day represents production based on the full 365-day year ended December 31, 2014.

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the years ended December 31, 2014, 2013, and 2012, along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

	Years Ended December 31,		
	2014	2013	2012
Production revenues (in thousands): ⁽¹⁾			
Appalachia:			
Natural gas revenue	\$40,030	\$36,375	\$35,193
Oil revenue	11,785	10,564	9,678
Natural gas liquids revenue	599	223	223
Total revenues	\$52,414	\$47,162	\$45,094
Coal-bed Methane:			
Natural gas revenue	\$181,737	\$66,055	\$—
Oil revenue	—	—	—
Natural gas liquids revenue	—	—	—
Total revenues	\$181,737	\$66,055	\$—
Barnett/Marble Falls:			
Natural gas revenue	\$65,562	\$70,167	\$25,545
Oil revenue	35,772	26,578	887
Natural gas liquids revenue	26,344	26,929	4,959
Total revenues	\$127,678	\$123,674	\$31,391
Rangely/Eagle Ford:			
Natural gas revenue	\$183	\$—	\$—
Oil revenue	47,597	—	—
Natural gas liquids revenue	3,254	—	—
Total revenues	\$51,034	\$—	\$—
Mississippi Lime/Hunton:			
Natural gas revenue	\$10,134	\$7,010	\$1,840
Oil revenue	14,044	6,452	241
Natural gas liquids revenue	7,459	5,175	1,140
Total revenues	\$31,637	\$18,637	\$3,221
Other operating areas:			
Natural gas revenue	\$5,180	\$6,622	\$7,573
Oil revenue	872	566	545
Natural gas liquids revenue	3,405	4,067	5,077
Total revenues	\$9,457	\$11,255	\$13,195
Total production revenues:			
Natural gas revenue	\$302,826	\$186,229	\$70,151
Oil revenue	110,070	44,160	11,351
Natural gas liquids revenue	41,061	36,394	11,399
Total revenues	\$453,957	\$266,783	\$92,901
Average sales price:			
Natural gas (per Mcf): ⁽²⁾			
Total realized price, after hedge ⁽³⁾	\$3.76	\$3.47	\$3.29

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Total realized price, before hedge ⁽³⁾	\$3.93	\$3.25	\$2.60
Oil (per Bbl): ⁽²⁾			
Total realized price, after hedge	\$87.76	\$91.01	\$94.02
Total realized price, before hedge	\$82.22	\$95.88	\$91.32
Natural gas liquids (per Bbl): ⁽²⁾			
Total realized price, after hedge	\$29.59	\$28.71	\$31.97
Total realized price, before hedge	\$29.39	\$29.43	\$31.97

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	Years Ended December 31,		
	2014	2013	2012
Production costs (per Mcfe): ^{(1) (2)}			
Appalachia:			
Lease operating expenses ⁽⁴⁾	\$1.12	\$1.08	\$1.02
Production taxes	0.06	0.07	0.08
Transportation and compression	0.45	0.47	0.38
	\$1.64	\$1.62	\$1.48
Coal-bed Methane:			
Lease operating expenses	\$1.07	\$0.90	\$—
Production taxes	0.34	0.23	—
Transportation and compression	0.32	0.34	—
	\$1.73	\$1.48	\$—
Barnett/Marble Falls:			
Lease operating expenses	\$1.41	\$1.18	\$0.61
Production taxes	0.26	0.19	0.18
Transportation and compression	0.06	0.09	0.12
	\$1.73	\$1.46	\$0.90
Rangely/Eagle Ford:			
Lease operating expenses	\$3.63	\$—	\$—
Production taxes	0.64	—	—
Transportation and compression	0.01	—	—
	\$4.28	\$—	\$—
Mississippi Lime/Hunton:			
Lease operating expenses	\$1.46	\$1.47	\$1.38
Production taxes	0.14	0.20	0.29
Transportation and compression	0.27	0.15	—
	\$1.87	\$1.83	\$1.67
Other operating areas:			
Lease operating expenses	\$0.82	\$0.76	\$0.63
Production taxes	0.23	0.11	0.06
Transportation and compression	0.21	0.19	0.17
	\$1.26	\$1.05	\$0.86
Total production costs:			
Lease operating expenses ⁽⁴⁾	\$1.29	\$1.09	\$0.82
Production taxes	0.27	0.18	0.12
Transportation and compression	0.25	0.24	0.24
	\$1.81	\$1.50	\$1.19

(1) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia (excluding the Cedar Bluff area); Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the County Line area of Wyoming; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

- (2) “Mcf” represents thousand cubic feet; “Mcf_e” represents thousand cubic feet equivalents; and “Bbl” represents barrels.
- (3) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the years ended December 31, 2014, 2013, and 2012. Including the effect of this subordination, the average realized gas sales price was \$3.66 per Mcf (\$3.84 per Mcf before the effects of financial hedging), \$3.21 per Mcf (\$2.99 per Mcf before the effects of financial hedging), and \$2.76 per Mcf (\$2.08 per Mcf before the effects of financial hedging) for the years ended December 31, 2014, 2013, and 2012, respectively.
- (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 for the years ended December 31, 2014, 2013, and 2012. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were \$0.96 per Mcfe (\$1.47 per Mcfe for total production costs), \$0.69 per Mcfe (\$1.23 per Mcfe for total production costs), and \$0.48 per Mcfe (\$0.94 per Mcfe for total production costs) for the years ended December 31, 2014, 2013, and 2012, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were \$1.27 per Mcfe (\$1.79 per Mcfe for total production costs), \$1.01 per Mcfe (\$1.42 per Mcfe for total production costs), and \$0.58 per Mcfe (\$0.94 per Mcfe for total production costs) for the years ended December 31, 2014, 2013, and 2012, respectively.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Total production revenues were \$454.0 million for the year ended December 31, 2014, an increase of \$187.2 million from \$266.8 million for the year ended December 31, 2013. This increase principally consisted of a \$115.7 million increase attributable to the coal-bed methane assets, a \$51.0 million increase attributable to the newly acquired Rangely/Eagle Ford assets, a \$13.0 million increase attributable to the Mississippi Lime/Hunton assets, a \$5.3 million increase attributable to the Appalachia assets due primarily to the Marcellus and Utica Shale wells drilled, and a \$4.0 million increase attributable to the Barnett Shale/Marble Falls operations.

Total production costs were \$176.2 million for the year ended December 31, 2014, an increase of \$79.0 million from \$97.2 million for the year ended December 31, 2013. This increase primarily consisted of a \$50.5 million increase attributable to production costs associated with the newly acquired coal-bed methane assets, a \$16.3 million increase attributable to the newly acquired Rangely/Eagle Ford assets, a \$4.4 million increase attributable to the Barnett Shale/Marble Falls assets, a \$3.4 million increase attributable to the Mississippi Lime/Hunton assets, a \$3.1 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships, and a \$1.3 million increase attributable to Appalachia operations. Total production costs per Mcfe increased to \$1.81 per Mcfe for the year ended December 31, 2014 from \$1.50 per Mcfe for the comparable prior year period primarily as a result of the increases in our oil and natural gas liquids production.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Total production revenues were \$266.8 million for the year ended December 31, 2013, an increase of \$173.9 million from \$92.9 million for the year ended December 31, 2012. This increase principally consisted of a \$92.3 million increase attributable to the Barnett Shale/Marble Falls operations, a \$66.1 million increase attributable to the newly acquired coal-bed methane assets, a \$15.4 million increase attributable to the Mississippi Lime/Hunton assets, and a \$2.1 million increase attributable to the Appalachia assets due primarily to new Marcellus and Utica Shale wells drilled.

Total production costs were \$97.2 million for the year ended December 31, 2013, an increase of \$70.6 million from \$26.6 million for the year ended December 31, 2012. This increase was due primarily to a \$39.7 million increase associated with our 2012 acquisitions in the Barnett Shale/Marble Falls and Mississippi Lime/Hunton plays, a \$25.8 million increase associated with our 2013 acquisition of coal-bed methane assets, a \$3.6 million increase in our Appalachia-based transportation, labor and other production costs, and a \$1.4 million decrease in the credit received against our lease operating expenses pertaining to the subordination of revenue within our Drilling Partnerships. Total production costs per Mcfe increased to \$1.50 per Mcfe for the year ended December 31, 2013 from \$1.19 per Mcfe for the comparable prior year period primarily as a result of the increase in our oil and natural gas liquids volumes during the year ended December 31, 2013.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling Partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table presents the amounts of Drilling Partnership investor capital raised and deployed (in thousands), as well as the number of gross and net development wells we drilled for our Drilling Partnerships during years ended December 31, 2014, 2013, and 2012. There were no exploratory wells drilled during the years ended December 31, 2014, 2013, and 2012:

	Years Ended December 31,		
	2014	2013	2012
Drilling partnership investor capital:			
Raised	\$ 166,798	\$ 149,967	\$ 127,071
Deployed	\$ 173,564	\$ 167,883	\$ 131,496
Gross partnership wells drilled:			
Appalachia			
Marcellus Shale	—	—	10
Utica	4	3	5
Ohio	—	—	7
Barnett/Marble Falls	77	51	4
Eagle Ford	2	—	—
Mississippi Lime/Hunton	17	21	11
Niobrara	—	—	51
Total	100	75	88
Net partnership wells drilled:			
Appalachia			
Marcellus Shale	—	—	10
Utica	4	3	5
Ohio	—	—	7
Barnett/Marble Falls	64	25	2
Eagle Ford	1	—	—
Mississippi Lime/Hunton	16	21	9
Niobrara	—	—	51
Total	85	49	84

Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for Drilling Partnerships we sponsor. The following table sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Years Ended December 31,		
	2014	2013	2012
Average construction and completion:			
Revenue per well	\$2,227	\$3,276	\$1,444
Cost per well	1,937	2,849	1,253
Gross profit per well	\$290	\$427	\$191
Gross profit margin	\$22,639	\$21,898	\$17,417
Partnership net wells associated with revenue recognized ⁽¹⁾ :			
Appalachia			
Marcellus Shale	—	4	7
Utica	3	5	2
Ohio	—	—	8
Barnett/Marble Falls	60	24	2
Eagle Ford	1	—	—
Mississippi Lime/Hunton	14	18	7
Chattanooga	—	—	2
Niobrara	—	—	63
Total	78	51	91

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

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Well construction and completion segment margin was \$22.6 million for year ended December 31, 2014, an increase of \$0.7 million from \$21.9 million for the year ended December 31, 2013. This increase consisted of a \$7.7 million increase related to a greater number of wells recognized for revenue within our Drilling Partnerships, partially offset by a \$7.0 million decrease associated with lower gross profit margin per well. Average revenue and cost per well decreased between periods due primarily to capital deployed for lower cost Marble Falls wells within the Drilling Partnerships during the year ended December 31, 2014 compared with capital deployed for higher cost Marcellus and Utica Shale wells during the prior year period. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Well construction and completion segment margin was \$21.9 million for the year ended December 31, 2013, an increase of \$4.5 million from \$17.4 million for the year ended December 31, 2012. This increase consisted of a \$12.1 million increase associated with higher gross profit margin per well, partially offset by a \$7.6 million decrease related to a lower number of wells recognized for revenue within our Drilling Partnerships. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Utica Shale, Mississippi Lime play, and Marble Falls play wells within the Drilling Partnerships during the year ended December 31, 2013, compared with higher capital deployed for lower cost Niobrara Shale wells during the prior year period.

At December 31, 2014, our consolidated balance sheet includes \$40.6 million of “liabilities associated with well drilling contracts” for funds raised by our Drilling Partnerships that have not been applied to the completion of wells due to the timing of drilling operations, and thus had not been recognized as well construction and completion revenue on our consolidated statement of operations. We expect to recognize this amount as revenue during 2015.

Administration and Oversight

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our Drilling Partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the Drilling Partnerships, such as those in the Marble Falls play and Niobrara Shale, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Administration and oversight fee revenues were \$15.6 million for the year ended December 31, 2014, an increase of \$3.3 million from \$12.3 million for the year ended December 31, 2013. This increase was due to increases in the number of wells spud within the current year period compared with the prior year period, particularly within the Marble Falls play.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Administration and oversight fee revenues were \$12.3 million for the year ended December 31, 2013, an increase of \$0.5 million from \$11.8 million for the year ended December 31, 2012. This increase was due primarily to current year period increases in the number of wells drilled within the Mississippi Lime and Marble Falls plays, partially offset by a decrease in the number of Marcellus Shale wells drilled during the year ended December 31, 2013.

Well Services

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

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Well services revenues were \$25.0 million for the year ended December 31, 2014, an increase of \$5.5 million from \$19.5 million for the year ended December 31, 2013. Well services expenses were \$10.0 million for the year ended December 31, 2014, an increase of \$0.5 million from \$9.5 million for the year ended December 31, 2013. The increase in well services revenue is primarily related to the increased utilization of our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls plays by Drilling Partnership wells. The increase in well services expense is primarily related to higher labor costs.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Well services revenues were \$19.5 million for the year ended December 31, 2013, a decrease of \$0.5 million from \$20.0 million for the year ended December 31, 2012. Well services expenses were \$9.5 million for the year ended December 31, 2013, an increase of \$0.2 million from \$9.3 million for the year ended December 31, 2012. The decrease in well services revenue is primarily related to lower equipment rental revenue during the year ended December 31, 2013 as compared with the comparable prior year period. The increase in well services expense is primarily related to higher well labor costs.

Gathering and Processing

Gathering and processing margin includes gathering fees we charge to our Drilling Partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale. Generally, we charge a gathering fee to our Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13%

gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Our net gathering and processing expense for the year ended December 31, 2014 was \$1.4 million, a decrease of \$0.9 million compared with net expense of \$2.3 million for the year ended December 31, 2013. This favorable movement was principally due to a full year of gathering fees from the Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Our net gathering and processing expense for the year ended December 31, 2013 was \$2.3 million, a decrease of \$0.9 million compared with net expense of \$3.2 million for the year ended December 31, 2012. This favorable decrease was principally due to an increase in gathering fees associated with our new Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania.

Other, net

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Other, net for the year ended December 31, 2014 was income of \$3.4 million, compared with expense of \$14.5 million for the year ended December 31, 2013. The \$17.9 million favorable movement compared with the prior year period was primarily related to the \$14.5 million of premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from EP Energy in the prior year period and a \$2.8 million gain on mark-to-market derivatives in the current year.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Other, net for the year ended December 31, 2013 was an expense of \$14.5 million, compared with expense of \$4.9 million for the year ended December 31, 2012. The \$14.5 million of other expense for the year ended December 31, 2013 was primarily related to premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from EP Energy in the current year period. The \$4.9 million of other expense for the year ended December 31, 2012 was primarily related to the premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from Carrizo during the prior year period.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Total general and administrative expenses decreased to \$72.3 million for the year ended December 31, 2014 compared with \$78.1 million for the year ended December 31, 2013. This decrease was primarily due to a \$12.1 million decrease in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods and a \$4.6 million decrease in non-cash compensation expense, partially offset by a \$7.0 million increase in salaries, wages and benefits and a \$3.9 million increase in other corporate activities due to the growth of our business.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Total general and administrative expenses increased to \$78.1 million for the year ended December 31, 2013 compared with \$69.1 million for the year ended December 31, 2012. This increase was primarily due to a \$7.7 million increase in non-recurring transaction costs related to the acquisitions of assets during the year ended December 31, 2013 and the prior year period and a \$1.8 million increase in non-cash compensation expense, partially offset by a \$0.5 million decrease in other corporate activities.

Chevron Transaction Expense

During the year ended December 31, 2012, we recognized a \$7.7 million charge regarding our reconciliation process with Chevron related to certain amounts included within the contractual cash transaction adjustment, which was settled in October 2012 (see “Item 8: Financial Statements and Supplementary Data – Note 3”).

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization increased to \$233.7 million for the year ended December 31, 2014 compared with \$136.8 million for the comparable prior year period, which was primarily due to a \$93.7 million increase in our depletion expense resulting from the acquisitions we consummated during 2014 and 2013.

Total depreciation, depletion and amortization increased to \$136.8 million for the year ended December 31, 2013 compared with \$52.6 million for the comparable prior year period, which was due to an \$82.7 million increase in our depletion expense resulting from the acquisitions we consummated during 2012 and 2013.

The following table presents a summary of our depreciation, depletion and amortization expense and our depletion expense per Mcfe for our operations for the respective periods (in thousands, except for per Mcfe data):

	Years Ended December 31,		
	2014	2013	2012
Depreciation, depletion and amortization:			
Depletion expense	\$223,358	\$129,729	\$47,000
Depreciation and amortization expense	10,373	7,034	5,582
	\$233,731	\$136,763	\$52,582
Depletion expense:			
Total	\$223,358	\$129,729	\$47,000
Depletion expense as a percentage of gas and oil production revenue	49 %	49 %	51 %
Depletion per Mcfe	\$2.27	\$1.89	\$1.66

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties.

For the year ended December 31, 2014, depletion expense was \$223.4 million, an increase of \$93.7 million compared with \$129.7 million for the year ended December 31, 2013. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 49% for the year ended December 31, 2014, which was consistent with 49% for the year ended December 31, 2013. Depletion expense per Mcfe increased to \$2.27 for the year ended December 31, 2014, compared to \$1.89 for the prior year comparable period, which was primarily due to an increase in depletion expense associated with our oil and natural gas liquids wells drilled between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

For the year ended December 31, 2013, depletion expense was \$129.7 million, an increase of \$82.7 million compared with \$47.0 million for the year ended December 31, 2012. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 49% for the year ended December 31, 2013, compared with 51% for the year ended December 31, 2012, which was primarily due to an increase in our oil and natural gas liquids revenues as a result of our acquisitions in 2012, partially offset by a decrease in realized natural gas prices between the periods. Depletion expense per Mcfe increased to \$1.89 for the year ended December 31, 2013, compared to \$1.66 for the prior year comparable period primarily due to the increase in oil and natural gas liquids production between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

Asset Impairment

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Asset impairment for the year ended December 31, 2014 was \$573.8 million as compared with \$38.0 million for the comparable prior year period. The \$573.8 million of asset impairment primarily consisted of \$555.7 million of oil and gas impairment within our Appalachian and mid-continent operations, which was reduced by \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income. In addition, \$18.1 million of asset impairment is due to goodwill impairment. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014 through the impairment testing date in January 2015. During the year ended December 31, 2013, we recognized \$38.0 million of asset impairment related to impairments of gas and oil properties within property, plant and equipment, net on our consolidated balance sheet primarily for our shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. These impairments related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair values at December 31, 2014 and 2013 and our intention not to drill on certain expiring unproved acreage. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of commodity prices in comparison to their carrying values at December 31, 2014 and 2013.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Asset impairment for the year ended December 31, 2013 was \$38.0 million as compared with \$9.5 million for the comparable prior year period. The \$38.0 million of asset impairment during the year ended December 31, 2013 was related to impairments of gas and oil properties within property, plant and equipment, net on our consolidated balance sheet primarily for our shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. During

the year ended December 31, 2012, we recognized \$9.5 million of asset impairment related to gas and oil properties within property, plant and equipment on our consolidated balance sheet for our shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of these gas and oil properties being in excess of our estimates of their fair values at December 31, 2013 and 2012 and our intention not to drill on certain expiring unproved acreage. The estimates of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices in comparison to their carrying values at December 31, 2013 and 2012.

Interest Expense

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. Interest expense for the year ended December 31, 2014 was \$62.1 million as compared with \$34.3 million for the comparable prior year period. The \$27.8 million increase consisted of a \$20.7 million increase associated with interest expense on our senior notes, a \$6.4 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility, a \$0.2 million increase in the amortization of the 7.75% and 9.25% senior notes' discounts, and interest that was capitalized on our ongoing capital projects, partially offset by a \$0.4 million decrease associated with amortization of deferred financing costs and a \$0.3 million decrease in commitment fees. The increase in interest expense related to our senior notes is primarily due to the issuance of an additional \$100.0 million of our 7.75% Senior Notes in June 2014 and an additional \$75.0 million of our 9.25% Senior Notes in October 2014, as well as a full year of interest expense related to the \$275.0 million 7.75% Senior Notes issued in January 2013 and \$250.0 million of 9.25% Senior Notes issued in July 2013.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. Interest expense for the year ended December 31, 2013 was \$34.3 million as compared with \$4.2 million for the comparable prior year period. The \$30.1 million increase consisted of a \$20.9 million increase associated with the issuance of our 7.75% Senior Notes, a \$10.1 million increase associated with the issuance of our 9.25% Senior Notes, a \$7.8 million increase associated with amortization of deferred financing costs, and a \$3.1 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility and then-existing term loan credit facility, partially offset by interest that was capitalized on our ongoing capital projects. The increase in amortization associated with deferred financing costs includes \$5.3 million associated with our revolving credit facility, \$3.2 million of accelerated amortization related to the retirement of our then-existing term loan credit facility and the reduction in our revolving credit facility borrowing base subsequent to our issuance of the 7.75% Senior Notes and \$1.2 million associated with our issuance of senior notes, partially offset by a \$1.9 million decrease in amortization expense related to the extension of our credit facility maturity date from 2016 to 2018.

Loss on Asset Sales and Disposal

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013. During the years ended December 31, 2014 and 2013, we recognized losses on asset sales and disposal of \$1.9 million and \$1.0 million, respectively. The \$1.9 million loss on asset sales and disposal for the year ended December 31, 2014 was primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement and a \$0.3 million loss on the involuntary conversion of the Mossy Oak compressor station. The \$1.0 million loss on asset sales and disposal for the year ended December 31, 2013 primarily pertained to a loss on the sale of our Antrim assets in Michigan.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012. During the years ended December 31, 2013 and 2012, we recognized losses on asset sales and disposal of \$1.0 million and \$7.0 million, respectively. The \$1.0 million loss on asset sales and disposal for the year ended December 31, 2013 primarily pertained to a loss on the sale of our Antrim assets in Michigan. During the year ended December 31, 2012, we recognized a \$7.0 million loss on asset sales and disposal related to management's decision to terminate a farm-out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm-out agreement contained certain well drilling milestones, which needed to be met in order for us to maintain ownership of the South Knox processing plant. During 2012, management decided not to continue progressing towards these milestones due to the current natural gas price environment. As a result, we forfeited our interest in the processing plant and recorded a loss related to the net book value of the assets during the year ended December 31, 2012.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary sources of liquidity are cash generated from operations, capital raised through our Drilling Partnerships, and borrowings under our revolving credit facility (see “Credit Facility”). Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and distributions to our limited partners and general partner. In general, we expect to fund:

cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;

expansion capital expenditures and working capital deficits through cash generated from operations, additional borrowings and capital raised through Drilling Partnerships; and

debt principal payments through additional borrowings as they become due or by the issuance of additional common units or asset sales.

We rely on cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve month period. However, we are subject to business, operational and other risks that could adversely affect our cash flow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units, the sale of assets and other transactions.

Cash Flows – Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

Net cash provided by operating activities of \$190.4 million for the year ended December 31, 2014 represented a favorable movement of \$67.5 million from net cash provided by operating activities of \$122.9 million for the prior year. The \$67.5 million favorable movement in net cash provided by operating activities resulted from a \$108.9 million favorable movement in net income excluding non-cash items, partially offset by a \$41.4 million unfavorable movement in working capital. The \$108.9 million favorable movement in net income excluding non-cash items consisted principally of a \$136.9 million increase in operating cash flow, which was primarily due to our consummation of the EP Energy, GeoMet, Rangely and Eagle Ford acquisitions, partially offset by a \$28.0 million increase in cash interest expense principally due to our Senior Notes offerings in July 2013 and June 2014. The \$41.4 million unfavorable movement in working capital was principally due to a \$74.6 million unfavorable movement in accounts receivable, prepaid expenses and other, partially offset by a \$33.2 million favorable movement in accounts payable and accrued liabilities. The \$74.6 million unfavorable movement in accounts receivable, prepaid expenses and other was principally due to an unfavorable movement in accounts receivable due to the timing of cash receipts during the year ended December 31, 2014 compared with the year ended December 31, 2013. The \$33.2 million favorable movement in accounts payable and accrued liabilities was primarily due to a favorable movement in accounts payable due to the timing of payments and the growth of our business during the year ended December 31, 2014 compared with the year ended December 31, 2013.

Net cash used in investing activities of \$896.4 million for year ended December 31, 2014 represented a favorable movement of \$88.2 million from net cash used in investing activities of \$984.6 million for the prior year. This favorable movement was primarily due to a \$50.9 million decrease in capital expenditures, a \$31.0 million decrease in net cash paid for acquisitions in 2014 as compared to the prior year and a \$6.3 million favorable movement in other assets. See further discussion of capital expenditures under “Capital Requirements”.

Net cash provided by financing activities of \$719.4 million for the year ended December 31, 2014 represented an unfavorable movement of \$120.9 million from net cash provided by financing activities of \$840.3 million for the prior year. This movement was principally due to a \$339.8 million decrease in net proceeds from long-term debt, a \$241.6 million increase in repayments under our revolving credit facility, a \$94.1 million increase in cash distributions paid to limited partners and a \$9.3 million decrease in net proceeds from the issuance of our preferred limited partner units and warrants, partially offset by a \$451.0 million increase in borrowings under our revolving credit facility, a \$106.3 million increase in net proceeds from the issuance of our common limited partner units and a \$6.6 million favorable movement in deferred financing costs, distribution equivalent rights and other. The gross amount of borrowings and repayments under our revolving credit facility included within net cash provided by financing activities, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under our revolving credit facility, and payments, which generally occur throughout the period and increase borrowings under our revolving credit facility, which is generally common practice for our industry.

The deferred portion of the purchase price related to the Eagle Ford Acquisition (see “Recent Developments”) represented a non-cash transaction during the year ended December 31, 2014.

Cash Flows – Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

Net cash provided by operating activities of \$122.9 million for the year ended December 31, 2013 represented a favorable movement of \$106.4 million from net cash provided by operating activities of \$16.5 million for 2012. The \$106.4 million favorable movement in net cash provided by operating activities resulted from a \$77.0 million favorable movement in net income excluding non-cash items and a \$29.4 million favorable movement in working capital. The \$77.0 million favorable movement in net income excluding non-cash items included an \$84.2 million increase in depreciation, depletion and amortization expense, a \$28.5 million favorable movement in asset impairment, a \$7.7 million increase in amortization of deferred financing costs relating to our revolving and then-existing term loan credit facilities and our senior notes (see “Senior Notes”), and a \$1.9 million increase in non-cash stock compensation, partially offset by a \$39.3 million unfavorable movement in net loss and a \$6.0 million unfavorable movement in (gain)/loss on asset sales and disposal. The \$84.2 million increase in depreciation, depletion and amortization expense is primarily related to the acquisitions of oil and gas properties made in 2012 and 2013. The \$29.4 million favorable movement in working capital was principally due to a \$54.3 million favorable movement in accounts receivable, prepaid expenses and other, partially offset by a \$24.9 million unfavorable movement in accounts payable and accrued liabilities. The favorable movement in accounts receivable, prepaid expenses and other was primarily due to a favorable movement in subscriptions receivable due to the timing of funds raised. The unfavorable movement in accounts payable and accrued liabilities was primarily due to an unfavorable movement in accrued well drilling and completion costs between respective periods.

Net cash used in investing activities of \$984.6 million for the year ended December 31, 2013 represented an unfavorable movement of \$340.3 million from net cash used in investing activities of \$644.3 million for 2012. This unfavorable movement was primarily due to an increase in net cash paid for acquisitions during the year ended December 31, 2013 as compared to the year ended December 31, 2012 and an increase in capital expenditures. See further discussion of capital expenditures under “Capital Requirements”.

Net cash provided by financing activities of \$840.3 million for the year ended December 31, 2013 represented a favorable movement of \$244.0 million from net cash provided by financing activities of \$596.3 million for 2012. This movement was principally due to an increase of \$510.4 million in net proceeds from the issuance of our senior notes (see “Senior Notes”), an increase of \$274.9 million in borrowings under our revolving credit facility, an increase of \$86.6 million from the issuance of our Class C preferred units and warrants and an increase of \$29.9 million in net proceeds from the issuance of our common limited partner units, partially offset by an increase of \$558.8 million in repayments under our revolving and then-existing term loan credit facilities, a \$91.1 million increase in cash distributions paid to unitholders, a \$5.6 million unfavorable movement in the net investment from owners and a \$2.3 million unfavorable movement in deferred financing costs, distribution equivalent rights and other. The gross amount of borrowings and repayments under our revolving credit facility included within net cash provided by financing activities in the consolidated statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under our revolving credit facility, and payments, which generally occur throughout the period and increase borrowings under our revolving credit facility, which is generally common practice for our industry.

Our July 2012 acquisition of Titan in exchange for 3.8 million common units and 3.8 million convertible Class B preferred units (which had an estimated collective value of \$193.2 million, based upon the closing price of our publicly traded units as of the acquisition close date) represented a non-cash transaction during the year ended December 31, 2012.

Capital Requirements

The capital requirements of our natural gas and oil production consist primarily of:

maintenance capital expenditures — oil and gas assets naturally decline in future periods and, as such, we recognize the estimated capitalized cost of stemming such decline in production margin for the purpose of stabilizing our distributable cash flow and cash distributions, which we refer to as maintenance capital expenditures. We calculate the estimate of maintenance capital expenditures by first multiplying forecasted future full year production margin by expected aggregate production decline of proved developed producing wells. Maintenance capital expenditures are then the estimated capitalized cost of wells that will generate an estimated first year margin equivalent to the production margin decline, assuming such wells are connected on the first day of the calendar year. We do not incur specific capital expenditures expressly for the purpose of maintaining or increasing production margin, but such

amounts are a subset of hypothetical wells we expect to drill in future periods, including Marcellus Shale, Utica Shale, Mississippi Lime and Marble Falls wells, on undeveloped acreage already leased. Estimated capitalized cost of wells included within maintenance capital expenditures are also based upon relevant factors, including historical costs of similar wells and characteristics of each individual well. First year margin from wells included within maintenance capital are also based upon relevant factors, including utilization of public forward commodity exchange prices, current estimates for regional pricing differentials, estimated labor and material rates and other production costs. Estimates for maintenance capital expenditures in the current year are the sum of the estimate calculated in the prior year plus estimates for the decline in production margin from wells connected during the current year and production acquired through acquisitions; and

expansion capital expenditures — we consider expansion capital expenditures to be any capital expenditure costs expended that are not maintenance capital expenditures – generally, this will include expenditures to increase, rather than maintain, production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures.

The following table summarizes our maintenance and expansion capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Years Ended December 31,		
	2014	2013	2012
Maintenance capital expenditures	\$65,300	\$31,500	\$10,200
Expansion capital expenditures	147,334	232,037	117,026
Total	\$212,634	\$263,537	\$127,226

During the year ended December 31, 2014, our \$212.6 million of total capital expenditures consisted primarily of \$82.2 million for wells drilled exclusively for our own account compared with \$110.8 million for the prior year, \$72.4 million of investments in our Drilling Partnerships compared with \$92.3 million for the prior year, \$25.5 million of leasehold acquisition costs compared with \$20.9 million for the prior year, and \$32.5 million of corporate and other costs compared with \$39.5 million for the prior year, which primarily related to a decrease in gathering and processing costs.

During the year ended December 31, 2013, our \$263.5 million of total capital expenditures consisted primarily of \$110.8 million for wells drilled exclusively for our own account compared with \$27.3 million for 2012, \$92.3 million of investments in our Drilling Partnerships compared with \$54.4 million for 2012, \$20.9 million of leasehold acquisition costs compared with \$35.6 million for 2012, and \$39.5 million of corporate and other costs compared with \$9.9 million for 2012, which primarily related to an increase in capitalized interest expense.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisitions in the future, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of December 31, 2014, we are committed to expend approximately \$18.9 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our Drilling Partnerships and borrowings under our revolving credit facility.

OFF BALANCE SHEET ARRANGEMENTS

As of December 31, 2014, our off-balance sheet arrangements were limited to our letters of credit outstanding of \$4.4 million and commitments to spend \$18.9 million related to our drilling and completion and capital expenditures, excluding acquisitions.

We are the managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of December 31, 2014, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

In connection with the Eagle Ford Acquisition (see "Recent Developments"), we guaranteed the Development Subsidiary's deferred purchase obligation, whereby we provided a guaranty of timely payment of the deferred portion of the purchase price that is to be paid by the Development Subsidiary. Pursuant to the agreement between us and the Development Subsidiary, we will have the right to receive some or all of the assets acquired by the Development Subsidiary in the event of its failure to contribute its portion of any deferred payments.

CASH DISTRIBUTION POLICY

Our partnership agreement requires that we distribute 100% of available cash to our common and preferred unitholders and general partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments. Our general partner is granted discretion under the partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated.

On January 29, 2014, our board of directors approved a modification to our cash distribution payment practice to a monthly cash distribution program. Monthly cash distributions are paid approximately 45 days following the end of each respective monthly period.

Available cash will generally be distributed: first, 98% to our Class B and D preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class B preferred unit the greater of \$0.40 per quarter and the distribution payable to common unitholders and with respect to our Class D preferred unit, an amount equal to its fixed quarterly distribution; second, 98% to our Class C preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class C preferred unit the greater of \$0.51 per quarter and the distribution payable to common unitholders; thereafter 98% to our common unitholders and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner, if quarterly distributions exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The incentive distribution rights will entitle our general partner to receive the following increasing percentage of cash distributed by us as it reaches certain target distribution levels:

13.0% of all cash distributed in any quarter after each common unit has received \$0.46 for that quarter;

23.0% of all cash distributed in any quarter after each common unit has received \$0.50 for that quarter; and

48.0% of all cash distributed in any quarter after each common unit has received \$0.60 for that quarter.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table summarizes our contractual obligations at December 31, 2014 (in thousands):

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	Total	Payments Due By Period			
		Less than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Contractual cash obligations:					
Total debt	\$ 1,396,000	\$—	\$—	\$ 696,000	\$ 700,000
Interest on total debt	446,952	79,279	158,559	129,989	79,125
Eagle Ford deferred payment ⁽¹⁾	24,000	24,000	—	—	—
Operating leases	17,545	3,903	6,397	4,152	3,093
Total contractual cash obligations	\$ 1,884,497	\$ 107,182	\$ 164,956	\$ 830,141	\$ 782,218

	Total	Amount of Commitment Expiration Per Period			
		Less than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
Other commercial commitments:					
Standby letters of credit	\$ 4,401	\$ 4,401	\$—	\$—	\$—
Other commercial commitments ⁽²⁾	39,731	20,101	8,203	4,555	6,872
Total commercial commitments	\$ 44,132	\$ 24,502	\$ 8,203	\$ 4,555	\$ 6,872

(1) In connection with the Eagle Ford Acquisition, we guaranteed the Development Subsidiary's deferred purchase obligation. See "Off Balance Sheet Obligations" for further information.

(2) Our other commercial commitments include our share of drilling and completion commitments and our throughput contracts, including firm transportation obligations for natural gas as a result of the EP Energy and GeoMet acquisitions. See "Contractual Revenue Arrangements" for a description of our firm transportation obligations.

ENVIRONMENTAL REGULATION

Our operations are subject to federal, state and local laws and regulations governing the release of regulated materials into the environment or otherwise relating to environmental protection or human health or safety (see “Item 1: Business—Environmental Matters and Regulation”). We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; imposition of remedial requirements; issuance of injunctions affecting our operations; or other measures. We have maintained and expect to continue to maintain environmental compliance programs. However, risks of accidental leaks or spills are associated with our operations. There can be no assurance that we will not incur significant costs and liabilities relating to claims for damages to property, the environment, natural resources, or persons resulting from the operation of our and our subsidiaries’ business. Moreover, it is possible other developments, such as increasingly strict federal, state and local environmental laws and regulations and enforcement policies, could result in increased costs and liabilities to us and our subsidiaries.

Environmental laws and regulations have changed substantially and rapidly over the last 25 years, and we anticipate that there will be continuing changes. Trends in environmental regulation include increased reporting obligations and placing more restrictions and limitations on activities, such as emissions of greenhouse gases and other pollutants; generation and disposal of wastes, including wastes that may have naturally occurring radioactivity; and use, storage and handling of chemical substances that may impact human health, the environment and/or threatened or endangered species. Other increasingly stringent environmental restrictions and limitations have resulted in increased operating costs for us and other similar businesses throughout the United States. It is possible that the costs of compliance with environmental laws and regulations may continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly, but there can be no assurance that we will identify and properly anticipate each such change, or that our efforts will prevent material costs, if any, from rising.

CREDIT FACILITY

On February 23, 2015, we entered into a Sixth Amendment to the Second Amended and Restated Credit Agreement and a Second Lien Credit Agreement (see “Subsequent Events”). On November 24, 2014, we entered into a Fifth Amendment to the Second Amended and Restated Credit Agreement with Wells Fargo Bank National Association, as administrative agent, and the lenders party thereto, among us as borrower, the administrative agent and the lenders party thereto (the “Credit Agreement”). The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a current borrowing base of \$900.0 million and a maximum facility amount of \$1.5 billion scheduled to mature in July 2018.

The Fifth Amendment was entered into in connection with the previously announced restructuring of our general partner, and the sale of Atlas Energy and its midstream interest (see “Subsequent Events”). Among other things, the

Fifth Amendment amended several definitions for the purpose of ensuring that the transaction did not result in a Change of Control or Event of Default determination under the Credit Agreement (each as defined in the Credit Agreement).

Our borrowing base is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. At December 31, 2014, \$696.0 million was outstanding under the credit facility. Up to \$20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which \$4.4 million was outstanding at December 31, 2014. Our obligations under the facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets. Additionally, obligations under the facility are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor. Borrowings under the credit facility bear interest, at our election, at either an adjusted LIBOR rate plus an applicable margin between 1.50% and 2.75% per annum or the base rate (which is the higher of the bank's prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 0.50% and 1.75% per annum. We are also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on our consolidated statements of operations.

The Credit Agreement contains customary covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. We were in compliance with these covenants as of December 31, 2014. The Credit Agreement also requires us to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended on June 30, 2014, September 30, 2014 and December 31, 2014, 4.25 to 1.0 as of the last day of the quarter ending March 31, 2015, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

SENIOR NOTES

At December 31, 2014, we had \$374.5 million outstanding of our 7.75% Senior Notes, including \$100.0 million of such notes issued in a private placement transaction on June 2, 2014 at an offering price of 99.5% of par value, yielding net proceeds of approximately \$97.4 million. The net proceeds were used to partially fund the Rangely Acquisition (see “Recent Developments”). The 7.75% Senior Notes were presented net of a \$0.5 million unamortized discount as of December 31, 2014. We issued \$275.0 million of our 7.75% Senior Notes in a private placement transaction at par on January 23, 2013. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019.

At December 31, 2014, we had \$323.9 million outstanding of our 9.25% Senior Notes, including \$75.0 million of such notes issued in a private placement transaction on October 14, 2014 at an offering price of 100.5% of par value, which yielded net proceeds of approximately \$73.6 million. The 9.25% Senior Notes issued in October 2014 were presented net of a \$0.4 million unamortized premium as of December 31, 2014. We used the net proceeds from this offering to fund a portion of our Eagle Ford Acquisition (see “Recent Developments”). The 9.25% Senior Notes issued in July 2013 were presented net of a \$1.5 million unamortized discount as of December 31, 2014. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time on or after August 15, 2017, we may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, we may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, we may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, we may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if we experience specific kinds of changes of control, we must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the \$75.0 million of 9.25% Senior Notes on October 14, 2014, we entered into a registration rights agreement whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated not later than 270 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If we fail to comply with our obligations to register the 9.25% Senior Notes within the specified time periods, we will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several, and any subsidiaries of ours, other than the subsidiary guarantors, are minor. There are no restrictions on our ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants, including limitations of our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We were in compliance with these covenants as of December 31, 2014.

SECURED HEDGE FACILITY

At December 31, 2014, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

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

ISSUANCE OF UNITS

In October 2014, in connection with the Eagle Ford Acquisition (see "Recent Developments"), we issued 3,200,000 8.625% Class D preferred units at a public offering price of \$25.00 per Class D preferred unit, yielding net proceeds of approximately \$77.4 million from the offering, after deducting underwriting discounts and estimated offering expenses. We used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition. On January 15, 2015, we paid an initial quarterly distribution of \$0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015. We will pay future cumulative distributions on a quarterly basis, at an annual rate of \$2.15625 per unit, or 8.625% of the liquidation preference.

The Class D preferred units rank senior to our common units and Class C convertible preferred units with respect to the payment of distributions and distributions upon a liquidation event and equal with our Class B convertible preferred units. The Class D preferred units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by us or converted into our common units in connection with a change in control. At any time on or after October 15, 2019, we may, at our

option, redeem the Class D preferred units in whole or in part, at a redemption price of \$25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we may redeem the Class D preferred units following certain changes of control, as described in the Certificate of Designation. If we do not exercise this redemption option upon a change of control, then holders of the Class D preferred units will have the option to convert the Class D preferred units into a number of our common units per Class D preferred unit as set forth in the Certificate of Designation. If we exercise any of our redemption rights relating to the Class D preferred units, the holders of such Class D preferred units will not have the conversion right described above with respect to the Class D preferred units called for redemption.

In August 2014, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the “Agents”). Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to \$100.0 million. Sales of common units, if any, may be made in negotiated transactions or transactions that are deemed to be “at-the-market” offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent. As of December 31, 2014, no units have been sold under this program.

In May 2014, in connection with the Rangely Acquisition (see “Recent Developments”), we issued 15,525,000 of our common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of \$19.90 per unit, yielding net proceeds of approximately \$297.3 million. The units were registered under the Securities Act, pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

In March 2014, in connection with the GeoMet Acquisition (see “Recent Developments”), we issued 6,325,000 of our common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of \$21.18 per unit, yielding net proceeds of approximately \$129.0 million. The units were registered under the Securities Act, pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depletion, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. We summarize our significant accounting policies within our consolidated financial statements included in “Item 8: Financial Statements and Supplementary Data – Note 2” included in this report. The critical accounting policies and estimates we have identified are discussed below.

Depreciation and Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets. The cost of property, plant and equipment, less estimated salvage value, is generally depreciated on a straight-line basis over the estimated useful lives of the assets. Useful lives are based on historical experience and are adjusted when changes in planned use, technological advances or other factors indicate that a different life would be more appropriate. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively.

Long-lived assets, other than goodwill and intangibles with infinite lives, generally consist of natural gas and oil properties and pipeline, processing and compression facilities and are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. A long-lived asset, other than goodwill and intangibles with infinite lives, is considered to be impaired when the undiscounted net cash

flows expected to be generated by the asset are less than its carrying amount. The undiscounted net cash flows expected to be generated by the asset are based upon our estimates that rely on various assumptions, including natural gas and oil prices, production and operating expenses. Any significant variance in these assumptions could materially affect the estimated net cash flows expected to be generated by the asset. As discussed in “General Trends and Outlook” within this section, recent increases in natural gas and oil drilling have driven an increase in the supply of natural gas and oil and put a downward pressure on domestic prices. Further declines in commodity prices may result in additional impairment charges in future periods.

During the year ended December 31, 2014, we recognized \$555.7 million of asset impairments related to oil and gas properties within our Appalachian and mid-continent operations, which was reduced by \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014 through the impairment testing date in January 2015. During the year ended December 31, 2013, we recognized \$38.0 million of asset impairments related to gas and oil properties within property, plant and equipment, net on our consolidated balance sheet for shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. During the year ended December 31, 2012, we recognized \$9.5 million of asset impairments related to gas and oil properties within property, plant and equipment, net on our consolidated balance sheet for shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of these gas and oil properties being in excess of our estimate of their fair values at December 31, 2014, 2013, and 2012 and our intention not to drill on certain expiring unproved acreage. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of commodity prices at the date of measurement.

Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions. Additional factors impacting the economic viability of long-lived assets are discussed under “Item 1A: Risk Factors” in this report.

Goodwill and Intangibles with Infinite Lives. Goodwill and intangibles with infinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized if the carrying value of an entity’s reporting units exceeds its estimated fair value.

As a result of our impairment evaluation at December 31, 2014, we recognized an \$18.1 million non-cash impairment charge within asset impairment on our consolidated statement of operations for the year ended December 31, 2014. Our estimated fair value of the gas and oil production reporting unit was impacted by a decline in overall commodity prices during the fourth quarter of 2014. These estimates were subjective and based upon numerous assumptions about future operations and market conditions, which are subject to change. There were no goodwill impairments recognized by us during the years ended December 31, 2013 and 2012.

Fair Value of Financial Instruments

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

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

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

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

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

Liabilities that are required to be measured at fair value on a nonrecurring basis include our asset retirement obligations that are defined as Level 3. Estimates of the fair value of asset retirement obligations are based on discounted cash flows using numerous estimates, assumptions, and judgments regarding the cost, timing of settlement, our credit-adjusted risk-free rate and inflation rates.

During the years ended December 31, 2014, 2013, and 2012, we completed several acquisitions of oil and gas properties and related assets. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were measured under our existing methodology for recognizing an estimated liability for the plugging and abandonment of our gas and oil wells (see “Item 8: Financial Statements and Supplementary Data - Note 7”). These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

Reserve Estimates

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

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

Asset Retirement Obligations

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

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

The estimated liability is based on our historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted

risk-free interest rate. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Since there are many variables in estimating asset retirement obligations, we attempt to limit the impact of management's judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. We have no assets legally restricted for purposes of settling asset retirement obligations. Except for our gas and oil properties, we believe that there are no other material retirement obligations associated with tangible long lived assets.

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and interest rate cap and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2014. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties related to our commodity derivative contracts are banking institutions or their affiliates, who also participate in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we currently believe them to be financially viable. We are not aware of any inability on the part of our counterparties to perform under their contracts and believe our exposure to non-performance is remote.

Interest Rate Risk. At December 31, 2014, \$696.0 million was outstanding under our revolving credit facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would change our consolidated interest expense for the twelve month period ending December 31, 2015 by \$7.0 million.

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

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our consolidated operating income for the twelve-month period ending December 31, 2015 of approximately \$14.5 million.

Realized pricing of our natural gas, oil, and NGL production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production has been volatile and unpredictable for many years. To limit our exposure to changing natural gas, oil and NGL prices, we enter into natural gas and oil swap, put option and costless collar option contracts. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter (“OTC”) futures contracts with qualified counterparties. OTC contracts are generally financial contracts which are settled with financial payments or receipts and generally do not require delivery of

physical hydrocarbons. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. Crude oil contracts are based on a West Texas Intermediate (“WTI”) index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts have qualified and been designated as cash flow hedges and been recorded at their fair values.

At December 31, 2014, we had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu) ⁽¹⁾	Average Fixed Price (per MMBtu) ⁽¹⁾
2015	54,834,500	\$ 4.226
2016	53,546,300	\$ 4.229
2017	46,320,000	\$ 4.276
2018	35,760,000	\$ 4.250
2019	9,720,000	\$ 4.234

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu) ⁽¹⁾	Average Floor and Cap (per MMBtu) ⁽¹⁾
2015	Puts purchased	3,480,000	\$ 4.234
2015	Calls sold	3,480,000	\$ 5.129

Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu) ⁽¹⁾	Average Fixed Price (per MMBtu) ⁽¹⁾
2015	Puts purchased	1,440,000	\$ 4.000
2016	Puts purchased	1,440,000	\$ 4.150

Natural Gas – WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu) ⁽¹⁾	Average Fixed Price (per MMBtu) ⁽¹⁾
2015	5,250,000	\$ (0.082)

Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal) ⁽¹⁾	Average Fixed Price (per Gal) ⁽¹⁾
2015	5,040,000	\$ 1.983

Natural Gas Liquids – Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal) ⁽¹⁾	Average Fixed Price (per Gal) ⁽¹⁾
2015	8,064,000	\$ 1.016

Natural Gas Liquids – Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal) ⁽¹⁾	Average Fixed Price (per Gal) ⁽¹⁾
2015	1,512,000	\$ 1.248

Natural Gas Liquids – Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal) ⁽¹⁾	Average Fixed Price (per Gal) ⁽¹⁾
2015	1,512,000	\$ 1.263

Natural Gas Liquids – Crude Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl) ⁽¹⁾	Average Fixed Price (per Bbl) ⁽¹⁾
2016	84,000	\$ 85.651
2017	60,000	\$ 83.780

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl) ⁽¹⁾	Average Fixed Price (per Bbl) ⁽¹⁾
2015	1,743,000	\$ 90.645
2016	1,209,000	\$ 87.360
2017	672,000	\$ 85.669
2018	540,000	\$ 85.466

Crude Oil – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl) ⁽¹⁾	Average Floor and Cap (per Bbl) ⁽¹⁾
2015	Puts purchased	29,250	\$ 83.846

2015	Calls sold	29,250	\$ 110.654
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(1) “MMBtu” represents million British Thermal Units; “Bbl” represents barrels; “Gal” represents gallons.

ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Resource Partners, L.P.

We have audited the accompanying consolidated balance sheets of Atlas Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (collectively, the “Partnership”) as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income (loss), changes in partners’ capital, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlas Resource Partners, L.P. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership’s internal control over financial reporting as of December 31, 2014, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2015 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

March 2, 2015

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31,	
	2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 15,247	\$ 1,828
Accounts receivable	112,038	58,822
Current portion of derivative asset	141,366	1,891
Subscriptions receivable	32,398	47,692
Prepaid expenses and other	26,011	10,097
Total current assets	327,060	120,330
Property, plant and equipment, net	2,208,171	2,120,818
Intangible assets, net	691	963
Goodwill, net	13,639	31,784
Long-term derivative asset	127,933	27,084
Other assets, net	50,081	42,821
	\$ 2,727,575	\$ 2,343,800
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	\$ 109,049	\$ 69,346
Advances from affiliates	4,271	26,742
Liabilities associated with drilling contracts	40,611	49,377
Current portion of derivative liability	—	6,353
Current portion of derivative payable to Drilling Partnerships	932	2,676
Accrued well drilling and completion costs	80,404	40,481
Accrued interest	26,452	20,622
Distribution payable	20,876	—
Accrued liabilities	56,463	28,118
Total current liabilities	339,058	243,715
Long-term debt	1,394,460	942,334
Asset retirement obligations	106,528	89,776
Other long-term liabilities	2,033	684

Commitments and contingencies

Partners' Capital:

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General partner's interest	(13,697)	4,482
Preferred limited partners' interests	163,522	183,477
Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	548,586	852,457
Accumulated other comprehensive income	185,909	25,699
Total partners' capital	885,496	1,067,291
	\$2,727,575	\$2,343,800

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31,		
	2014	2013	2012
Revenues:			
Gas and oil production	\$453,957	\$266,783	\$92,901
Well construction and completion	173,564	167,883	131,496
Gathering and processing	14,107	15,676	16,267
Administration and oversight	15,564	12,277	11,810
Well services	24,959	19,492	20,041
Other, net	3,409	(14,456)	(4,886)
Total revenues	685,560	467,655	267,629
Costs and expenses:			
Gas and oil production	176,194	97,237	26,624
Well construction and completion	150,925	145,985	114,079
Gathering and processing	15,525	18,012	19,491
Well services	10,007	9,515	9,280
General and administrative	72,349	78,063	69,123
Chevron transaction expense	—	—	7,670
Depreciation, depletion and amortization	233,731	136,763	52,582
Asset impairment	573,774	38,014	9,507
Total costs and expenses	1,232,505	523,589	308,356
Operating loss	(546,945)	(55,934)	(40,727)
Interest expense	(62,144)	(34,324)	(4,195)
Loss on asset sales and disposal	(1,869)	(987)	(6,980)
Net loss	(610,958)	(91,245)	(51,902)
Preferred limited partner dividends	(19,267)	(11,992)	(3,063)
Net loss attributable to owner's interest, common limited partners and the general partner	\$(630,225)	\$(103,237)	\$(54,965)
Allocation of net income (loss):			
Portion applicable to owner's interest (period prior to the transfer of assets on March 5, 2012)	\$—	\$—	\$250
Portion applicable to common limited partners and the general partner's interests (period subsequent to the transfer of assets on March 5, 2012)	(630,225)	(103,237)	(55,215)
Net loss attributable to owner's interest, common limited partners and the general partner	\$(630,225)	\$(103,237)	\$(54,965)

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Allocation of net income (loss) attributable to common limited partners and the general partner:

Common limited partners' interest	\$ (628,926)	\$ (106,581)	\$ (54,260)
General partner's interest	(1,299)	3,344	(955)
Net loss attributable to common limited partners and the general partner	\$ (630,225)	\$ (103,237)	\$ (55,215)
Net loss attributable to common limited partners per unit:			
Basic and Diluted	\$ (8.42)	\$ (2.03)	\$ (1.59)
Weighted average common limited partner units outstanding:			
Basic and Diluted	74,716	52,528	34,039

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in thousands)

	Years Ended December 31,		
	2014	2013	2012
Net loss	\$(610,958)	\$(91,245)	\$(51,902)
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as cash flow hedges, net of \$82.3 million of gains reclassified to impairment expense	153,126	13,852	10,921
Less: reclassification adjustment for realized losses (gains) of cash flow hedges in net loss	7,084	(9,722)	(19,281)
Total other comprehensive income (loss)	160,210	4,130	(8,360)
Comprehensive loss attributable to owner's interest, common and preferred limited partners and the general partner	\$(450,748)	\$(87,115)	\$(60,262)

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

(in thousands, except unit data)

	Preferred Limited Partners' Interest		Class C		Class D		Common Limited Partners' Interests		Class C Common Limited Partner Warrants		Equity
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Amount	
	—	\$—	—	\$—	—	\$—	—	\$—	—	\$—	\$427,2
	—	—	—	—	—	—	—	—	—	—	250
	—	—	—	—	—	—	—	—	—	—	5,625
	—	—	—	—	—	—	26,200,114	424,459	—	—	(433,1
	3,841,719	94,869	—	—	—	—	17,767,874	388,408	—	—	—
	—	—	—	—	—	—	—	10,797	—	—	—
)	—	(1,652)	—	—	—	—	—	(31,545)	—	—	—
—	—	—	—	—	—	—	—	(731)	—	—	—

(5,165)	(125)	—	—	—	—	5,165	125	—	—	—
) —	3,063	—	—	—	—	—	(54,260)	—	—	—
—	—	—	—	—	—	—	—	—	—	—
3,836,554	\$96,155	—	\$—	—	\$—	43,973,153	\$737,253	—	\$—	\$—
—	—	3,749,986	85,448	—	—	15,259,174	320,017	562,497	1,176	—
—	—	—	—	—	—	215,981	12,630	—	—	—
) —	(8,018)	—	(2,100)	—	—	—	(108,923)	—	—	—
—	—	—	—	—	—	—	(1,939)	—	—	—
—	8,402	—	3,590	—	—	—	(106,581)	—	—	—
—	—	—	—	—	—	—	—	—	—	—

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3,836,554	\$96,539	3,749,986	\$86,938	—	\$—	59,448,308	\$852,457	562,497	\$1,176	\$—
—	—	—	—	3,200,000	77,301	21,860,000	426,290	—	—	—
—	—	—	—	—	—	241,733	7,391	—	—	—
) —	(8)	—	(737)	—	(1,974)	—	(16,779)	—	—	—
) —	(9,704)	—	(9,486)	—	—	—	(184,303)	—	—	—
—	—	—	—	—	—	—	(2,158)	—	—	—
(3,796,900)	(94,614)	—	—	—	—	3,796,900	94,614	—	—	—
) —	8,770	—	8,786	—	1,711	—	(628,926)	—	—	—
—	—	—	—	—	—	—	—	—	—	—
) 39,654	\$983	3,749,986	\$85,501	3,200,000	\$77,038	85,346,941	\$548,586	562,497	\$1,176	\$—

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	\$(610,958)	\$(91,245)	\$(51,902)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	233,731	136,763	52,582
Asset impairment	573,774	38,014	9,507
Loss on asset sales and disposal	1,869	987	6,980
Non-cash compensation expense	8,067	12,680	10,828
Amortization of deferred financing costs	9,191	9,560	1,820
Changes in operating assets and liabilities:			
Accounts receivable, prepaid expenses and other	(77,262)	(2,634)	(57,000)
Accounts payable and accrued liabilities	52,011	18,775	43,671
Net cash provided by operating activities	190,423	122,900	16,486
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(212,634)	(263,537)	(127,226)
Net cash paid for acquisitions	(686,811)	(717,795)	(516,670)
Other	3,051	(3,222)	(382)
Net cash used in investing activities	(896,394)	(984,554)	(644,278)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facilities	1,393,000	942,000	667,099
Repayments under credit facilities	(1,116,000)	(874,425)	(315,674)
Net proceeds from issuance of long-term debt	170,596	510,396	—
Net investment from owners	—	—	5,625
Distributions paid to unitholders	(218,995)	(124,932)	(33,875)
Net proceeds from issuance of preferred limited partner units and warrants	77,301	86,624	—
Net proceeds from issuance of common limited partner units	426,290	320,017	290,115
Deferred financing costs, distribution equivalent rights and other	(12,802)	(19,386)	(17,018)
Net cash provided by financing activities	719,390	840,294	596,272
Net change in cash and cash equivalents	13,419	(21,360)	(31,520)
Cash and cash equivalents, beginning of year	1,828	23,188	54,708
Cash and cash equivalents, end of year	\$15,247	\$1,828	\$23,188

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the “Partnership”) is a publicly traded Delaware 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. The Partnership sponsors and manages tax-advantaged investment partnerships (the “Drilling Partnerships”), in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities. At December 31, 2014, Atlas Energy, L.P. (“ATLS”), a publicly traded master-limited partnership (NYSE: ATLS), through a wholly owned subsidiary, owned 100% of the general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 27.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

The Partnership was formed in October 2011 to own and operate substantially all of ATLS’s exploration and production assets (“Atlas Energy E&P Operations”), which were transferred to the Partnership on March 5, 2012. In February 2012, the board of ATLS’s general partner approved the distribution of approximately 5.24 million of the Partnership’s common units which were distributed on March 13, 2012 to ATLS’s unitholders using a ratio of 0.1021 of the Partnership’s limited partner units for each of ATLS’s common units owned on the record date of February 28, 2012.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership’s consolidated balance sheets at December 31, 2014 and 2013, the consolidated statement of operations for the years ended December 31, 2014 and 2013 and the portion of the consolidated statement of operations for the year ended December 31, 2012 subsequent to the transfer of assets on March 5, 2012 include the accounts of the Partnership and its wholly-owned subsidiaries. The portion of the consolidated statement of operations for the year ended December 31, 2012 prior to the transfer of assets on March 5, 2012 was derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if the Partnership had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all of the various entities comprising Atlas E&P Operations prior to the date of transfer, ATLS’s net investment is shown as equity in the consolidated financial statements. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management’s best estimates, in order to derive the financial statements of the Partnership for the periods presented prior to March 5, 2012. Actual balances and results

could be different from those estimates. Transactions between the Partnership and other ATLS operations have been identified in the consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated. Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the current year presentation.

In accordance with established practice in the oil and gas industry, the Partnership's consolidated financial statements include its pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the Drilling Partnerships in which the Partnership has an interest. Such interests generally approximate 30%. The Partnership's consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, the Partnership calculates these items specific to its own economics as further explained under the heading "Property, Plant and Equipment" elsewhere within this note.

Use of Estimates

The preparation of the Partnership's consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership's consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired and liabilities assumed. Such estimates included estimated allocations made from the historical accounting records of ATLS's former owner of its general partner, Atlas Energy, Inc. ("AEI") in order to derive the historical financial statements of the Partnership for periods prior to March 5, 2012. Actual results could differ from those estimates.

Cash Equivalents

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

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. In evaluating the realizability of its accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by management's review of the Partnership's customers' credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At December 31, 2014 and 2013, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had \$8.6 million and \$4.6 million of inventory at December 31, 2014 and 2013, respectively, which was included within prepaid expenses and other current assets on the Partnership's consolidated balance sheets. The Partnership values inventories at the lower of cost or market. The Partnership's inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

Subscriptions Receivable

The Partnership receives contributions from limited partner investors of its Drilling Partnerships, which are used to fund well drilling activities within the programs. Limited partner investors in the Drilling Partnerships execute an investment agreement with Anthem Securities, Inc. ("Anthem"), a registered broker-dealer and wholly owned subsidiary of the Partnership, through third-party broker dealers, which is then delivered to Anthem. The investor contributions are then remitted to Anthem at a later date. Limited partner investor contributions are non-refundable upon the execution of an investment agreement. The Partnership recognizes the contributions associated with the executed investment agreements but for which contributions have not yet been received at the respective balance sheet date as subscriptions receivable.

Property, Plant and Equipment

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

The Partnership follows the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs to enhance or evaluate development of proved fields or areas are capitalized. All other geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil and NGLs are converted to gas equivalent basis ("Mcf") at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

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

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

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

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

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

The Partnership's lower operating and administrative costs result from the limited partners in the Drilling Partnerships paying to the Partnership their proportionate share of these expenses plus a profit margin. These assumptions could result in the Partnership's calculation of depletion and impairment being different than its proportionate share of the Drilling Partnerships' calculations for these items. In addition, reserve estimates for wells with limited or no

production history are less reliable than those based on actual production. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information which could cause the assumptions to be modified. The Partnership cannot predict what reserve revisions may be required in future periods.

The Partnership's method of calculating its reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships, which the Partnership sponsors and owns an interest in but does not control. The Partnership's reserve quantities include reserves in excess of its proportionate share of reserves in Drilling Partnerships, which the Partnership may be unable to recover due to the Drilling Partnerships' legal structure. The Partnership may have to pay additional consideration in the future as a Drilling Partnership's wells become uneconomic to the Drilling Partnership under the terms of the Drilling Partnership's drilling and operating agreement in order to recover these excess reserves, in addition to the Partnership becoming responsible for paying associated future operating, development and plugging costs of the well interests acquired, and to acquire any additional residual interests in the wells held by the Drilling Partnership's limited partners. The acquisition of any such uneconomic well interest from the Drilling Partnership by the Partnership is governed under the Drilling Partnership's limited partner agreement. In general, the Partnership will seek consent from the Drilling Partnership's limited partners to acquire the well interests from the Drilling Partnership based upon the Partnership's determination of fair market value.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. During the year ended December 31, 2013, the Partnership recognized \$13.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet, primarily for its unproved acreage in the Chattanooga and New Albany Shales. There were no impairments of unproved gas and oil properties recorded by the Partnership for the years ended December 31, 2014 and 2012.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2014, the Partnership recognized \$555.7 million of asset impairment related to oil and gas properties within property, plant and equipment, net on its consolidated balance sheet for its Appalachian and mid-continent operations, which was reduced by \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014 through the impairment testing date in January 2015. During the year ended December 31, 2013, the Partnership recognized \$24.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the New Albany Shale. During the year ended December 31, 2012, the Partnership recognized \$9.5 million of asset impairments related to gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara Shales.

These impairments related to the carrying amounts of these gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2014, 2013, and 2012 and management's intention not to drill on certain expiring unproved acreage. The estimate of the fair values of these gas and oil properties was impacted by, among other factors, the deterioration of commodity prices at the date of measurement.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds by the Partnership was 5.6%, 6.0%, and 3.5% for the years ended December 31, 2014, 2013, and 2012, respectively. The aggregate amount of interest capitalized by the Partnership was \$13.0 million, \$14.2 million and \$2.1 million for the years ended December 31, 2014, 2013, and 2012, respectively.

Intangible Assets

The Partnership recorded its intangible assets with finite lives in connection with partnership management and operating contracts acquired through prior consummated acquisitions. The Partnership amortizes contracts acquired on a declining balance method over their respective estimated useful lives.

The following table reflects the components of intangible assets being amortized at December 31, 2014 and 2013 (in thousands):

	December 31,		Estimated
	2014	2013	Useful Lives
			In Years
Gross Carrying Amount	\$14,344	\$14,344	13
Accumulated Amortization	(13,653)	(13,381)	
Net Carrying Amount	\$691	\$963	

Amortization expense on intangible assets was \$0.3 million, \$0.4 million and \$0.2 million for the years ended December 31, 2014, 2013, and 2012, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2015 - \$0.2 million; 2016 - \$0.1 million; 2017 - \$0.1 million; 2018 - \$0.1 million; and 2019 - \$0.1 million.

Goodwill

At December 31, 2014, the Partnership had \$13.6 million of goodwill recorded in connection with its prior consummated acquisitions. At December 31, 2013, the Partnership had \$31.8 million of goodwill recorded in connection with its prior consummated acquisitions.

The Partnership tests goodwill for impairment at each year end by comparing its reporting units' estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership's management must apply judgment in determining the estimated fair value of these reporting units. The Partnership's management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership's assets and the available market data of the industry group. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership's market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership's management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership's industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership's industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise.

As a result of its impairment evaluation at December 31, 2014, the Partnership recognized an \$18.1 million non-cash impairment charge within asset impairments on its consolidated statement of operations for the year ended December 31, 2014. The Partnership's estimated fair value of its gas and oil production reporting unit was impacted by a decline in overall commodity prices during the fourth quarter of 2014. There were no goodwill impairments recognized by the Partnership during the years ended December 31, 2013 and 2012.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates (see Note 9). The derivative instruments recorded in the consolidated balance sheets were measured as either an asset or liability at fair value. Changes in a derivative instrument's fair value are recognized currently in the Partnership's consolidated statements of operations unless specific hedge accounting criteria are met.

Asset Retirement Obligations

The Partnership recognizes an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities (see Note 7). The Partnership recognizes a liability for its future asset retirement obligations in the current period if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

Income Taxes

The Partnership is not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership's taxable income. Such taxable income may vary substantially from net income reported in the accompanying consolidated financial statements. Certain corporate subsidiaries of the Partnership are subject to federal and state income tax. The federal and state income taxes related to the Partnership and these corporate subsidiaries were immaterial to the consolidated financial statements and are recorded in pre-tax income on a current basis only. Accordingly, no federal or state deferred income tax has been provided for in the accompanying consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the years ended December 31, 2014, 2013, and 2012.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2011. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of December 31, 2014.

Stock-Based Compensation

The Partnership recognizes all share-based payments to employees, including grants of employee stock options, in the consolidated financial statements based on their fair values (see Note 15).

Net Income (Loss) Per Common Unit

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

Prior to the transfer of assets to the Partnership on March 5, 2012 (see Note 1), the Partnership had no common units or General Partner Class A units outstanding. In addition, the Partnership had no net income (loss) attributable to common limited partners and the general partner prior to March 5, 2012.

The Partnership presents net income (loss) per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights' share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management of the Partnership believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. Phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plan (see Note 15), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights would result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award's vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. As such, the net income utilized in the calculation of net income (loss) per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net loss allocated to the common limited partners for purposes of calculating net loss attributable to common limited partners per unit (in thousands, except unit data):

	Years Ended December 31,		
	2014	2013	2012
Net loss	\$(610,958)	\$(91,245)	\$(51,902)
Income applicable to owner's interest (period prior to transfer of assets on March 5, 2012)	—	—	(250)
Preferred limited partner dividends	(19,267)	(11,992)	(3,063)
Net loss attributable to common limited partners and the general partner	(630,225)	(103,237)	(55,215)
Less: General partner's interest	1,299	(3,344)	955
Net loss attributable to common limited partners	(628,926)	(106,581)	(54,260)
Less: Net income attributable to participating securities – phantom units ⁽⁴⁾	—	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit	\$(628,926)	\$(106,581)	\$(54,260)

(1) Net income attributable to common limited partners' ownership interests is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the years ended December 31, 2014, 2013, and 2012, net loss attributable to common limited partners' ownership interest is not allocated to approximately 783,000, 900,000, and 688,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, convertible preferred units and warrants, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership's long-term incentive plan (see Note 15).

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

	Years Ended December 31,		
	2014	2013	2012
Weighted average number of common limited partner units - basic	74,716	52,528	34,039
Add effect of dilutive incentive awards ⁽¹⁾	—	—	—

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Add effect of dilutive convertible preferred limited partner units and warrants ⁽²⁾	—	—	—
Weighted average number of common limited partner units - diluted	74,716	52,528	34,039

(1) For the years ended December 31, 2014, 2013, and 2012, approximately 783,000 units, 900,000 units, and 688,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

(2) For the years ended December 31, 2014, 2013, and 2012, potential common limited partner units issuable upon conversion of the Partnership's Class B preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive.

For the years ended December 31, 2014 and 2013, potential common limited partner units issuable upon (a) conversion of the Partnership's Class C preferred units and (b) exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As the Class D preferred units are convertible only upon a change of control event, they are not considered dilutive securities for earnings per unit purposes.

Environmental Matters

The Partnership and its subsidiaries are subject to various federal, state and local laws and regulations relating to the protection of the environment. Management has established procedures for the ongoing evaluation of the Partnership's and its subsidiaries' operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. The Partnership and its subsidiaries maintain insurance which may cover in whole or in part certain environmental expenditures. The Partnership and its subsidiaries had no environmental matters requiring specific disclosure or requiring the recognition of a liability for the years ended December 31, 2014 and 2013. During the year ended December 31, 2012, one of the Partnership's subsidiaries entered into two agreements with the United States Environmental Protection Agency (the "EPA") to settle alleged violations in connection with a fire that occurred at a natural gas well and associated well pad site in Washington County, Pennsylvania in 2010. The EPA alleged non-compliance with the Clean Air Act, including with respect to the storage and handling of the natural gas condensate, as well as non-compliance with the Emergency Planning and Community Right-to-Know Act of 1986. The subsidiary agreed to a civil penalty of \$84,506 under a consent agreement and agreed to upgrade its facility pursuant to an administrative settlement agreement.

Concentration of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist principally of periodic temporary investments of cash and cash equivalents. The Partnership places its temporary cash investments in high-quality short-term money market instruments and deposits with high-quality financial institutions and brokerage firms. At December 31, 2014 and 2013, the Partnership had \$17.2 million and \$15.1 million, respectively, in deposits at various banks, of which \$14.9 million and \$13.4 million, respectively, were over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments to date.

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

The Partnership sells natural gas, crude oil and NGLs under contracts to various purchasers in the normal course of business. For the year ended December 31, 2014, the Partnership had four customers within its gas and oil production segment that individually accounted for approximately 25%, 15%, 14% and 13%, respectively, of the Partnership natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2013, the Partnership had three customers within its gas and oil production segment that individually accounted for approximately 19%, 11% and 10% of the Partnership's natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2012, the Partnership had two customers within its gas and oil production segment that individually accounted for

approximately 43% and 11% of the Partnership's natural gas, oil and NGL consolidated revenues, excluding the impact of all financial derivative activity.

Revenue Recognition

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

Drilling Partnerships. Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by the Partnership is deployed to drill and complete wells included within the partnership. As the Partnership deploys Drilling Partnership investor capital, it recognizes certain management fees it is entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if the Partnership has Drilling Partnership investor capital that has not yet been deployed, it will recognize a current liability titled "Liabilities Associated with Drilling Contracts" on the Partnership's consolidated balance sheets. After the Drilling Partnership well is completed and turned in line, the Partnership is 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 it is entitled to receive for services provided, the Partnership is also entitled to its pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%. The Partnership recognizes its Drilling Partnership management fees in the following manner:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, the Partnership receives a 15% mark-up on those costs incurred to drill and complete 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, the Partnership receives 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 the Partnership a monthly per well administrative fee of \$75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed.
- Well services. Each Drilling Partnership pay the Partnership a monthly per well operating fee, currently \$1,000 to \$2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed.

While its historical structure has varied, the Partnership has generally agreed to subordinate a portion of its 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. The Partnership periodically compares 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, the Partnership recognizes subordination as an estimated reduction of its 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 the Partnership has 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, the Partnership will recognize an estimated increase in its portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

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

The Partnership's gas and oil production operations accrue unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see "Use of Estimates" for further description). The Partnership had unbilled revenues at December 31, 2014 and 2013 of \$82.3 million and \$55.3 million, respectively, which were included in accounts receivable within the Partnership's consolidated balance sheets.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as “other comprehensive income (loss)” on the Partnership’s consolidated financial statements, and for all periods presented, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 9). The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss).

Recently Adopted Accounting Standards

In November 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-17, Business Combinations (Topic 805) – Pushdown Accounting (“Update 2014-17”). The amendments in Update 2014-17 provide an acquired entity with an option to apply pushdown accounting in its separate financial statements upon occurrence of an event in which an acquirer obtains control of the acquired entity. The amendments in Update 2014-17 also provide U.S. GAAP guidance on whether and at what threshold an acquired entity that is a business can apply pushdown accounting in its separate financial statements. The amendments in Update 2014-17 became effective on November 18, 2014. After the effective date, an acquired entity can make an election to apply the guidance to future change-in-control events or to its most recent change-in-control event. However, if the financial statements for the period in which the most recent change-in-control event occurred already have been issued or made available to be issued, the application of this guidance would be a change in accounting principle. The Partnership adopted the requirements of Update 2014-17 upon its effective date of November 18, 2014, and it had no material impact on its financial position, results of operations or related disclosures.

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) – Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (“Update 2013-11”), which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption was permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application was permitted. The Partnership adopted the requirements of Update 2013-11 upon its effective date of January 1, 2014, and it had no material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (“Update 2013-04”). Update 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements, for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations and settled litigation and judicial rulings. Update 2013-04 requires an entity to measure joint and several liability arrangements, for which the total amount of the obligation is fixed at the reporting date as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, Update 2013-04 provides disclosure guidance on the nature and amount of the obligation as well as other information. Update 2013-04 is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. The Partnership adopted the requirements of Update 2013-04 upon its effective date of January 1, 2014, and it had no material impact on its financial position, results of operations or related disclosures.

Recently Issued Accounting Standards

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis (“Update 2015-02”). The amendments in Update 2015-02 are intended to improve targeted areas of consolidation guidance for legal entities such as limited partnerships, limited liability corporations and securitization structures. The amendments simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. The amendments in Update 2015-02 are effective for periods beginning after December 31, 2015. Early adoption is permitted, including adoption in an interim period. The Partnership will adopt the requirements of Update 2015-02 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In January 2015, the FASB issued ASU 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items (“Update 2015-01”). The amendments in Update 2015-01 simplify the income statement presentation requirements in Subtopic 225-20 by eliminating the concept of extraordinary items. Extraordinary items are events and transactions that are distinguished by their unusual nature and by the infrequency of their occurrence. Eliminating the extraordinary classification simplifies income statement presentation by altogether removing the concept of extraordinary items from consideration. The amendments in Update 2015-01 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. A reporting entity may apply the amendments prospectively. A reporting entity may also apply the amendments retrospectively to all prior periods presented in the financial statements. Early adoption is permitted provided that the guidance is applied from the beginning of the fiscal year of adoption. The Partnership will adopt the requirements of Update 2015-01 upon its effective date of January 1, 2016, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In November 2014, the FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815) – Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity (“Update 2014-16”). Certain classes of shares include features that entitle the holders to preferences and rights (such as conversion rights, redemption rights, voting powers, and liquidation and dividend payment preferences) over the other shareholders. Shares that include embedded derivative features are referred to as hybrid financial instruments, which must be separated from the host contract and accounted for as a derivative if certain criteria are met under Subtopic 815-10. One criterion requires evaluating whether the nature of the host contract is more akin to debt or to equity and whether the economic characteristics and risks of the embedded derivative feature are “clearly and closely related” to the host contract. In making that evaluation, an issuer or investor may consider all terms and features in a hybrid financial instrument including the embedded derivative feature that is being evaluated for separate accounting or may consider all terms and features in the hybrid financial instrument except for the embedded derivative feature that is being evaluated for separate accounting. The use of different methods can result in different accounting outcomes for economically similar hybrid financial instruments. Additionally, there is diversity in practice with respect to the consideration of redemption features in relation to other features when determining whether the nature of a host contract is more akin to debt or to equity. The amendments in Update 2014-16 clarify how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. The effects of initially adopting the amendments in Update 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in the form of a share as of the

beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. The amendments in Update 2014-16 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption, including adoption in an interim period, is permitted. The Partnership will adopt the requirements of Update 2014-16 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40) (“Update 2014-15”). The amendments in Update 2014-15 provide U.S. GAAP guidance on the responsibility of an entity’s management in evaluating whether there is substantial doubt about the entity’s ability to continue as a going concern and about related footnote disclosures. For each reporting period, an entity’s management will be required to evaluate whether there are conditions or events that raise substantial doubt about its ability to continue as a going concern within one year from the date the financial statements are issued. In doing so, the amendments in Update 2014-15 should reduce diversity in the timing and content of footnote disclosures. The amendments in Update 2014-15 are effective for the annual period ending after December 15, 2016, and for annual and interim periods thereafter. Early adoption is permitted. The Partnership will adopt the requirements of Update 2014-15 upon its effective date of January 1, 2017, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In June 2014, the FASB issued ASU 2014-12, Compensation – Stock Compensation (Topic 718) (“Update 2014-12”). The amendments in Update 2014-12 require that a performance target that affects vesting and that could be achieved after the requisite service period, be treated as a performance condition. As such, the performance target should not be reflected in estimating the grant date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. The amendments in Update 2014-12 are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Earlier adoption is permitted. Entities may apply the amendments in Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The Partnership will adopt the requirements of Update 2014-12 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) (“Update 2014-09”), which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, Property, Plant and Equipment, and intangible assets within the scope of Topic 350, Intangibles – Goodwill and Other) are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The Partnership will adopt the requirements of Update 2014-09 retrospectively upon its effective date of January 1, 2017, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

NOTE 3 – ATLAS ENERGY, L.P. ACQUISITION FROM ATLAS ENERGY, INC.

On February 17, 2011, ATLS acquired certain producing natural gas and oil properties, the partnership management business and other assets (the “Transferred Business”) from AEI, including the following exploration and production assets that were transferred to the Partnership on March 5, 2012:

- AEI's investment management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which the Partnership funds a portion of its natural gas and oil well drilling;
- proved reserves located in the Appalachian Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan and the Chattanooga Shale of northeastern Tennessee; and
- certain producing natural gas and oil properties, upon which the Partnership is the developer and producer.

Concurrent with ATLS's acquisition of the Transferred Business, AEI was sold to Chevron Corporation (NYSE: CVX; "Chevron"). In connection with the transaction, ATLS received \$118.7 million with respect to a contractual cash transaction adjustment from AEI related to certain exploration and production liabilities assumed by ATLS. Including the cash transaction adjustment, the net book value of the Transferred Business was approximately \$522.9 million. Certain amounts included within the contractual cash transaction adjustment were subject to a reconciliation period with Chevron following the consummation of the transaction. Liabilities related to the cash transaction adjustment were assumed by the Partnership on March 5, 2012, as certain amounts included within the contractual cash transaction adjustment remained in dispute between the parties. During the year ended December 31, 2012, the Partnership recognized a \$7.7 million charge on its consolidated statement of operations regarding its reconciliation process with Chevron, which was settled in October 2012.

Management of ATLS determined that the acquisition of the Transferred Business constituted a transaction between entities under common control. As such, ATLS recognized the assets acquired and liabilities assumed at historical carrying value at the date of acquisition, with the difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital on its consolidated combined balance sheet. ATLS recognized a non-cash decrease of \$261.0 million in partners' capital on its consolidated combined balance sheet based on the excess net book value above the value of the consideration paid to AEI. The following table presents the historical carrying values of the assets acquired and liabilities assumed by ATLS, including the effect of cash transaction adjustments, as of February 17, 2011 (in thousands):

Cash	\$ 153,350
Accounts receivable	18,090
Accounts receivable – affiliate	45,682
Prepaid expenses and other	6,955
Total current assets	224,077
Property, plant and equipment, net	516,625
Goodwill	31,784
Intangible assets, net	2,107
Other assets, net	20,416
Total long-term assets	570,932
Total assets acquired	\$ 795,009
Accounts payable	\$ 59,202
Net liabilities associated with drilling contracts	47,929
Accrued well completion costs	39,552
Current portion of derivative payable to Drilling Partnerships	25,659
Accrued liabilities	25,283
Total current liabilities	197,625
Long-term derivative payable to Drilling Partnerships	31,719
Asset retirement obligations	42,791
Total long-term liabilities	74,510
Total liabilities assumed	\$ 272,135
Historical carrying value of net assets acquired	\$ 522,874

The Partnership reflected the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which the Transferred Business was acquired.

NOTE 4 – ACQUISITIONS

Rangely Acquisition

On June 30, 2014, the Partnership completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado from Merit Management Partners I, L.P., Merit Energy Partners III, L.P. and Merit Energy Company, LLC (collectively, "Merit Energy") for approximately \$409.4 million in cash, net of purchase price adjustments (the "Rangely Acquisition"). The purchase price was funded through borrowings under the Partnership's revolving credit facility, the issuance of an additional \$100.0 million of its 7.75% senior notes due 2021 ("7.75% Senior Notes") (see Note 8) and the issuance of 15,525,000 common limited partner units (see Note 13). The Rangely Acquisition had an effective date of April 1, 2014. The Partnership's consolidated financial statements reflected the operating results of the acquired business commencing June 30, 2014 with the transaction closing.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 10). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded \$11.6 million of transaction fees, which were included with common limited partners' interests for the year ended December 31, 2014 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

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Assets:	
Prepaid expenses and other	\$4,041
Property, plant and equipment	405,876
Other assets, net	2,888
Total assets acquired	\$412,805
Liabilities:	
Accrued liabilities	2,117
Asset retirement obligation	1,305
Total liabilities assumed	3,422
Net assets acquired	\$409,383

Revenues and net income of \$41.5 million and \$18.8 million, respectively, have been included in the Partnership's consolidated statement of operations related to the Rangely Acquisition for the year ended December 31, 2014.

EP Energy Acquisition

On July 31, 2013, the Partnership completed an acquisition of assets from EP Energy E&P Company, L.P. ("EP Energy") for approximately \$709.6 million in cash, net of purchase price adjustments (the "EP Energy Acquisition"). The purchase price was funded through borrowings under the Partnership's revolving credit facility, the issuance of the Partnership's 9.25% senior notes due August 15, 2021 ("9.25% Senior Notes") (see Note 8), and the issuance of 14,950,000 common limited partner units and 3,749,986 newly created Class C convertible preferred units (see Note 13). The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013. The Partnership's consolidated financial statements reflected the operating results of the acquired business commencing July 31, 2013 with the transaction closing.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 10). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded \$12.1 million of transaction fees which were included within common limited partners' interests for the year ended December 31, 2013 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

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

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Assets:

Prepaid expenses and other	\$5,268
Property, plant and equipment	723,842
Total assets acquired	\$729,110

Liabilities:

Accounts payable	2,747
Asset retirement obligation	16,728
Total liabilities assumed	19,475
Net assets acquired	\$709,635

DTE Acquisition

On December 20, 2012, the Partnership completed the acquisition of DTE Gas Resources, LLC from DTE Energy Company (NYSE: DTE; "DTE") for \$257.4 million (the "DTE Acquisition"). In connection with entering into a purchase agreement related to the DTE Acquisition, the Partnership issued approximately 7.9 million of its common limited partner units through a public offering in November 2012 for \$174.5 million, which was used to partially repay amounts outstanding under its revolving credit facility prior to closing (see Note 13). The cash paid at closing was funded through \$179.8 million of borrowings under the Partnership's revolving credit facility and \$77.6 million through borrowings under its then-existing term loan credit facility (see Note 8).

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 10). In conjunction with the issuance of common units associated with the acquisition, the Partnership recorded \$0.2 million of transaction fees within common limited partners' interests for the year ended December 31, 2012 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

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

Assets:	
Accounts receivable	\$10,721
Prepaid expenses and other	2,100
Total current assets	12,821
Property, plant and equipment	263,194
Other assets, net	273
Total assets acquired	\$276,288
Liabilities:	
Accounts payable	\$7,760
Accrued liabilities	2,910
Total current liabilities	10,670
Asset retirement obligation and other	8,169
Total liabilities assumed	18,839

Net assets acquired \$257,449

Titan Acquisition

On July 25, 2012, the Partnership completed the acquisition of Titan Operating, L.L.C. (“Titan”) in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had an estimated collective value of \$193.2 million, based upon the closing price of the Partnership’s publicly traded units as of the acquisition closing date), as well as \$15.4 million in cash for closing adjustments (see Note 13). The cash paid at closing was funded through borrowings under the Partnership’s credit facility. The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the “Securities Act”) (see Note 13). The Partnership’s acquisition of Titan in exchange for 3.8 million common units and 3.8 million newly created convertible Class B preferred units represented a non-cash transaction during the year ended December 31, 2012.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 10). In conjunction with the issuance of common and preferred limited partner units associated with the acquisition, the Partnership recorded \$3.5 million of transaction fees within common and preferred limited partners’ interests for the year ended December 31, 2012 on the Partnership’s consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

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

Assets:	
Cash and cash equivalents	\$372
Accounts receivable	5,253
Prepaid expenses and other	131
Total current assets	5,756
Property, plant and equipment	208,491
Other assets, net	2,344
Total assets acquired	\$216,591
Liabilities:	
Accounts payable	\$676
Revenue distribution payable	3,091
Accrued liabilities	1,816
Total current liabilities	5,583
Asset retirement obligation and other	2,418
Total liabilities assumed	8,001
Net assets acquired	\$208,590

Carrizo Acquisition

On April 30, 2012, the Partnership completed the acquisition of certain oil and natural gas assets from Carrizo Oil and Gas, Inc. (NASDAQ: CRZO; “Carrizo”) for approximately \$187.0 million in cash (the “Carrizo Acquisition”). The purchase price was funded through borrowings under the Partnership’s credit facility and \$119.5 million of net proceeds from the sale of 6.0 million of its common units at a negotiated purchase price per unit of \$20.00, of which \$5.0 million was purchased by certain executives of the Partnership. The common units were issued in a private transaction exempt from registration under the Securities Act (see Note 13). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded \$1.2 million of transaction fees within common limited partners’ interests for the year ended December 31, 2012 on the Partnership’s consolidated balance sheet.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 10).

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

Assets:	
Property, plant and equipment	\$ 190,946
Liabilities:	
Asset retirement obligation	3,903
Net assets acquired	\$ 187,043

Pro Forma Financial Information

The following data presents pro forma revenues, net income (loss) and basic and diluted net income (loss) per unit for the Partnership as if the Rangely and EP Energy acquisitions, including the related borrowings, net proceeds from the issuance of debt and issuances of common and preferred units had occurred on January 1, 2013. The Partnership prepared these pro forma unaudited financial results for comparative purposes only; they may not be indicative of the results that would have occurred if the Rangely and EP Energy acquisitions and related offerings had occurred on January 1, 2013 or the results that will be attained in future periods (in thousands, except per unit data; unaudited):

	Years Ended	
	December 31,	
	2014	2013
Total revenues and other	\$731,561	\$649,856
Net loss	(592,693)	(22,084)
Net loss attributable to common limited partners	(592,145)	(27,051)
Net loss attributable to common limited partners per unit:		
Basic and Diluted	\$(7.33)	\$(0.33)

Other Acquisitions

On November 5, 2014, the Partnership and ATLS's development subsidiary (the "Development Subsidiary") completed an acquisition of oil and natural gas liquid interests in the Eagle Ford Shale in Atascosa County, Texas from Cima Resources, LLC and Cinco Resources, Inc. (together "Cinco") for \$339.2 million, net of purchase price adjustments (the "Eagle Ford Acquisition"). Approximately \$179.5 million was paid in cash by the Partnership and \$19.7 million was paid by the Development Subsidiary at closing, and approximately \$140.0 million will be paid over the four quarters following closing. The deferred portion of the purchase price represents a non-cash transaction for statement of cash flow purposes during the year ended December 31, 2014. The Partnership will pay approximately \$24.0 million of the deferred portion of the purchase price in three quarterly installments beginning March 31, 2015. The Development Subsidiary will pay approximately \$116.0 million of the deferred portion purchase price in four quarterly installments following closing. The Partnership may pay up to \$20.0 million of its deferred portion of the purchase price by issuing its 8.625% Class D cumulative redeemable perpetual preferred units ("Class D Preferred Units") at a price of \$25.00 per unit (see Note 13). ARP recognized \$2.8 million of gains on mark-to-market derivatives within other, net on the Partnership's consolidated statement of operations for the year ended December 31, 2014 in connection with entering into derivative instruments upon signing the Eagle Ford Acquisition. In connection with the closing of the Eagle Ford Acquisition, the Partnership's revolving credit facility was amended to increase the borrowing base to \$900.0 million and to make certain amendments to allow for the deferred purchase payments (see Note 8). The Eagle Ford Acquisition had an effective date of July 1, 2014.

On May 12, 2014, the Partnership completed the acquisition of certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for approximately \$97.9 million in cash, net of purchase price adjustments, with an effective date of January

1, 2014. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

On September 20, 2013, the Partnership completed the acquisition of certain assets from Norwood Natural Resources (“Norwood”) for \$5.4 million (the “Norwood Acquisition”). The assets acquired included Norwood’s non-operating working interest in certain producing wells in the Barnett Shale. The Norwood Acquisition had an effective date of June 1, 2013.

In April 2012, the Partnership acquired a 50% interest in approximately 14,500 net undeveloped acres in the oil and NGL area of the Mississippi Lime play in northwestern Oklahoma for \$18.0 million from subsidiaries of Equal Energy, Ltd. (NYSE: EQU; TSX: EQU; “Equal”). The transaction was funded through borrowings under the Partnership’s revolving credit facility. Concurrent with the purchase of acreage, the Partnership and Equal entered into a participation and development agreement for future drilling in the Mississippi Lime play. The Partnership served as the drilling and completion operator, while Equal undertook production operations, including water disposal. In September 2012, the Partnership acquired Equal’s remaining 50% interest in the undeveloped acres, as well as approximately 8 MMcfed of net production in the Mississippi Lime region and salt water disposal infrastructure for \$41.3 million, including \$1.3 million related to certain post-closing adjustments. Both transactions were financed through borrowings under the Partnership’s revolving credit facility. As a result of the Partnership’s acquisition of Equal’s remaining interest in the undeveloped acres, the existing joint venture agreement between the Partnership and Equal in the Mississippi Lime position was terminated and all infrastructure associated with the assets, principally the salt water disposal system, is operated by the Partnership.

NOTE 5 – PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment at the dates indicated (in thousands):

	December 31,		Estimated
	2014	2013	Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	\$441,548	\$320,459	
Pre-development costs	7,223	4,367	
Wells and related equipment	2,962,202	2,164,760	
Total proved properties	3,410,973	2,489,586	
Unproved properties	217,174	211,536	
Support equipment	37,062	23,005	
Total natural gas and oil properties	3,665,209	2,724,127	
Pipelines, processing and compression facilities	49,462	42,949	2 – 40
Rights of way	830	830	20 – 40
Land, buildings and improvements	9,160	9,462	3 – 40
Other	17,932	15,318	3 – 10
	3,742,593	2,792,686	
Less – accumulated depreciation, depletion and amortization	(1,534,422)	(671,868)	
	\$2,208,171	\$2,120,818	

During the year ended December 31, 2014, the Partnership recognized \$1.9 million of loss on asset disposal, primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement. During the year ended December 31, 2013, the Partnership recognized \$1.0 million of loss on asset disposal, primarily pertaining to the loss on the sale of its Antrim assets. During the year ended December 31, 2012, the Partnership recognized a \$7.0 million loss on asset disposal, pertaining to its decision to terminate a farm out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm out agreement contained certain well drilling targets for the Partnership to maintain ownership of the South Knox processing plant, which the Partnership's management decided in 2012 not to achieve due to the then current natural gas price environment. As a result, the Partnership's management forfeited its interest in the processing plant and related properties and recorded a loss related to the net book values of those assets during the year ended December 31, 2012.

During the year ended December 31, 2014, the Partnership recognized \$555.7 million of asset impairment related to oil and gas properties within property, plant and equipment, net on its consolidated balance sheet for its Appalachian and mid-continent operations, which was reduced by \$82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014 through the impairment testing date in January 2015. During the year ended December 31, 2013, the Partnership recognized \$38.0 million of

asset impairments related to its oil and gas properties within property, plant and equipment, net on its consolidated balance sheet primarily for its shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. During the year ended December 31, 2012, the Partnership recognized \$9.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2014, 2013 and 2012 and management's intention not to drill on certain expiring unproved acreage. The estimates of fair values of these gas and oil properties were impacted by, among other factors, the deterioration of commodity prices at the date of measurement.

During the years ended December 31, 2014 and 2013, the Partnership recognized \$25.0 million and \$26.0 million, respectively, of non-cash property, plant and equipment additions, which were included within the changes in accounts payable and accrued liabilities on the Partnership's consolidated statements of cash flows.

NOTE 6 – OTHER ASSETS

The following is a summary of other assets at the dates indicated (in thousands):

	December 31,	
	2014	2013
Deferred financing costs, net of accumulated amortization of \$21,139 and \$11,948 at December 31, 2014 and 2013, respectively	\$40,637	\$35,292
Notes receivable	3,866	3,978
Other	5,578	3,551
	\$50,081	\$42,821

Deferred financing costs are recorded at cost and amortized over the term of the respective debt agreements (see Note 8). Amortization expense of deferred financing costs was \$8.6 million, \$6.4 million and \$1.8 million for the years ended December 31, 2014, 2013 and 2012, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the year ended December 31, 2014, the Partnership recognized \$0.6 million for accelerated amortization of deferred financing costs associated with a reduction of the borrowing base under the revolving credit facility. During the year ended December 31, 2013, the Partnership also recognized \$3.2 million for accelerated amortization of deferred financing costs associated with the retirement of its then-existing term loan facility and a portion of the outstanding indebtedness under its revolving credit facility with a portion of the proceeds from its issuance of its 7.75% Senior Notes (see Note 8). There was no accelerated amortization of deferred financing costs during the year ended December 31, 2012.

At December 31, 2014 and 2013, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership's consolidated balance sheets. The notes have a maturity date of March 31, 2022, and a 2.25% per annum interest rate. The maturity date of the notes can be extended to March 31, 2027, subject to certain conditions, including an extension fee of 1.0% of the outstanding principal balance. For each of the years ended December 31, 2014 and 2013, \$0.1 million of interest income was recognized within other, net on the Partnership's consolidated statements of operations. There was no interest income recognized for the year ended December 31, 2012. At December 31, 2014 and 2013, the Partnership recorded no allowance for credit losses within its consolidated balance sheets based upon payment history and ongoing credit evaluations associated with the notes receivable.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

The Partnership recognized an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities. The Partnership also recognized a liability for its future asset retirement obligations where a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability for asset retirement obligations was based on the Partnership's historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future, and federal and state regulatory requirements. The liability was discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. The Partnership has no assets legally restricted for purposes of settling asset retirement obligations. Except for its gas and oil properties, the Partnership determined that there were no other material retirement obligations associated with tangible long-lived assets.

The Partnership proportionately consolidates its ownership interest of the asset retirement obligations of its Drilling Partnerships. At December 31, 2014, the Drilling Partnerships had \$47.6 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of the Partnership's proportional interest in such liabilities. Under the terms of the respective partnership agreements, the Partnership maintains the right to retain a portion or all of the distributions to the limited partners of its Drilling Partnerships to cover the limited partners' share of the plugging and abandonment costs up to a specified amount per month. As of December 31, 2014, the Partnership has withheld \$1.6 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. The Partnership's historical practice and continued intention is to retain distributions from the limited partners as the wells within each Drilling Partnership near the end of their useful life. On a partnership-by-partnership basis, the Partnership assesses its right to withhold amounts related to plugging and abandonment costs based on several factors including commodity price trends, the natural decline in the production of the wells, and current and future costs. Generally, the Partnership's intention is to retain distributions from the limited partners as the fair value of the future cash flows of the limited partners' interest approaches the fair value of the future plugging and abandonment cost. Upon the Partnership's decision to retain all future distributions to the limited partners of its Drilling Partnerships, the Partnership will assume the related asset retirement obligations of the limited partners.

A reconciliation of the Partnership's liability for well plugging and abandonment costs for the periods indicated is as follows (in thousands):

	Years Ending December 31,		
	2014	2013	2012
Asset retirement obligations, beginning of year	\$89,776	\$64,794	\$45,779
Liabilities incurred	10,509	21,786	16,568
Liabilities settled	(1,532)	(1,188)	(546)
Accretion expense	5,645	4,384	2,993
Revisions	2,130	—	—
Asset retirement obligations, end of year	\$106,528	\$89,776	\$64,794

The above accretion expense was included in depreciation, depletion and amortization in the Partnership's consolidated statements of operations. During the years ended December 31, 2014, 2013, and 2012, the Partnership incurred \$7.0 million, \$16.7 million, and \$15.6 million, respectively, of future plugging and abandonment costs related to acquisitions it consummated (see Note 4).

NOTE 8 - DEBT

Total debt consists of the following at the dates indicated (in thousands):

	December 31,	
	2014	2013
Revolving credit facility	\$696,000	\$419,000
7.75 % Senior Notes – due 2021	374,544	275,000
9.25 % Senior Notes – due 2021	323,916	248,334
Total debt	1,394,460	942,334
Less current maturities	—	—
Total long-term debt	\$1,394,460	\$942,334

Credit Facility

On November 24, 2014, the Partnership entered into a Fifth Amendment to its Second Amended and Restated Credit Agreement dated July 31, 2013 with Wells Fargo Bank National Association, as administrative agent, and the lenders party thereto, among the Partnership as borrower, the administrative agent and the lenders party thereto (the “Credit Agreement”). The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a current borrowing base of \$900.0 million and a maximum facility amount of \$1.5 billion scheduled to mature in July 2018.

The Fifth Amendment was entered into in connection with the previously announced restructuring of the Partnership’s general partner and the sale of ATLS and its midstream assets (see Note 17). Among other things, the Fifth Amendment amended several definitions for the purpose of ensuring that the sale does not result in a Change of Control or Event of Default as defined in the Credit Agreement.

On September 24, 2014, in connection with its Eagle Ford Acquisition (see Note 4), the Partnership entered into a fourth amendment to the Credit Agreement. In connection with the closing of the Eagle Ford Acquisition, the borrowing base under the Partnership's revolving credit facility was increased from \$825.0 million to \$900.0 million. The fourth amendment amended the Credit Agreement to permit the guarantee by the Partnership of certain deferred purchase price obligations and contingent indemnity obligations in connection with the Eagle Ford Acquisition, and, with certain constraints, to permit the Partnership and its subsidiaries to enter into certain derivative instruments related to the producing wells to be acquired in the Eagle Ford Acquisition.

On June 30, 2014, in connection with the Rangely Acquisition (see Note 4), the Partnership entered into a third amendment to the Credit Agreement. Among other things, pursuant to the third amendment:

- the borrowing base was increased to \$825.0 million;

- if the borrowing base utilization is less than 25%, the Partnership will incur the applicable margin on Eurodollar loans of 1.50%, the applicable margin on alternative base rate loans of 0.50% and a commitment fee rate of 0.375%; and

- the maximum ratio of Total Funded Debt to EBITDA was revised to be (i) 4.50 to 1.0 as of the last day of the quarters ended on June 30, 2014, September 30, 2014 and December 31, 2014, (ii) 4.25 to 1.0 as of the last day of the quarter ending on March 31, 2015 and (iii) 4.00 to 1.0 as of the last day of each quarter thereafter.

The Partnership's borrowing base is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. At December 31, 2014, \$696.0 million was outstanding under the credit facility. Up to \$20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which \$4.4 million was outstanding at December 31, 2014. The Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by certain of the Partnership's material subsidiaries, and any non-guarantor subsidiaries of the Partnership are minor. Borrowings under the credit facility bear interest, at the Partnership's election, at either an adjusted LIBOR rate plus an applicable margin between 1.50% and 2.75% per annum or the base rate (which is the higher of the bank's prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 0.50% and 1.75% per annum. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At December 31, 2014, the weighted average interest rate on outstanding borrowings under the credit facility was 2.9%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default

exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of December 31, 2014. The Credit Agreement also requires the Partnership to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended on June 30, 2014, September 30, 2014 and December 31, 2014, 4.25 to 1.0 as of the last day of the quarter ending March 31, 2015, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. Based on the definitions contained in the Partnership's Credit Agreement, at December 31, 2014, the Partnership's ratio of current assets to current liabilities was 1.2 to 1.0, and its ratio of Total Funded Debt to EBITDA was 3.6 to 1.0.

On February 23, 2015, the Partnership entered into a Sixth Amendment to the Credit Agreement (the "Sixth Amendment") and a Second Lien Credit Agreement (the "Second Lien Credit Agreement") (see Note 17).

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Senior Notes

At December 31, 2014, the Partnership had \$374.5 million outstanding of its 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"), including \$100.0 million of such notes issued in a private placement transaction on June 2, 2014 at an offering price of 99.5% of par value, yielding net proceeds of approximately \$97.4 million. The net proceeds were used to partially fund the Rangely Acquisition (see Note 4). The 7.75% Senior Notes were presented net of a \$0.5 million unamortized discount as of December 31, 2014. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019.

The Partnership entered into registration rights agreements with respect to its 7.75% Senior Notes. Under the registration rights agreements, the Partnership agreed to (a) file exchange offer registration statements with the SEC to exchange the privately issued notes for registered notes, (b) cause the exchange offer for the \$275.0 million of 7.75% Senior Notes issued on January 23, 2013 to be consummated not later than 365 days after the issuance of such notes and (c) cause the exchange offer for the \$100.0 million of 7.75% Senior Notes issued on June 2, 2014 to be consummated not later than 270 days after the issuance of such notes. A registration statement relating to the exchange offer for the \$275.0 million of 7.75% Senior Notes issued January 23, 2013 was declared effective on December 2, 2013, and the exchange offer for such notes was completed on January 2, 2014. A registration statement relating to the exchange offer for the \$100.0 million of 7.75% Senior Notes issued June 2, 2014 was declared effective on October 17, 2014 and the exchange offer for such notes was completed on November 18, 2014.

At December 31, 2014, the Partnership had \$323.9 million outstanding of its 9.25% senior unsecured notes due 2021 ("9.25% Senior Notes"), including \$75.0 million of such notes issued in a private placement transaction on October 14, 2014 at an offering price of 100.5% of par value, which yielded net proceeds of approximately \$73.6 million. The 9.25% Senior Notes issued in October 2014 were presented net of a \$0.4 million unamortized premium as of December 31, 2014. The 9.25% Senior Notes issued in July 2013 were presented net of a \$1.5 million unamortized discount as of December 31, 2014. The Partnership used the net proceeds from this offering to fund a portion of its Eagle Ford Acquisition (see Note 4). Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time on or after August 15, 2017, the Partnership may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, the Partnership may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of

changes of control, the Partnership must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the \$75.0 million of 9.25% Senior Notes on October 14, 2014, the Partnership entered into a registration rights agreement whereby the Partnership agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (“SEC”) to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated not later than 270 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, the Partnership has agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If the Partnership fails to comply with its obligations to register the 9.25% Senior Notes within the specified time periods, the Partnership will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable.

In connection with the issuance of the \$250.0 million of 9.25% Senior Notes on July 30, 2013, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 30, 2014. On March 28, 2014, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was completed on April 29, 2014.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of the Partnership's material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several and any subsidiaries of the Partnership, other than the subsidiary guarantors, are minor. There are no restrictions on the Partnership's ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants, including limitations of the Partnership's ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of the Partnership's assets. The Partnership was in compliance with these covenants as of December 31, 2014.

The aggregate amount of the Partnership's debt maturities is as follows (in thousands):

Years Ended December 31:	
2015	\$—
2016	—
2017	—
2018	696,000
2019	—
Thereafter	700,000
Total principle maturities	1,396,000
Unamortized premium	364
Unamortized discounts	(1,904)
Total debt	\$1,394,460

Total cash payments for interest by the Partnership were \$58.7 million, \$17.9 million and \$3.1 million for the years ended December 31, 2014, 2013, and 2012, respectively.

NOTE 9 – DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps, collars and options, in connection with its commodity and interest rate price risk management activities. Management enters into financial instruments to hedge forecasted commodity sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange

obligations of money as the underlying commodities are sold. Under commodity-based swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. To manage the risk of regional commodity price differences, the Partnership occasionally enters into basis swaps. Basis swaps are contractual arrangements that guarantee a price differential for a commodity from a specified delivery point price and the comparable national exchange price. For natural gas basis swaps, which have negative differentials to NYMEX, the Partnership receives or pays a payment from the counterparty if the price differential to NYMEX is greater or less than the stated terms of the contract. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right, but not the obligation, to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

Management applies the principles of hedge accounting for derivatives qualifying as hedges. Accordingly, management formally documents all relationships between the Partnership's hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching the commodity and interest rate derivative contracts to the forecasted transactions. Management assesses, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying item being hedged, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which are determined by management of the Partnership through the utilization of market data, will be recognized immediately within other, net in the Partnership's consolidated statements of operations. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value of derivative instruments as accumulated other comprehensive income (loss) and reclassifies the portion relating to commodity derivatives within gas and oil production revenues and the portion relating to interest rate derivatives to interest expense within the Partnership's consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, changes in fair value are recognized within other, net in the Partnership's consolidated statements of operations as they occur.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership's consolidated balance sheets as the initial value of the options. The Partnership reflected net derivative assets on its consolidated balance sheets of \$269.3 million and \$22.6 million at December 31, 2014 and 2013, respectively. Of the \$185.9 million of deferred gains in accumulated other comprehensive income on the Partnership's consolidated balance sheet at December 31, 2014, if the fair values of the instruments remain at current market values, the Partnership will reclassify \$97.2 million of gains to gas and oil production revenue on its consolidated statement of operations over the next twelve month period as these contracts expire. Aggregate gains of \$88.7 million of gas and oil production revenues will be reclassified to the Partnership's consolidated statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future commodity price changes. In 2014 and 2013, approximately \$8.7 million and \$3.4 million of derivative gains were reclassified from other comprehensive income (loss) related to derivative instruments entered into during the years ended December 31, 2014 and 2013, respectively.

The following table summarizes the gains or losses recognized in the Partnership's consolidated statements of operations for effective derivative instruments for the periods indicated (in thousands):

	Years Ended December 31,		
	2014	2013	2012
(Gain) loss reclassified from accumulated other comprehensive income:			
Gas and oil production revenue	\$7,084	\$(9,722)	\$(19,281)
Total	\$7,084	\$(9,722)	\$(19,281)

The following table summarizes the gross fair values of the Partnership's derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on the Partnership's consolidated balance sheets for the periods indicated (in thousands):

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Assets Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets			
As of December 31, 2014			
Current portion of derivative assets	\$ 141,464	\$ (98)	\$ 141,366
Long-term portion of derivative assets	128,303	(370)	127,933
Total derivative assets	\$ 269,767	\$ (468)	\$ 269,299
As of December 31, 2013			
Current portion of derivative assets	\$ 2,664	\$ (773)	\$ 1,891
Long-term portion of derivative assets	31,146	(4,062)	27,084
Current portion of derivative liabilities	4,341	(4,341)	—
Long-term portion of derivative liabilities	122	(122)	—
Total derivative assets	\$ 38,273	\$ (9,298)	\$ 28,975
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Balance Sheets
Offsetting Derivative Liabilities			
As of December 31, 2014			
Current portion of derivative liabilities	\$ (98)	\$ 98	\$ —
Long-term portion of derivative liabilities	(370)	370	—
Total derivative liabilities	\$ (468)	\$ 468	\$ —
As of December 31, 2013			
Current portion of derivative assets	\$ (773)	\$ 773	\$ —
Long-term portion of derivative assets	(4,062)	4,062	—
Current portion of derivative liabilities	(10,694)	4,341	(6,353)
Long-term portion of derivative liabilities	(189)	122	(67)
Total derivative liabilities	\$ (15,718)	\$ 9,298	\$ (6,420)

The Partnership enters into commodity future option and collar contracts to achieve more predictable cash flows by hedging its exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile Exchange (“NYMEX”) futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the physical delivery of the commodity. Crude oil contracts are based on a West Texas Intermediate (“WTI”) index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts have qualified and been designated as cash flow hedges and were recorded at their fair values.

During the year ended December 31, 2013, the Partnership entered into contracts which provided the option to enter into swap contracts for future production periods (“swaptions”) up through September 30, 2013 for production volumes related to assets acquired from EP Energy (see Note 4). In connection with the swaption contracts, the Partnership paid premiums of \$14.5 million, which represented their fair value on the date the transactions were initiated and were initially recorded as derivative assets on the Partnership’s consolidated balance sheet and was fully amortized as of September 30, 2013. Swaption contract premiums paid are amortized over the period from initiation of the contract through their termination date. For the year ended December 31, 2013, the Partnership recognized \$14.5 million, of amortization expense in other, net on the Partnership’s consolidated statement of operations related to the swaption contracts.

During the year ended December 31, 2012, the Partnership entered into swaptions contracts up through May 31, 2012 for production volumes related to wells acquired from Carrizo (see Note 4). In connection with the swaption contracts, the Partnership paid premiums of \$4.6 million, which represented their fair value on the date the transactions were initiated and were initially recorded as derivative assets on the Partnership's consolidated balance sheet and were fully amortized as of June 30, 2012. For the year ended December 31, 2012, the Partnership recorded approximately \$4.6 million of amortization expense in other, net on the Partnership's consolidated statement of operations related to the swaption contracts.

In June 2012, the Partnership received approximately \$3.9 million in net proceeds from the early termination of natural gas and oil derivative positions for production periods from 2015 through 2016. In conjunction with the early termination of these derivatives, the Partnership entered into new derivative positions at prevailing prices at the time of the transaction. The net proceeds from the early termination of these derivatives were used to reduce indebtedness under the Partnership's credit facility (see Note 8). The gain recognized upon the early termination of these derivative positions will continue to be reported in accumulated other comprehensive income (loss) and will be reclassified into the Partnership's consolidated statements of operations in the same periods in which the hedged production revenues would have been recognized in earnings.

The Partnership recognized losses of \$7.1 million and gains of \$9.7 million, and \$19.3 million for the years ended December 31, 2014, 2013, and 2012, respectively, on settled contracts covering commodity production. These gains and loss were included within gas and oil production revenue in the Partnership's consolidated statements of operations. As the underlying prices and terms in the Partnership's derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the years ended December 31, 2014, 2013, and 2012, respectively, for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At December 31, 2014, the Partnership had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu) ⁽¹⁾	Average Fixed Price (per MMBtu) ⁽¹⁾	Fair Value Asset (in thousands) ⁽²⁾
2015	54,834,500	\$ 4.226	\$ 65,393
2016	53,546,300		