ATLAS PIPELINE PARTNERS LP
Form 10-K
March 02, 2009
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

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: 1-14998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1550 Coraopolis Heights Road Moon Township, Pennsylvania	**15108**
(Address of principal executive office)	**(Zip code)**

Registrant s telephone number, including area code: (412) 262-2830

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

Title of each class	Name of each exchange on which registered
Common Units representing Limited Partnership Interests	**New York Stock Exchange**

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

None

(Title of class)

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

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

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

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

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

Large accelerated filer x	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 Act). Yes ¨ No x

The aggregate market value of the equity securities held by non-affiliates of the registrant, based upon the closing price of $39.06 per common limited partner unit on June 30, 2008, was approximately $1,569.3 million.

The number of common units of the registrant outstanding on February 20, 2009 was 45,960,558.

DOCUMENTS INCORPORATED BY REFERENCE: None

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO ANNUAL REPORT

ON FORM 10-K

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, may, 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 price volatility and demand for natural gas and natural gas liquids;*
- *our ability to connect new wells to our gathering systems;*
- *our ability to integrate newly acquired businesses with our operations;*
- *adverse effects of governmental and environmental regulation;*
- *limitations on our access to capital or on the market for our common units; and*
- *the strength and financial resources of our competitors.*

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

General

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL . We are a leading provider of natural gas gathering services in the Anadarko, Arkoma and Permian Basins and the Golden Trend in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing and treatment services in Oklahoma and Texas. We also provide interstate gas transmission services in southeastern Oklahoma, Arkansas, southern Kansas and southeastern Missouri. We conduct our business in the midstream segment of the natural gas industry through two reportable segments: our Mid-Continent operations and our Appalachian operations.

Through our Mid-Continent operations, we own and operate:

- a Federal Energy Regulatory Commission (FERC)-regulated, 565-mile interstate pipeline system (Ozark Gas Transmission), that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and has throughput capacity of approximately 500 million cubic feet per day (MMcfd);

- eight natural gas processing plants with aggregate capacity of approximately 810 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, located in Oklahoma and Texas; and

- 9,100 miles of active natural gas gathering systems located in Oklahoma, Arkansas, Kansas and Texas, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing and treating plants or Ozark Gas Transmission, as well as third-party pipelines.

Through our Appalachian operations, we own and operate 1,835 miles of natural gas gathering systems located in eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee. Through an omnibus agreement and other agreements between us and Atlas America, Inc. (Atlas America NASDAQ: ATLS) and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin and a publicly-traded company (NYSE: ATN), we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. Among other things, the omnibus agreement requires Atlas Energy to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America and Atlas Energy under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport.

Our general partner, Atlas Pipeline Partners GP, LLC (Atlas Pipeline GP or the General Partner), manages our operations and activities through its ownership of our 2% general partner interest. Atlas Pipeline GP is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (Atlas Pipeline Holdings or AHD), a publicly traded Delaware limited partnership (NYSE: AHD).

Since our initial public offering in January 2000, we have completed seven acquisitions at an aggregate purchase price of approximately $2.4 billion, including most recently:

- In July 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). At the date of acquisition, the Chaney Dell system included 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum system included 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which we contributed $1.9 billion and Anadarko contributed the Anadarko Assets. We funded the purchase price in part from our private placement of $1.125 billion of our common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by Atlas Pipeline Holdings, the parent of our general partner. We funded the remaining purchase price from $830.0 million of proceeds from a senior secured term loan which matures in July 2014 and a new $300.0 million senior secured revolving credit facility that matures in July 2013. Our general partner, which holds all of our incentive distribution rights, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. Our general partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the general partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter. In connection with this acquisition, we

Table of Contents

reached an agreement with Pioneer Natural Resources Company (Pioneer NYSE: PXD), which currently holds an approximate 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer has an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system which began on June 15, 2008 and ended on November 1, 2008, and up to an additional 7.4% interest beginning on June 15, 2009 and ending on November 1, 2009 (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009). If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22.0% interest if fully exercised. We will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options; and

In May 2006, we acquired the remaining 25% ownership interest in NOARK Pipeline System, Limited Partnership (NOARK) from Southwestern Energy Company (Southwestern) for a net purchase price of $65.5 million, consisting of $69.0 million in cash to the seller, (including the repayment of the $39.0 million of outstanding NOARK notes at the date of acquisition), less the seller s interest in working capital at the date of acquisition of $3.5 million. In October 2005, we acquired from Enogex, a wholly-owned subsidiary of OGE Energy Corp., all of the outstanding equity of Atlas Arkansas, which owned the initial 75% ownership interest in NOARK, for $163.0 million, plus $16.8 million for working capital adjustments and related transaction costs. NOARK s principal assets include the Ozark Gas Transmission system, a 565-mile interstate natural gas pipeline, and Ozark Gas Gathering, a 365-mile natural gas gathering system.

Both our Mid-Continent and Appalachian operations are located in areas of abundant and long-lived natural gas production and significant new drilling activity. The Ozark Gas Transmission system, which is a part of the NOARK system, and our gathering systems are connected to approximately 7,800 central delivery points or wells, giving us significant scale in our service areas. We provide gathering and processing services to the wells connected to our systems, primarily under long-term contracts. We provide fee-based, FERC-regulated transmission services through Ozark Gas Transmission under both long-term and short-term contractual arrangements. As a result of the location and capacity of the Ozark Gas Transmission system and our gathering and processing assets, we believe that we are strategically positioned to capitalize on the significant increase in drilling activity in our service areas and the positive price differential across Ozark Gas Transmission, also known as basis spread. We intend to continue to expand our business through strategic acquisitions and internal growth projects, subject to the availability of adequate capital resources and liquidity that increase distributable cash flow.

The Midstream Natural Gas Gathering, Processing and Transmission Industry

The midstream natural gas gathering and processing industry is characterized by regional competition based on the proximity of gathering systems and processing plants to producing natural gas wells.

The natural gas gathering process begins with the drilling of wells into natural gas or oil bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of small diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Gathering systems are operated at design pressures that will maximize the total throughput from all connected wells.

While natural gas produced in some areas, such as certain regions of the Appalachian Basin, does not require treatment or processing, natural gas produced in many other areas, such as our Velma service area in Oklahoma, is not suitable for long-haul pipeline transmission or commercial use and must be compressed, transported via pipeline to a central processing facility, and then processed to remove the heavier hydrocarbon components such as natural gas liquids (NGLs) and other contaminants that would interfere with pipeline transmission or the end use of the natural gas. Natural gas processing plants generally treat (remove carbon dioxide and hydrogen sulfide) and remove the NGLs, enabling the treated, dry gas (stripped of liquids) to

Table of Contents

meet pipeline specification for long-haul transport to end users. After being separated from natural gas at the processing plant, the mixed NGL stream, commonly referred to as y-grade or raw mix, is typically transported on pipelines to a centralized facility for fractionation into discrete NGL purity products: ethane, propane, normal butane, isobutane, and natural gasoline.

Natural gas transmission pipelines receive natural gas from producers, other mainline transmission pipelines, shippers and gathering systems through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial end-users, utilities and other pipelines. Generally natural gas transmission agreements generate revenue for these systems based on a fee per unit of volume transported.

Contracts and Customer Relationships

Our principal revenue is generated from the transportation and sale of natural gas and NGLs. Variables that affect our revenue are:

- the volumes of natural gas we gather, transport and process which, in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas they produce, and the demand for natural gas and NGLs; and

- the transportation and processing fees we receive which, in turn, depend upon the price of the natural gas and NGLs we transport and process, which itself is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States.

In our Appalachian region, substantially all of the natural gas we transport is for Atlas Energy under percentage-of-proceeds (POP) contracts, as described below, in which we earn a fee equal to a percentage, generally 16%, of the gross sales price for natural gas subject, in most cases, to a minimum of $0.35 or $0.40 per thousand cubic feet, or mcf, depending on the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has generally exceeded this minimum. The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our Mid-Continent segment revenue consists of the fees earned from our transmission, gathering and processing operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems, and then sell the natural gas, or produced NGLs, if any, off of delivery points on our systems. Under other agreements, we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. Our revenue is a function of the volume of natural gas that we gather and process and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value; we own a percentage of that commodity and are directly subject to its market value.

Keep-Whole Contracts. These contracts require us, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, we bear the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas. However, because the natural gas purchases contracted under keep-whole agreements are generally low in liquids content and meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with a portion of our keep-whole contracts is minimized.

Our Mid-Continent Operations

We own and operate a 565-mile interstate natural gas pipeline, approximately 9,900 miles of intrastate natural gas gathering systems, including approximately 800 miles of inactive pipeline, located in Oklahoma, Arkansas, southeastern Missouri, Kansas, northern and western Texas and the Texas panhandle, and eight processing plants and one stand-alone treating facility in Oklahoma and Texas. Ozark Gas Transmission transports natural gas from receipt points in eastern Oklahoma, including major intrastate pipelines, and western Arkansas, where the Arkoma Basin is located, to local distribution companies in Arkansas and Missouri and to interstate pipelines in northeastern and central Arkansas. Our gathering and processing assets service long-lived natural gas regions that continue to experience an increase in drilling activity, including the Anadarko Basin, the Arkoma Basin, the Permian Basin and the Golden Trend area of Oklahoma. Our systems gather natural gas from oil and natural gas wells and process the raw natural gas into merchantable, or residue, gas by extracting NGLs and removing impurities. In the aggregate, our Mid-Continent systems have approximately 7,800 receipt points, consisting primarily of individual connections and, secondarily, central delivery points which are linked to multiple wells. Our gathering systems interconnect with interstate and intrastate pipelines operated by ONEOK Gas Transportation, LLC, Southern Star Central Gas Pipeline, Inc., Panhandle Eastern Pipe Line Company, LP, Northern Natural Gas Company, CenterPoint Energy, Inc., ANR Pipeline Company, El Paso Natural Gas Company, Natural Gas Pipeline Company of America and Ozark Gas Transmission.

Mid-Continent Overview

The heart of the Mid-Continent region is generally defined as running from Kansas through Oklahoma, branching into northern and western Texas, southeastern New Mexico as well as western Arkansas. The primary producing areas in the region include the Hugoton field in southwestern Kansas, the Anadarko Basin in western Oklahoma, the Permian Basin in West Texas and the Arkoma Basin in western Arkansas and eastern Oklahoma.

FERC-Regulated Transmission System

Through NOARK, we own Ozark Gas Transmission, a 565-mile FERC-regulated natural gas interstate pipeline which transports natural gas from receipt points in eastern Oklahoma, including major intrastate pipelines, and Arkansas, where the Arkoma Basin and the Fayetteville and Woodford Shales are located, to local distribution companies and industrial markets in Arkansas and Missouri and to interstate pipelines in northeastern and central Arkansas. Ozark Gas Transmission delivers natural gas primarily via six interconnects with Mississippi River Transmission Corp., Natural Gas Pipeline Company of America and Texas Eastern Transmission Corp., and receives natural gas from interconnects with intrastate pipelines, including Enogex, BP s Vastar gathering system, Arkansas Oklahoma Gas Corporation, Arkansas Western Gas Company, ONEOK Gas Transmission, our own Ozark Gas Gathering system and other producer owned gas gathering systems.

Mid-Continent Gathering Systems

Chaney Dell. The Chaney Dell gathering system is located in north central Oklahoma and southern Kansas Anadarko Basin. Chaney Dell s natural gas gathering operations are conducted through two gathering systems, the Westana and Chaney Dell/Chester systems. As of December 31, 2008, the combined gathering systems had approximately 4,295 miles of natural gas gathering pipelines with approximately 3,520 receipt points.

Elk City/Sweetwater. The Elk City and Sweetwater gathering system, which we consider combined due to the close geographic proximity of the processing plants they are connected to, includes approximately 600 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma and the Texas panhandle, including the Atoka and Granite Wash plays. The Elk City and Sweetwater gathering system connects to approximately 600 receipt points, with a majority of the system s western end located in areas of active drilling.

Midkiff/Benedum. The Midkiff/Benedum gathering system, which we operate and have an approximate 72.8% ownership in at December 31, 2008, consists of approximately 2,650 miles of gas gathering pipeline and approximately 2,700 receipt points located across four counties within the Permian Basin in Texas. Pioneer, the largest active driller in the Spraberry Trend and a major producer in the Permian Basin, owns the remaining interest in the Midkiff/Benedum system.

When we acquired control of the Midkiff/Benedum system in July 2007, we and Pioneer agreed to extend the existing gas sales and purchase agreement to 2022 and entered into an agreement under which Pioneer has the right to increase its ownership interest in the Midkiff/Benedum system by an additional 14.6% which began June 15, 2008 and ended on November 1, 2008, and an additional 7.4% beginning June 15, 2009 and ending on November 15, 2009, for an aggregate ownership interest of 49.2% (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009). The gas sales and purchase agreement requires that all Pioneer wells in the proximity of the Midkiff/Benedum system be dedicated to that system s gathering and processing operations in return for specified natural gas processing rates. Through this agreement, we anticipate that we will continue to provide gathering and processing for the majority of Pioneer s wells in the Spraberry Trend of the Permian Basin.

Ozark Gas Gathering. Through NOARK, we own Ozark Gas Gathering, which owns 370 miles of intrastate natural gas gathering pipeline located in eastern Oklahoma and western Arkansas, providing access to both the well-established Arkoma Basin and the newly-exploited Fayetteville and Woodford Shales. This system connects to approximately 282 receipt points and compresses and transports gas to interconnections with Ozark Gas Transmission and CenterPoint.

Velma. The Velma gathering system is located in the Golden Trend area of southern Oklahoma and the Barnett Shale area of northern Texas. As of December 31, 2008, the gathering system had approximately 1,200 miles of active pipeline with approximately 650 receipt points consisting primarily of individual connections and, secondarily, central delivery points which are linked to multiple wells. The system includes approximately 800 miles of inactive pipeline, much of which can be returned to active status as local drilling activity warrants.

Processing and Treating Plants

Chaney Dell. The Chaney Dell system processes natural gas through the Waynoka, Chester and Chaney Dell plants, all of which are active cryogenic natural gas processing facilities. The Chaney Dell system s processing operations have total capacity of approximately 250 MMcfd. The Waynoka processing plant, which began operations in December 2006 and became fully operational in July 2007, contains technologically advanced controls, systems and processes and demonstrates strong NGL recovery rates. The Chaney Dell plant, which was idled in the fourth quarter of 2006 when the Waynoka plant began operations, was reactivated in January 2008 because of drilling activity in the Anadarko Basin, adding 22 MMcfd of additional processing capacity.

Midkiff/Benedum. The Midkiff/Benedum system processes natural gas through the Midkiff and Benedum processing plants. The Midkiff plant is a 110 MMcfd cryogenic facility in Reagan County, Texas. The facility includes three processing trains and thirteen compressors for inlet and residue recompression. The Benedum plant is a 43 MMcfd cryogenic facility in Upton County, Texas and includes eight compressors for inlet and residue recompression. Our Midkiff/Benedum processing operations have an aggregate processing capacity of approximately 153 MMcfd.

Velma. The Velma processing plant, located in Stephens County, Oklahoma, is a cryogenic facility with a natural gas capacity of approximately 100 MMcfd. The Velma plant is one of only two facilities in the area that is capable of treating both high-content hydrogen sulfide and carbon dioxide gases which are characteristic in this area. We sell natural gas to purchasers at the tailgate of the Velma plant and sell NGL production to ONEOK Hydrocarbon. We have made capital expenditures at the facility to improve its efficiency and competitiveness, including installing electric-powered compressors rather than higher-cost natural gas-powered compressors used by many of our competitors. This results in higher margins, greater efficiency and lower fuel costs.

Elk City/Sweetwater. The Elk City, Sweetwater and Prentiss facilities are on the same gathering system and are referred to as our Elk City/Sweetwater operations. The Elk City processing plant, located in Beckham County, Oklahoma, is a cryogenic natural gas processing plant with a total capacity of approximately 130 MMcfd. We transport to, and sell natural gas to purchasers at, the tailgate of our Elk City processing plant, as well as sell NGL production to ONEOK Hydrocarbon. The Prentiss treating facility, also located in Beckham County, is an amine treating facility with a total capacity of approximately 200 MMcfd. The Sweetwater processing plant, which began operations in September 2006, is a cryogenic natural gas processing plant located in Beckham County, near the Elk City processing plant. The Sweetwater plant has a total capacity of approximately 180 MMcfd. We built the Sweetwater plant to further access natural gas production being actively developed in western Oklahoma and the Texas panhandle. Built with state-of-the-art technology, we believe that the Sweetwater plant is capable of recovering more NGLs than a lean oil processing plant. During July 2008, we completed a 60 MMcfd expansion of the Sweetwater plant, bringing its total processing capacity to 180 MMcfd. Through this expansion, we extended the system s reach into the Granite Wash play in the Hemphill County, Texas area, which we believe will continue to increase our natural gas processing and throughput volumes.

Natural Gas Supply

In the Mid-Continent, we have natural gas purchase, gathering and processing agreements with approximately 800 producers with terms ranging from one month to 20 years. These agreements provide for the purchase or gathering of natural gas under fixed-fee, percentage-of-proceeds or keep-whole arrangements. Most of the agreements provide for compression, treating, and/or low volume fees. Producers generally provide, in-kind, their proportionate share of compressor fuel required to gather the natural gas and to operate our processing plants. In addition, the producers generally bear their proportionate share of gathering system line loss and, except for keep-whole arrangements, bear natural gas plant shrinkage, or the gas consumed in the production of NGLs.

We have enjoyed long-term relationships with the majority of our Mid-Continent producers. For instance, on the Velma system, where we have producer relationships going back over 20 years, our top four producers, which accounted for a significant portion of our Velma volumes for the year ended December 31, 2008, have contracts with primary terms running into 2009 and 2010. At the end of the primary terms, most of the contracts with producers on our gathering systems have evergreen term extensions.

Natural Gas and NGL Marketing

We typically sell natural gas to several creditworthy purchasers downstream of our processing plants priced at various first-of-month indices as published in *Inside FERC*. Additionally, swing gas, which is natural gas that is sold at non-contracted prices during a current month, is sold daily at various *Platt s Gas Daily* midpoint pricing points. The Velma plant has access to ONEOK Gas Transportation, LLC, an intrastate pipeline, and Southern Star Central Gas Pipeline, Inc., an interstate pipeline. The Elk City/Sweetwater plants have access to six major interstate and intrastate downstream pipelines: Natural Gas Pipeline Company of America, Panhandle Eastern Pipe Line Company, LP, CenterPoint Energy, Inc., Northern Natural Gas Company, ANR Pipeline Company and ONEOK Gas Transportation, LLC. The Chaney Dell and Chester plants have access to Panhandle Eastern Pipe Line Company, LP and the Waynoka plant has access to Panhandle

Table of Contents

Eastern Pipe Line Company, LP and Southern Star Central Gas Pipeline, Inc. The Midkiff/Benedum plants have access to Northern Natural Gas Company and El Paso Natural Gas Company. As negotiated in specific agreements, third party producers are allowed to deliver their gas in-kind to the above listed delivery points at all facilities.

We sell our NGL production to ONEOK Hydrocarbon under four separate agreements. The Velma agreement has an initial term expiring February 1, 2011, the Elk City/Sweetwater agreement has an initial term expiring in 2013, the Chaney Dell agreement has an initial term expiring September 1, 2009, and the Midkiff/Benedum agreement expires in 2013. All NGL agreements are priced at the average monthly Oil Price Information Service, or OPIS price for the selected market.

Condensate is collected at the Velma gas plant and around the Velma gathering system and currently sold for our account to EnerWest Trading Company, LLC. Condensate collected at the Elk City/Sweetwater plants and around the Elk City/Sweetwater gathering system is currently sold to Petro Source Partners, L.P. Condensate collected at the Chaney Dell plants and around the Chaney Dell gathering system is currently sold to Plains Marketing. Condensate collected at the Midkiff/Benedum plants and around the Midkiff/Benedum gathering system is currently sold to ConocoPhillips, Oxy USA and Oasis Transportation.

Natural Gas and NGL Hedging

Our Mid-Continent operations are exposed to certain commodity price risks. These risks result from either taking title to natural gas and NGLs, including condensate, or being obligated to purchase natural gas to satisfy contractual obligations with certain producers. We mitigate a portion of these risks through a comprehensive risk management program which employs a variety of financial tools. The resulting combination of the underlying physical business and the financial risk management program is a conversion from a physical environment that consists of floating prices to a risk-managed environment that is characterized by fixed prices.

We (a) purchase natural gas and subsequently sell processed natural gas and the resulting NGLs, or (b) purchase natural gas and subsequently sell the unprocessed natural gas, or (c) transport and/or process the natural gas for a fee without taking title to the commodities. Scenario (b) exposes us to a generally neutral price risk (long sales approximate short purchases), while scenario (c) does not expose us to any price risk; in both scenarios, risk management is not required. Scenario (a) does involve commodity risk.

We are exposed to commodity price risks when natural gas is purchased for processing. The amount and character of this price risk is a function of our contractual relationships with natural gas producers, or, alternatively, a function of cost of sales. We are therefore exposed to price risk at a gross profit level rather than at a revenue level. These cost-of-sales or contractual relationships are generally of two types:

- Percentage-of-proceeds: require us to pay a percentage of revenue to the producer. This results in our being net long physical natural gas and NGLs.

- Keep-whole: require us to deliver the same quantity of natural gas at the delivery point as we received at the receipt point; any resulting NGLs produced belong to us. This results in our being long physical NGLs and short physical natural gas.

We manage a portion of these risks by using fixed-for-floating swaps, which result in a fixed price, or by utilizing the purchase or sale of options, which result in a range of fixed prices.

We recognize gains and losses from the settlement of our derivative instruments in revenue when we sell the associated physical residue natural gas or NGLs. Any gain or loss realized as a result of the financial instrument settlement is substantially offset in the market when we sell the physical residue natural gas or NGLs. The Partnership applies the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* to its derivative instruments. We determine gains or losses on open and closed derivative transactions as the difference between the derivative contract price and the physical price. This mark-to-market methodology uses daily closing NYMEX prices when applicable and an internally-generated algorithm for commodities that are not traded on a market. To insure that these derivative instruments will be used solely for managing price risks and not for speculative purposes, we have established a committee to review our derivative instruments for compliance with our policies and procedures.

For additional information on our derivative activities and a summary of our outstanding derivative instruments as of December 31, 2008, please see Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

Our Appalachian Basin Operations

We own and operate approximately 1,835 miles of intrastate gas gathering systems located in eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee. Our Appalachian operations serve approximately 7,440 wells with an average throughput of 87.3 MMcfd of natural gas for the year ended December 31, 2008. Our gathering systems provide a means through which well owners and operators can transport the natural gas produced by their wells to interstate and public utility pipelines for delivery to customers. To a lesser extent, our gathering systems transport natural gas directly to customers. Our gathering systems connect with various public utility pipelines, including Peoples Natural Gas Company, National Fuel Gas Supply, Tennessee Gas Pipeline Company, National Fuel Gas Distribution Company, Dominion East Ohio Gas Company, Columbia Gas of Ohio, Consolidated Natural Gas Co., Texas Eastern Pipeline, Columbia Gas Transmission Corp., Equitrans Pipeline Company, Gatherco Incorporated, Piedmont Natural Gas Co., Inc., East Tennessee Natural Gas, Citizens Gas Utility District and Equitable Utilities. Our systems are strategically located in the Appalachian Basin, a region characterized by long-lived, predictable natural gas reserves that are close to major eastern U.S. markets. Substantially all of the natural gas we transport in the Appalachian Basin is derived from wells operated by Atlas Energy. We are party to an omnibus agreement with Atlas Energy which is intended to maximize the use and expansion of our gathering systems and the amount of natural gas which we transport in the region.

Appalachian Basin Overview

The Appalachian Basin includes the states of Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, West Virginia and Tennessee. The Appalachian Basin is strategically located near the energy-consuming regions of the mid-Atlantic and northeastern United States.

Natural Gas Supply

On December 18, 2006, Atlas America, which owns a 64.4% ownership interest in Atlas Pipeline Holdings, the parent of our general partner, and a direct 2.1% ownership interest in us at December 31, 2008, contributed its ownership interests in its natural gas and oil development and production subsidiaries to Atlas Energy, a then wholly-owned subsidiary of Atlas America. Concurrent with this transaction, Atlas Energy issued 7,273,750 common units, representing a then-19.4% ownership interest, in an initial public offering. Substantially all of the natural gas we transport in the Appalachian Basin is derived from wells operated by Atlas Energy.

From the inception of our operations in January 2000 through December 31, 2008, we connected 4,461 new wells to our Appalachian gathering system, 685 of which were added through acquisitions of other gathering systems. For the year ended December 31, 2008, we connected 741 wells to our gathering system. Our ability to increase the flow of natural gas through our gathering systems and to offset the natural decline of the production already connected to our gathering systems will be determined primarily by the number of wells drilled by Atlas Energy and connected to our gathering systems and by our ability to acquire additional gathering assets.

Natural Gas Revenue

Our Appalachian Basin revenue is determined primarily by the amount of natural gas flowing through our gathering systems and the price received for this natural gas. We have an agreement with Atlas Energy under which Atlas Energy pays us gathering fees generally equal to a percentage, typically 16%, of the gross weighted average sales price of the natural gas we transport subject, in most cases, to minimum prices of $0.35 or $0.40 per Mcf. For the year ended December 31, 2008, we received gathering fees averaging $1.40 per Mcf. We charge other operators fees negotiated at the time we connect their wells to our gathering systems or, in a pipeline acquisition, that were established by the entity from which we acquired the pipeline.

Because we do not buy or sell gas in connection with our Appalachian operations, we do not engage in hedging activities. Atlas Energy maintains a hedging program. Since we receive transportation fees from Atlas Energy generally based on the selling price received by Atlas Energy inclusive of the effects of financial and physical hedging, these financial and physical hedges mitigate the risk of our percentage-of-proceeds arrangements.

Our Relationship with Atlas Energy and Atlas America

We began our operations in January 2000 by acquiring the gathering systems of Atlas America. On December 18, 2006, Atlas America contributed its ownership interests in its natural gas and oil development and production subsidiaries to Atlas Energy, a then wholly-owned subsidiary of Atlas America. Atlas America owns 48.3% of Atlas Energy, 64.4% of Atlas Pipeline Holdings, the parent of our general partner, which owns a 13.9% limited partner interest and a 2% general partner interest in us. Atlas America also had a direct 2.1% ownership interest in us at December 31, 2008.

Atlas Energy and its affiliates sponsor limited and general partnerships to raise funds from investors to explore for, develop and produce natural gas and, to a lesser extent, oil from locations in eastern Ohio, western New York and western Pennsylvania. Our gathering systems are connected to approximately 6,800 wells developed and operated by Atlas Energy in the Appalachian Basin. Through agreements between us and Atlas Energy, we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. For the year ended December 31, 2008, Atlas Energy and its affiliates raised $438.4 million from investors and drilled 773 wells.

Omnibus Agreement

Under the omnibus agreement, Atlas America and its affiliates agreed to add wells to our gathering systems and provide consulting services when we construct new gathering systems or extend existing systems. In December 2006, in connection with the completion of the initial public offering of, and Atlas America s contribution and sale of its natural gas and oil development and production assets to, Atlas Energy, Atlas Energy joined the omnibus agreement as an obligor (except for the provisions of the omnibus agreement imposing conditions upon our general partner s disposition of its general partner interest in us), and Atlas America became secondarily liable as a guarantor of Atlas Energy s performance. The omnibus agreement is a continuing obligation, having no specified term or provisions regarding termination except for a provision terminating the agreement if our general partner is removed as general partner without cause. The omnibus agreement may not be amended without the approval of the conflicts committee of the managing board of our general partner if, in the reasonable discretion of our general partner, such amendment will adversely affect our common unitholders. Our common unitholders do not have explicit rights to approve any termination or material modification of the omnibus agreement. We anticipate that the conflicts committee of the managing board of our general partner would submit to our common unitholders for their approval any proposal to terminate or amend the omnibus agreement if our general partner determines, in its reasonable discretion, that the termination or amendment would materially adversely affect our common unitholders.

Table of Contents

Well Connections. Under the omnibus agreement, with respect to any well Atlas Energy drills and operates for itself or an affiliate that is within 2,500 feet of our gathering systems, Atlas Energy must, at its sole cost and expense, construct small diameter (two inches or less) sales or flow lines from the wellhead of any such well to a point of connection to the gathering system. Where an Atlas Energy well is located more than 2,500 feet from one of our gathering systems, but Atlas Energy has extended the flow line from the well to within 1,000 feet of the gathering system, Atlas Energy has the right to require us, at our cost and expense, to extend our gathering system to connect to that well. With respect to other Atlas Energy wells that are more than 2,500 feet from our gathering systems, we have the right, at our cost and expense, to extend our gathering system to within 2,500 feet of the well and to require Atlas Energy, at its cost and expense, to construct up to 2,500 feet of flow line to connect to the gathering system extension. If we elect not to exercise our right to extend our gathering systems, Atlas Energy may connect an Atlas Energy well to a natural gas gathering system owned by someone other than us or one of our subsidiaries or to any other delivery point; however, we will have the right to assume the cost of construction of the necessary flow lines, which will then become our property and part of our gathering systems.

Consulting Services. The omnibus agreement requires Atlas Energy to assist us in identifying existing gathering systems for possible acquisition and to provide consulting services to us in evaluating and making a bid for these systems. Atlas Energy must give us notice of identification by it or any of its affiliates of any gathering system as a potential acquisition candidate, and must provide us with information about the gathering system, its seller and the proposed sales price, as well as any other information or analyses compiled by Atlas Energy with respect to the gathering system. We must determine, within a time period specified by Atlas Energy s notice to us, which must be a reasonable time under the circumstances, whether we want to acquire the identified system and advise Atlas Energy of our intent. If we intend to acquire the system, we have an additional 60 days to complete the acquisition. If we advise Atlas Energy that we do not intend to make the acquisition, do not complete the acquisition within a reasonable time period, or advise Atlas Energy that we do not intend to acquire the system, then Atlas Energy may do so.

Gathering System Construction. The omnibus agreement requires Atlas Energy to provide us with construction management services if we determine we need to expand one or more of our gathering systems. We must reimburse Atlas Energy for its costs, including an allocable portion of employee salaries, in connection with its construction management services.

Disposition of Interest in Our General Partner. Before the completion of the Atlas Pipeline Holdings and Atlas Energy initial public offerings, Atlas America owned both our general partner and the entities which act as the general partners, operators or managers of the drilling investment partnerships sponsored by Atlas America. The omnibus agreement prohibited Atlas America from transferring its interest in our general partner unless it also transferred to the same person its interests in those subsidiaries. Atlas America was permitted, however, to transfer its interest in our general partner to a wholly- or majority-owned direct or indirect subsidiary as long as Atlas America continues to control the new entity. In connection with the Atlas Pipeline Holdings initial public offering, Atlas America transferred its interest in our general partner to Atlas Pipeline Holdings, then Atlas America s wholly-owned subsidiary. Atlas America currently owns a 64.4% interest in Atlas Pipeline Holdings.

Natural Gas Gathering Agreements

We entered into a master natural gas gathering agreement with Atlas America and certain of its subsidiaries in connection with the completion of our initial public offering in February 2000. In December 2006, in connection with the completion of the initial public offering of, and Atlas America s contribution and sale of its natural gas and oil development and production assets to, Atlas Energy, Atlas Energy joined the master natural gas gathering agreement as an obligor. Under the master natural gas gathering agreement, we receive a fee from Atlas Energy for gathering natural gas, determined as follows:

- for natural gas from well interests allocable to Atlas America or its affiliates (excluding general or limited partnerships sponsored by them) that were connected to our gathering systems at February 2, 2000, the greater of $0.40 per Mcf or 16% of the gross sales price of the natural gas transported;

for (i) natural gas from well interests allocable to general and limited partnerships sponsored by Atlas Energy that drill wells on or after December 1, 1999 that are connected to our gathering systems (ii) natural gas from well interests allocable to Atlas Energy or its affiliates (excluding general or limited partnerships sponsored by them) that are connected to our gathering systems after February 2, 2000, and (iii) well interests allocable to third parties in wells connected to our gathering systems at February 2, 2000, the greater of $0.35 per Mcf or 16% of the gross sales price of the natural gas transported; and

for natural gas from well interests operated by Atlas Energy and drilled after December 1, 1999 that are connected to a gathering system that is not owned by us and for which we assume the cost of constructing the connection to that gathering system, an amount equal to the greater of $0.35 per Mcf or 16% of the gross sales price of the natural gas transported, less the gathering fee charged by the other gathering system.

Atlas Energy receives gathering fees from contracts or other arrangements with third-party owners of well interests connected to our gathering systems. However, Atlas Energy must pay gathering fees owed to us from its own resources regardless of whether it receives payment under those contracts or arrangements.

The master natural gas gathering agreement is a continuing obligation and, accordingly, has no specified term or provisions regarding termination. However, if our general partner is removed as our general partner without cause, then no gathering fees will be due under the agreement with respect to new wells drilled by Atlas Energy.

The master natural gas gathering agreement may not be amended without the approval of the conflicts committee of the managing board of our general partner if, in the reasonable discretion of our general partner, such amendment will adversely affect our common unitholders. Common unitholders do not have explicit rights to approve any termination or material modification of the master natural gas gathering agreement. We anticipate that the conflicts committee of the managing board of our general partner would submit to our common unitholders for their approval any proposal to terminate or amend the master natural gas gathering agreement if our general partner determines, in its reasonable discretion, that the termination or amendment would materially adversely affect our common unitholders.

In addition to the master natural gas gathering agreement, we have three other gas gathering agreements with subsidiaries of Atlas Energy. Under two of these agreements, relating to certain wells located in southeastern Ohio and in Fayette County, Pennsylvania, we receive a fee of $0.80 per Mcf. Under the third agreement, which covers wells owned by third parties unrelated to Atlas Energy or the investment partnerships it sponsors, we receive fees that range between $0.20 to $0.29 per Mcf or between 10% to 16% of the weighted average sales price for the natural gas we transport.

Competition

Acquisitions. We have encountered competition in acquiring midstream assets owned by third parties. In several instances we submitted bids in auction situations and in direct negotiations for the acquisition of such assets and were either outbid by others or were unwilling to meet the sellers expectations. In the future, we expect to encounter equal if not greater competition for midstream assets because, as natural gas, crude oil and NGL prices increase, the economic attractiveness of owning such assets increases.

Mid-Continent. In our Mid-Continent service area, we compete for the acquisition of well connections with several other gathering/servicing operations. These operations include plants and gathering systems

Table of Contents

operated by ONEOK Field Services, Carrerra Gas Company, Copano Energy, LLC, Enogex, LLC, Eagle Rock Midstream Resources, L.P., Enbridge, Inc., Hiland Partners, MarkWest Energy Partners, L.P., Mustang Fuel Corporation, DCP Midstream, J.L. Davis and Targa Resources. We believe that the principal factors upon which competition for new well connections is based are:

- the price received by an operator or producer for its production after deduction of allocable charges, principally the use of the natural gas to operate compressors; and

- responsiveness to a well operator s needs, particularly the speed at which a new well is connected by the gatherer to its system.

We believe that our relationships with operators connected to our system are good and that we present an attractive alternative for producers. However, if we cannot compete successfully, we may be unable to obtain new well connections and, possibly, could lose wells already connected to our systems.

Being a regulated entity, Ozark Gas Transmission faces somewhat more indirect competition that is more regional or even national in character. CenterPoint Energy, Inc. s and Texas Gas Transmission s interstate systems are the nearest direct competitors.

Appalachian Basin. Our Appalachian Basin operations do not encounter direct competition in their service areas since Atlas Energy controls the majority of the drillable acreage in each area. However, because our Appalachian Basin operations principally serve wells drilled by Atlas Energy, we are affected by competitive factors affecting Atlas Energy s ability to obtain properties and drill wells, which affects our ability to expand our gathering systems and to maintain or increase the volume of natural gas we transport and, thus, our transportation revenues. Atlas Energy also may encounter competition in obtaining drilling services from third-party providers. Any competition it encounters could delay Atlas Energy in drilling wells for its sponsored partnerships, and thus delay the connection of wells to our gathering systems. These delays would reduce the volume of natural gas we otherwise would have transported, thus reducing our potential transportation revenues.

As our omnibus agreement with Atlas Energy generally requires it to connect wells it operates to our system, we do not expect any direct competition in connecting wells drilled and operated by Atlas Energy in the future. In addition, we occasionally connect wells operated by third parties. For the year ended December 31, 2008, we connected 59 third-party wells.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. FERC regulates our interstate natural gas pipeline interests. Ozark Gas Transmission transports natural gas in interstate commerce. As a result, Ozark Gas Transmission qualifies as a natural gas company under the Natural Gas Act and is subject to the regulatory jurisdiction of FERC. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce, and its authority to regulate natural gas companies includes:

- rate structures;

- rates of return on equity;

- recovery of costs;

- the services that our regulated assets are permitted to perform;

- the acquisition, construction and disposition of assets;

Table of Contents

- transactions involving the assignment of interstate pipeline capacity;
- interactions with marketing affiliates; and
- to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services, and various other matters. Natural gas companies may only charge rates that have been determined to be just and reasonable in proceedings before FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot assure you that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, transportation and storage facilities. Any successful complaint or protest against Ozark Gas Transmission s FERC-approved rates could have an adverse impact on our revenues associated with providing transmission services.

Gathering Pipeline Regulation. Section 1(b) of the Natural Gas Act exempts natural gas gathering facilities from the jurisdiction of the FERC. We own a number of intrastate natural gas pipelines in New York, Pennsylvania, Ohio, Arkansas, Kansas, Oklahoma and Texas that we believe would meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by FERC and the courts.

In Ohio, a producer or gatherer of natural gas may file an application seeking exemption from regulation as a public utility, except for the continuing jurisdiction of the Public Utilities Commission of Ohio to inspect gathering systems for public safety purposes. Our operating subsidiary has been granted an exemption by the Public Utilities Commission of Ohio for our Ohio facilities. The New York Public Service Commission imposes traditional public utility regulation on the transportation of natural gas by companies subject to its regulation. This regulation includes rates, services and siting authority for the construction of certain facilities. Our gas gathering operations currently are not subject to regulation by the New York Public Service Commission. Our operations in Pennsylvania currently are not subject to the Pennsylvania Public Utility Commission s regulatory authority since they do not provide service to the public generally and, accordingly, do not constitute the operation of a public utility. Similarly, our operations in Arkansas are not subject to rate oversight by the Arkansas Public Service Commission, but may, in certain circumstances, be subject to safety and environmental regulation by such commission or the Arkansas Oil and Gas Commission. In the event the Arkansas, Ohio, New York or Pennsylvania authorities seek to regulate our operations, we believe that our operating costs could increase and our transportation fees could be adversely affected, thereby reducing our net revenues and ability to fund our operations, pay required debt service on our credit facilities and make distributions to our general partner and common unitholders.

Nonetheless, we are currently subject to state ratable take, common purchaser and/or similar statutes in one or more jurisdictions in which we operate. Common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer, while ratable take statutes generally require gatherers to take, without discrimination, natural gas production that may be tendered to the gatherer for handling. In particular, Kansas, Oklahoma and Texas have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and discrimination with respect to rates or terms of service. Should a complaint be filed or regulation by the Kansas Corporation Commission, the Oklahoma Corporation Commission or the Texas Railroad Commission become more active, our revenues could decrease. Collectively, any of these laws may restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, the Texas Railroad Commission has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of one customer over another. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services.

Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas. A portion of our revenues is tied to the price of natural gas. The wholesale price of natural gas is not currently subject to federal regulation and, for the most part, is not subject to state regulation. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and these initiatives generally reflect more light-handed regulation. We cannot predict the ultimate impact of these regulatory changes on our operations, and we note that some of FERC s more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any such FERC action materially differently than other companies with whom we compete.

Energy Policy Act of 2005. The Energy Policy Act contains numerous provisions relevant to the natural gas industry and to interstate pipelines in particular. Overall, the legislation attempts to increase supply sources by engaging in various studies of the overall resource base and attempting to advantage deep water production on the Outer Continental Shelf in the Gulf of Mexico. However, the primary provisions of interest to our interstate pipelines focus on two areas: (1) infrastructure development; and (2) market transparency and enhanced enforcement. Regarding infrastructure development, the Energy Policy Act includes provisions to clarify that FERC has exclusive jurisdiction over the siting of liquefied natural gas (LNG) terminals; provides for market-based rates for new storage facilities placed into service after the date of enactment; shortens depreciable life for gathering facilities; statutorily designates FERC as the lead agency for federal authorizations and permits; creates a consolidated record for all federal decisions relating to necessary authorizations and permits with respect to LNG terminals and interstate natural gas pipelines; and provides for expedited judicial review of any agency action and review by only the D.C. Circuit Court of Appeals of any alleged failure of a federal agency to act by a deadline set by FERC as lead agency. Such provisions, however, do not apply to review and authorization under the Coastal Zone Management Act of 1972. Regarding market transparency and manipulation rules, the Natural Gas Act has been amended to prohibit market manipulation and add provisions for FERC to prescribe rules designed to encourage the public provision of data and reports regarding the price of

Table of Contents

natural gas in wholesale markets. The Natural Gas Act and the Natural Gas Policy Act were also amended to increase monetary criminal penalties to $1,000,000 from current law at $5,000 and to add and increase civil penalty authority to be administered by FERC to $1,000,000 per day per violation without any limitation as to total amount.

Environmental Matters

The operation of pipelines, plant and other facilities for gathering, compressing, treating, processing, or transporting natural gas, natural gas liquids and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction and operating activities in sensitive areas such as wetlands, coastal regions, tribal lands or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operators; and
- enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and 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 substances or wastes have been disposed or otherwise released. 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 substances or wastes into the environment.

We believe that our operations are in substantial compliance with applicable environmental laws and regulations and that 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 you that 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.

Hazardous Waste. Our operations generate wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

Table of Contents

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or CERCLA, also known as Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum as well as natural gas is excluded from CERCLA s definition of hazardous substance, in the course of our ordinary operations we will generate wastes that may fall within the definition of a hazardous substance. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several, strict liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for the costs of certain health studies.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. In fact, there is evidence that petroleum spills or releases have occurred at some of the properties owned or leased by us. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbons or wastes 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 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 closure operations to prevent future contamination.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain 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 strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. 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 likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, 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 to any other similarly situated companies.

Water Discharges. Our operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants is prohibited unless authorized by a permit or other agency approval. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of pollutants from our pipelines or facilities could result in administrative, civil and criminal penalties as well as significant remedial obligations.

Pipeline Safety. Our pipelines are subject to regulation by the U.S. Department of Transportation (DOT), under the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The NGPSA covers the pipeline transportation of natural gas and other gases, and the transportation and storage of liquefied natural gas and requires any entity that owns or operates pipeline facilities to comply with the regulations under the NGPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with existing NGPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA could result in increased costs.

The DOT, through the Office of Pipeline Safety, recently finalized a series of rules intended to require pipeline operators to develop integrity management programs for gas transmission pipelines that, in the event of a failure, could affect high consequence areas. High consequence areas are currently defined as areas with specified population densities, buildings containing populations of limited mobility, and areas where people gather that are located along the route of a pipeline. The Texas Railroad Commission, the Oklahoma Corporation Commission and other state agencies have adopted similar regulations applicable to intrastate gathering and transmission lines. Compliance with these rules has not had a material adverse effect on our operations but there is no assurance that this will continue in the future.

Employee Health and Safety. We are subject to the requirements of the Occupational Safety and Health Act, as amended, referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Hydrogen Sulfide. Exposure to gas containing high levels of hydrogen sulfide, referred to as sour gas, is harmful to humans, and prolonged exposure can result in death. The gas produced at our Velma gas plant contains high levels of hydrogen sulfide, and we employ numerous safety precautions at the system to ensure the safety of our employees. There are various federal and state environmental and safety requirements for handling sour gas, and we are in substantial compliance with all such requirements.

Properties

As of December 31, 2008, our principal facilities in Appalachia include approximately 1,835 miles of 2 to 12 inch diameter pipeline. Our principal facilities in the Mid-Continent area consist of eight natural gas processing plants, one treating facility, and approximately 9,900 miles of active and inactive 2 to 42 inch diameter pipeline. Substantially all of our gathering systems and our transmission pipeline are constructed within rights-of-way granted by property owners named in the appropriate land records. In a few cases, property for gathering system purposes was purchased in fee. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections. These imperfections have not interfered, and our general partner does not expect that they will materially interfere, with the conduct of our business. In many instances, lands over which rights-of-way have been obtained are subject to prior liens which have not been subordinated to the right-of-way grants. In a few instances, our rights-of-way are revocable at the election of the land owners. In some cases, not all of the owners named in the appropriate land records have joined in the right-of-way grants, but in substantially all such cases signatures of the owners of majority interests have been obtained. Substantially all permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets, and state highways, where necessary, although in some instances these permits are revocable at the election of the grantor. Substantially all permits have also been obtained from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor s election.

Certain of our rights to lay and maintain pipelines are derived from recorded gas well leases, for wells that are currently in production; however, the leases are subject to termination if the wells cease to produce. In some of these cases, the right to maintain existing pipelines continues in perpetuity, even if the well associated with the lease ceases to be productive. In addition, because many of these leases affect wells at the end of lines, these rights-of-way will not be used for any other purpose once the related wells cease to produce.

Employees

As is commonly the case with publicly-traded limited partnerships, we do not directly employ any of the persons responsible for our management or operations. In general, employees of Atlas America and its affiliates manage our gathering systems and operate our business. Atlas America employed approximately 549 people at December 31, 2008 who provided direct support to our operations.

Affiliates of our general partner will conduct business and activities of their own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition between us, our general partner and affiliates of our general partner for the time and effort of the officers and employees who provide services to our general partner. The officers of our general partner who provide services to us are not required to work full time on our affairs. These officers may devote significant time to the affairs of our general partner s affiliates and be compensated by these affiliates for the services rendered to them. There may be significant conflicts between us and affiliates of our general partner regarding the availability of these officers to manage us.

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 and our current reports on Form 8-K, available through our website at www.atlaspipelinepartners.com. 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 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108, telephone number (412) 262-2830. A complete list of our filings is available on the Securities and Exchange Commission s website at www.sec.gov. Any of our filings are also available at the Securities and Exchange Commission 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.

The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. The Chief Executive Officer of our general partner provided such certification to the NYSE in 2008 without qualification. In addition, the certifications of the Chief Executive Officer and Chief Financial Officer of our general partner required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this report.

ITEM 1A. RISK FACTORS

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. 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

The amount of cash we generate depends, in part, on factors beyond our control.

The amounts of cash that we generate may not be sufficient for us to pay distributions at our current or any other level of distribution. Our ability to make cash distributions depends primarily on our cash flow. Cash distributions do not depend directly on our profitability, which is affected by non-cash items. Therefore, cash distributions may be made during periods when we record losses and may not be made during periods when we record profits. The actual amounts of cash we generate will depend upon numerous factors relating to our business which may be beyond our control, including:

- the demand for and price of natural gas and NGLs;
- the volume of natural gas we transport;
- expiration of significant contracts;
- continued development of wells for connection to our gathering systems;
- the availability of local, intrastate and interstate transportation systems;
- the expenses we incur in providing our gathering services;
- the cost of acquisitions and capital improvements;
- our issuance of equity securities;
- required principal and interest payments on our debt;
- fluctuations in working capital;
- prevailing economic conditions;
- fuel conservation measures;
- alternate fuel requirements;
- government regulation and taxation; and
- technical advances in fuel economy and energy generation devices.

In addition, the actual amount of cash that we will have available for distribution will depend on other factors, including:

- the level of capital expenditures we make;
- the sources of cash used to fund our acquisitions;
- our debt service requirements and requirements to pay dividends on our outstanding preferred units, and restrictions on distributions contained in our current or future debt agreements; and
- the amount of cash reserves established by our general partner for the conduct of our business.

We can t borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings under our partnership agreement. Because we can t borrow money to pay distributions unless we establish a facility that meets the definition contained in our partnership agreement, our ability to pay a distribution in any quarter is solely dependent on our ability to generate sufficient operating surplus with respect to that quarter.

Table of Contents

Our financial and operating performance may fluctuate significantly from quarter to quarter. We may be unable to continue to generate sufficient cash flow to fund our operations, pay required debt service on our credit facilities and make distributions to our unitholders. If we are unable to do so, we may be required to sell assets or equity, reduce capital expenditures, refinance all or a portion of our existing indebtedness or obtain additional financing. We may be unable to do so on acceptable terms, or at all.

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

Our operations are affected by the continued financial crisis and related turmoil in the global financial system. The consequences of an economic recession and the current credit crisis include a lower level of economic activity and increased volatility in energy prices. This has resulted in a decline in energy consumption and lower market prices for oil and natural gas, and may result in a reduction in drilling activity in our service area or in wells currently connected to our pipeline system being shut in by their operators until prices improve. Any of these events may adversely affect our revenues and our ability to fund capital expenditures and in turn, may impact the cash that we have available to fund our operations, pay required debt service on our credit facilities and make distributions to our unitholders.

Recent instability in the financial markets, as a result of recession or otherwise, has increased the cost of capital while the availability of funds from those markets has diminished significantly. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our 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. Disruptions in the capital and credit markets could negatively impact our access to liquidity needed for our business and impact our flexibility to react to changing economic and business conditions. Any disruption could require us to take measures to conserve cash until the markets stabilize or until we can arrange alternative credit arrangements or other funding for our business needs. Such measures could include reducing or delaying business activities, reducing our operations to lower expenses, reducing other discretionary uses of cash, and reducing or eliminating future distributions to our unitholders. We may be unable to execute our growth strategy, take advantage of business opportunities or to respond to competitive pressures, any of which could negatively impact our business.

The current economic situation could have an adverse impact on our lenders, producers, key suppliers or other customers, causing them to fail to meet their obligations to us. 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 make required debt service payments on our credit facility and pay distributions could be impacted. The uncertainty and volatility of the global financial crisis may have further impacts on our business and financial condition that we currently cannot predict or anticipate.

Our debt levels and restrictions in our credit facility could limit our ability to fund operations, pay required debt service on our credit facility and make distributions to our unitholders.

We have a significant amount of debt. We will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms, or at all.

Table of Contents

If we do not pay distributions on our common units with respect to any fiscal quarter, our unitholders are not entitled to receive such payments 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 receive such payments in the future.

We are affected by the volatility of prices for natural gas and NGL products.

We derive a majority of our gross margin from POP and keep-whole contracts. As a result, our income depends to a significant extent upon the prices at which we buy and sell natural gas and at which we sell NGLs and condensate. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based upon estimated unhedged market prices of $0.76 per gallon, $6.50 per mmbtu and $55.00 per barrel for NGLs, natural gas and condensate, respectively, would change our gross margin for the twelve-month period ended December 31, 2009 by approximately $25.3 million. Additionally, changes in natural gas prices may indirectly impact our profitability since prices can influence drilling activity and well operations, and could cause operators of wells currently connected to our pipeline system or that we expect will be connected to our system to shut us in until prices improve, thereby affecting the volume of gas we gather and process. Historically, the price of both natural gas and NGLs has been subject to significant volatility in response to relatively minor changes in the supply and demand for natural gas and NGL products, market uncertainty and a variety of additional factors beyond our control, including those we describe in The amount of cash we generate depends in part on factors beyond our control, above. Oil and natural gas prices have been extremely volatile recently and have declined substantially. On December 19, 2008, the price of oil on the New York Mercantile Exchange fell to $33.87 per barrel for January 2009 delivery, declining to an approximate five-year low from a high of $147.27 per barrel in July 2008. We expect this volatility to continue. This volatility may cause our gross margin and cash flows to vary widely from period to period. Our risk management strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the throughput volumes. Moreover, derivative instruments are subject to inherent risks, which we describe in Our price risk management strategies may fail to protect us and could reduce our gross margin and cash flow.

The amount of natural gas we transport will decline over time unless we are able to attract new wells to connect to our gathering systems.

Production of natural gas from a well generally declines over time until the well can no longer economically produce natural gas and is plugged and abandoned. Failure to connect new wells to our gathering systems could, therefore, result in the amount of natural gas we transport declining substantially over time and could, upon exhaustion of the current wells, cause us to abandon one or more of our gathering systems and, possibly, cease operations. The primary factors affecting our ability to connect new supplies of natural gas to our gathering systems include our success in contracting for existing wells that are not committed to other systems, the level of drilling activity near our gathering systems and, in the Mid-Continent region, our ability to attract natural gas producers away from our competitors gathering systems.

Over time, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. A decrease in exploration and development activities in the fields served by our gathering and processing facilities and pipeline transportation systems could result if there is a sustained decline in natural gas prices which, in turn, would lead to a reduced utilization of these assets. The decline in the credit markets, the lack of availability of credit, debt or equity financing and the decline in natural gas prices may result in a reduction of producers exploratory drilling. We have no control over the level of drilling activity in our service areas, the amount of reserves underlying wells that connect to our systems and the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, drilling costs, geological considerations, governmental regulation and the availability and cost of capital. In a low price environment, such as currently exists, producers may determine to shut in wells already connected to our systems until prices improve. Because our operating costs are fixed to a significant degree, a reduction in the natural gas volumes we transport or process would result in a reduction in our gross margin and cash flows.

Table of Contents

The amount of natural gas we transport, treat or process may be reduced if the natural gas liquids pipelines to which we deliver NGLs cannot or will not accept the NGLs.

If one or more of the pipelines to which we deliver NGLs has service interruptions, capacity limitations or otherwise does not accept the NGLs we sell to or transport on, and we cannot arrange for delivery to other pipelines, the amount of NGLs we sell or transport may be reduced. Since our revenues depend upon the volumes of NGLs we sell or transport, this could result in a material reduction in our gross margin and cash flows.

The success of our Appalachian operations depends upon Atlas Energy s ability to drill and complete commercial producing wells.

Substantially all of the wells we connect to our gathering systems in our Appalachian service area are drilled and operated by Atlas Energy for drilling investment partnerships sponsored by it. As a result, our Appalachian operations depend principally upon the success of Atlas Energy in sponsoring drilling investment partnerships and completing wells for these partnerships. Atlas Energy operates in a highly competitive environment for acquiring undeveloped leasehold acreage and attracting capital. Atlas Energy may not be able to compete successfully in the future in acquiring undeveloped leasehold acreage or in raising additional capital through its drilling investment partnerships. Furthermore, Atlas Energy is not required to connect wells for which it is not the operator to our gathering systems. If Atlas Energy cannot or does not continue to sponsor drilling investment partnerships, if the amount of money raised by those partnerships decreases, or if the number of wells actually drilled and completed as commercially producing wells decreases, the amount of natural gas transported by our Appalachian gathering systems would substantially decrease and could, upon exhaustion of the wells currently connected to our gathering systems, cause us to abandon one or more of our Appalachian gathering systems, thereby materially reducing our gross margin and cash flows.

The failure of Atlas Energy to perform its obligations under our natural gas gathering agreements with it may adversely affect our business.

Substantially all of our Appalachian operating system revenues currently consist of the fees we receive under the master natural gas gathering agreement and other transportation agreements we have with Atlas Energy and its affiliates. We expect to derive a material portion of our gross margin from the services we provide under our contracts with Atlas Energy for the foreseeable future. Any factor or event adversely affecting Atlas Energy s business or its ability to perform under its contracts with us or any default or nonperformance by Atlas Energy of its contractual obligations to us, could reduce our gross margin and cash flows.

The success of our Mid-Continent operations depends upon our ability to continually find and contract for new sources of natural gas supply from unrelated third parties.

Unlike our Appalachian operations, none of the drillers or operators in our Mid-Continent service area is an affiliate of ours. Moreover, our agreements with most of the producers with which our Mid-Continent operations do business generally do not require them to dedicate significant amounts of undeveloped acreage to our systems. While we do have some undeveloped acreage dedicated on our systems, most notably with our partner Pioneer on our Midkiff/Benedum system, we do not have assured sources to provide us with new wells to connect to our Mid-Continent gathering systems. Failure to connect new wells to our Mid-Continent operations will, as described in The amount of natural gas we transport will decline over time unless we are able to attract new wells to connect to our gathering systems, above, will reduce our gross margin and cash flows.

Table of Contents

Our Mid-Continent operations currently depend on certain key producers for their supply of natural gas; the loss of any of these key producers could reduce our revenues.

During 2008, Chesapeake Energy Corporation, Pioneer, Sandridge Energy, Inc., Conoco Phillips, XTO Energy Inc., Henry Petroleum, L.P., Linn Energy, LLC and Apache Corporation supplied our Mid-Continent systems with a majority of their natural gas supply. If these producers reduce the volumes of natural gas that they supply to us, our gross margin and cash flows would be reduced unless we obtain comparable supplies of natural gas from other producers.

The curtailment of operations at, or closure of, any of our processing plants could harm our business.

If operations at any of our processing plants were to be curtailed, or closed, whether due to accident, natural catastrophe, environmental regulation or for any other reason, our ability to process natural gas from the relevant gathering system and, as a result, our ability to extract and sell NGLs, would be harmed. If this curtailment or stoppage were to extend for more than a short period, our gross margin and cash flows would be materially reduced.

We may face increased competition in the future in our Mid-Continent service areas.

Our Mid-Continent operations may face competition for well connections. DCP Midstream, LLC, ONEOK, Inc., Carrera Gas Company, Copano Energy, LLC and Enogex, LLC operate competing gathering systems and processing plants in our Velma service area. In our Elk City and Sweetwater service area, ONEOK Field Services, Eagle Rock Midstream Resources, L.P., Enbridge Energy Partners, L.P., CenterPoint Energy, Inc., MarkWest Energy Partners, L.P. and Enogex LLC operate competing gathering systems and processing plants. CenterPoint Energy, Inc. s and Texas Gas Transmission s interstate system is the nearest direct competitor to our Ozark Gas Transmission system. CenterPoint and Hiland Partners operate competing gathering systems in Ozark Gas Gathering s service area. Hiland Partners, DCP Midstream, Mustang Fuel Corporation and ONEOK Partners operate competing gathering systems and processing plants in our Chaney Dell service area. DCP Midstream, J.L. Davis, and Targa Resources operate competing gathering systems and processing plants in our Midkiff/Benedum service area. Some of our competitors have greater financial and other resources than we do. If these companies become more active in our Mid-Continent service areas, we may not be able to compete successfully with them in securing new well connections or retaining current well connections. If we do not compete successfully, the amount of natural gas we transport, process and treat will decrease, reducing our gross margin and cash flows.

The amount of natural gas we transport, treat or process may be reduced if the public utility and interstate pipelines to which we deliver gas cannot or will not accept the gas.

Our gathering systems principally serve as intermediate transportation facilities between sales lines from wells connected to our systems and the public utility or interstate pipelines to which we deliver natural gas. If one or more of these pipelines has service interruptions, capacity limitations or otherwise does not accept the natural gas we transport, and we cannot arrange for delivery to other pipelines, local distribution companies or end users, the amount of natural gas we transport may be reduced. Since our revenues depend upon the volumes of natural gas we transport, this could result in a material reduction in our gross margin and cash flows.

The scope and costs of the risks involved in making acquisitions may prove greater than estimated at the time of the acquisition.

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

- the risk that reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- mistaken assumptions about revenues and costs, including synergies;

Table of Contents

- significant increases in our indebtedness and working capital requirements;
- delays in obtaining any required regulatory approvals of third party consents;
- the imposition of conditions on any acquisition by a regulatory authority;
- an inability to integrate successfully or timely the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns;
- increased demands on existing personnel;
- customer or key employee losses at the acquired businesses; and
- the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately 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 impact our future growth and our ability to make or increase distributions.

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

We have an active, on-going program to identify potential acquisitions. Our integration of previously independent operations with our own can be a complex, costly and time-consuming process. The difficulties of combining these systems with its existing systems 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 pipeline safety-related records and procedures;
- 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.

Our investment in the interconnection of our Elk City/Sweetwater and Chaney Dell systems and the additional overhead costs we incur to grow our NGL business may not deliver the expected incremental volume or cash flow. Costs incurred and liabilities assumed in connection with the 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.

Table of Contents

The acquisitions of the Chaney Dell and the Midkiff/Benedum systems have substantially changed our business, making it difficult to evaluate our business based upon our historical financial information.

The acquisitions of the Chaney Dell and the Midkiff/Benedum systems have significantly increased our size and substantially redefined our business plan, expanded our geographic market and resulted in large changes to our revenues and expenses. As a result of these acquisitions, and our continued plan to acquire and integrate additional companies that we believe present attractive opportunities, our financial results for any period or changes in our results across periods may continue to dramatically change. Our historical financial results, therefore, should not be relied upon to accurately predict our future operating results, thereby making the evaluation of our business more difficult.

Due to our lack of asset diversification, negative developments in our operations would reduce our ability to fund our operations, pay required debt service on our credit facilities and make distributions to our unitholders.

We rely exclusively on the revenues generated from our transportation, gathering and processing operations, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to our lack of asset-type diversification, a negative development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

Our construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could impair our results of operations and financial condition.

One of the ways we may grow our business is through the construction of new assets, such as our recent expansion of our Sweetwater plant. The construction of additions or modifications to our existing systems and facilities, and the construction of new assets, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and require the expenditure of significant amounts of capital. Any projects we undertake may not be completed on schedule at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a gathering system, the construction may occur over an extended period of time, and we will not receive any material increase in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which growth does not materialize. Since we are not engaged in the exploration for and development of natural gas reserves, we often do not have access to estimates of potential reserves in an area before constructing facilities in the area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, the estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could impair our results of operations and financial condition. In addition, our actual revenues from a project could materially differ from expectations as a result of the price of natural gas, the NGL content of the natural gas processed and other economic factors described in this section.

We recently completed construction of an expansion to our Sweetwater natural gas processing plant, from which we expect to generate additional incremental cash flow. We also continue to expand the natural gas gathering system surrounding Sweetwater in order to maximize its plant throughput. In addition to the risks discussed above, expected incremental revenue from the Sweetwater natural gas processing plant could be reduced or delayed due to the following reasons:

- difficulties in obtaining equity or debt financing for additional construction and operating costs;
- difficulties in obtaining permits or other regulatory or third-party consents;
- additional construction and operating costs exceeding budget estimates;
- revenue being less than expected due to lower commodity prices or lower demand;

Table of Contents

difficulties in obtaining consistent supplies of natural gas; and

terms in operating agreements that are not favorable to us.

If we are unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then our cash flows could be reduced.

The construction of additions to our existing gathering assets may require us to obtain new rights-of-way before constructing new pipelines. We may be unable to obtain rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then our cash flows could be reduced.

Regulation of our gathering operations could increase our operating costs, decrease our revenues, or both.

Currently our gathering and processing of natural gas is exempt from regulation under the Natural Gas Act of 1938. However, the implementation of new laws or policies, or changed interpretations of existing laws, could subject our gathering and processing operations to regulation by FERC under the Natural Gas Act, the Natural Gas Policy Act, or other laws enacted after the date of this Form 10-K. Any such regulation would increase our costs, decrease our gross margin and cash flows, or both.

Even if our gathering and processing operations are not generally subject to regulation under the Natural Gas Act, FERC regulation will still affect our business and the market for our products. FERC s policies and practices affect a range of our natural gas pipeline activities, including, for example, its policies on interstate natural gas pipeline open access transportation, ratemaking, capacity release, environmental protection and market center promotion, which indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

Since federal law generally leaves any economic regulation of natural gas gathering to the states, state and local regulations may also affect our business. Matters subject to such regulation include access, rates, terms of service and safety. For example, our gathering lines are subject to ratable take, common purchaser, and similar statutes in one or more jurisdictions in which we operate. Common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer, while ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Texas and Oklahoma have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and discrimination with respect to rates or terms of service. Should a complaint be filed or regulation by the Texas Railroad Commission or Oklahoma Corporation Commission become more active, our revenues could decrease. Collectively, all of these statutes may restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Increased regulatory requirements relating to the integrity of the Ozark Gas Transmission pipeline and our other assets could require us to spend additional money to comply with these requirements. In particular, Ozark Gas Transmission is subject to extensive laws and regulations related to pipeline integrity. Federal legislation signed into law in December 2002 includes guidelines for the U.S. Department of Transportation and pipeline companies in the areas of testing, education, training and communication. Compliance with existing and recently enacted regulations requires significant expenditures. Additional laws and regulations that may be enacted in the future, such as U.S. Department of Transportation implementation of additional hydrostatic testing requirements, could significantly increase the amount of these expenditures.

Table of Contents

Ozark Gas Transmission is subject to FERC rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating the pipeline.

FERC s rate-making policies could affect Ozark Gas Transmission s ability to establish rates, or to charge rates that would cover future increases in its costs, or even to continue to collect rates that cover current costs. Natural gas companies may only charge rates that have been determined to be just and reasonable by FERC. The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot assure you that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas capacity and transportation facilities. Any successful complaint or protest against Ozark Gas Transmission s rates could reduce our revenues associated with providing transmission services. We cannot assure you that we will be able to recover all of Ozark Gas Transmission s costs through existing or future rates.

Ozark Gas Transmission is subject to regulation by FERC in addition to FERC rules and regulations related to the rates it can charge for its services.

FERC s regulatory authority also extends to:

- operating terms and conditions of service;
- the types of services Ozark Gas Transmission s may offer to its customers;
- transactions involving the assignment of interstate pipeline capacity;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- accounts and records, as well as periodic reporting requirements; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

FERC action in any of these areas or modifications of its current regulations could impair Ozark Gas Transmission s ability to compete for business, increase the costs it incurs in its operations, limit the construction of new facilities or its ability to recover the full cost of operating its pipeline. For example, revisions to interstate gas quality standards by FERC could create two distinct markets for natural gas an interstate market subject to minimum quality standards and an intrastate market with different minimum quality standards. Such a bifurcation of markets could make it difficult for our pipelines to compete in both markets or to attract certain gas supplies away from the intrastate market. The time FERC takes to approve the construction of new facilities could raise the costs of our projects to the point where they are no longer economic.

FERC has authority over the terms and conditions of interstate pipeline services. Under FERC s open access requirements, service generally must be undertaken pursuant to the terms and conditions of the pipeline s open access tariff. Contracts for such services that deviate in a material manner from a pipeline s tariff must be filed for approval by FERC or, alternatively, the pipeline must amend its generally available tariff to include the deviating terms, thereby offering it to all shippers. If FERC audits a pipeline s contracts and finds deviations that appear to be unduly discriminatory, FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Table of Contents

Should Ozark Gas Transmission fail to comply with all applicable FERC administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1,000,000 per day for each violation.

Finally, we cannot give any assurance regarding the likely future regulations under which we will operate Ozark Gas Transmission or the effect such regulation could have on our business, financial condition, and results of operations.

Compliance with pipeline integrity regulations issued by the DOT and state agencies could result in substantial expenditures for testing, repairs and replacement.

DOT and state agency regulations require pipeline operators to develop integrity management programs for transportation pipelines located in high consequence areas. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

We do not believe that the cost of implementing integrity management program testing along certain segments of our pipeline will have a material effect on our results of operations. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial.

Our midstream natural gas operations may incur significant costs and liabilities resulting from a failure to comply with new or existing environmental regulations or a release of hazardous substances into the environment.

The operations of our gathering systems, plant and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. These laws and regulations can restrict or impact our business activities in many ways, including restricting the manner in which we dispose of substances, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. 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. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. 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 substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations including releases of substances into the environment, and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, 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 could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance.

We may not be able to execute our growth strategy successfully.

Our strategy contemplates substantial growth through both the acquisition of other gathering systems and processing assets and the expansion of our existing gathering systems and processing assets. Our growth strategy involves numerous risks, including:

- we may not be able to identify suitable acquisition candidates;
- we may not be able to make acquisitions on economically acceptable terms for various reasons, including limitations on access to capital and increased competition for a limited pool of suitable assets;
- our costs in seeking to make acquisitions may be material, even if we cannot complete any acquisition we have pursued;
- irrespective of estimates at the time we make an acquisition, the acquisition may prove to be dilutive to earnings and operating surplus;
- we may encounter delays in receiving regulatory approvals or may receive approvals that are subject to material conditions;
- we may encounter difficulties in integrating operations and systems; and
- any additional debt we incur to finance an acquisition may impair our ability to service our existing debt.

Limitations on our access to capital or the market for our common units will impair our ability to execute our growth strategy.

Our ability to raise capital for acquisitions and other capital expenditures depends upon ready access to the capital markets. Historically, we have financed our acquisitions, and to a much lesser extent, expansions of our gathering systems by bank credit facilities and the proceeds of public and private debt and equity offerings of our common units and preferred units of our operating partnership. If we are unable to access the capital markets, we may be unable to execute our strategy of growth through acquisitions.

We may issue additional units, which may increase the risk of not having sufficient available cash to maintain or increase our per unit distribution level.

We have wide discretion to issue additional units, including units that rank senior to our common units as to quarterly cash distributions, on the terms and conditions established by our general partner. The payment of distributions on these additional units may increase the risk that we will not be able to maintain or increase our per unit distribution level. To the extent new units are senior to our common units, their issuance will increase the uncertainty of the payment of distributions on the common units.

Table of Contents

Our price risk management strategies may fail to protect us and could reduce our gross margin and cash flow.

We pursue various hedging strategies to seek to reduce our exposure to losses from adverse changes in the prices for natural gas, condensate and NGLs. Our price risk management activities will vary in scope based upon the level and volatility of natural gas, condensate and NGL prices and other changing market conditions. Our price risk management activity may fail to protect or could harm us because, among other things:

- entering into derivative instruments can be expensive, particularly during periods of volatile prices;
- available derivative instruments may not correspond directly with the risks against which we seek protection;
- the duration of the derivative instrument may not match the duration of the risk against which we seek protection; and
- the party owing money in the derivative transaction may default on its obligation to pay.

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

With the objective of enhancing the predictability of future revenues, from time to time we enter into natural gas, natural gas liquids and crude oil derivative contracts. We account for these derivative contracts by applying the provisions of SFAS No. 133. Due to 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 our recognizing a non-cash loss in our consolidated statements of operations or through accumulated other comprehensive income (loss) and a consequent non-cash decrease in our partners capital between reporting periods. Any such decrease could be substantial. In addition, we may be required to make a cash payment upon the termination of any of these derivative contracts.

Our risk management activities do not eliminate our exposure to fluctuations in commodity prices and interest rates and may reduce our cash flow and subject our earnings to increased volatility.

Our operations expose us to fluctuations in commodity prices. We utilize derivative contracts related to the future price of crude oil, natural gas and NGLs with the intent of reducing the volatility of our cash flows due to fluctuations in commodity prices. We also have exposure to interest rate fluctuations as a result of variable rate debt under our term loan and revolving credit facility. We have entered into interest rate swap agreements to convert a portion of this variable rate debt to a fixed rate obligation, thereby reducing our exposure to market rate fluctuations.

We have entered into derivative transactions related to only a portion of our crude oil, natural gas and NGL volume and our variable rate debt. As a result, we will continue to have direct commodity price risk and interest rate risk with respect to the unhedged portion of these items. To the extent we protect our commodity price and interest rate risk using certain derivative contracts, we will forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

Even though our price risk management activities are monitored by management, these activities could reduce our cash flow in some circumstances, including if the counterparty to the derivative instrument defaults on its contract obligations, if there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received or, with regard to commodity derivatives, if production is less than expected. With respect to commodity derivative contracts, if the actual amount of production is lower than the amount that is subject to our derivative instruments, we might be forced to satisfy all or a portion of derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our cash flow. In addition, we have entered into proxy hedges with respect to our

Table of Contents

NGLs, typically using crude oil derivative contracts, based upon the historical price correlation between crude oil and NGLs. Certain of these proxy hedges could become less effective as a result of significant increases in the price of crude oil and less significant increases in the price of ethane and propane. If these proxy hedges remain less effective, our settlement of the contracts could result in significant costs to us.

The accounting standards regarding hedge accounting are complex, and even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our financial statements may reflect volatility due to these derivatives, even when there is no underlying economic impact at that point. 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.

Litigation or governmental regulation relating to environmental protection and operational safety may result in substantial costs and liabilities.

Our operations are subject to federal and state environmental laws under which owners of natural gas pipelines can be liable for clean-up costs and fines in connection with any pollution caused by their pipelines. We may also be held liable for clean-up costs resulting from pollution which occurred before our acquisition of the gathering systems. In addition, we are subject to federal and state safety laws that dictate the type of pipeline, quality of pipe protection, depth, methods of welding and other construction-related standards. Any violation of environmental, construction or safety laws could impose substantial liabilities and costs on us.

We are also subject to the requirements of OSHA, and comparable state statutes. Any violation of OSHA could impose substantial costs on us.

We cannot predict whether or in what form any new legislation or regulatory requirements might be enacted or adopted, nor can we predict our costs of compliance. In general, we expect that new regulations would increase our operating costs and, possibly, require us to obtain additional capital to pay for improvements or other compliance action necessitated by those regulations.

We are subject to operating and litigation risks that may not be covered by insurance.

Our operations are subject to all operating hazards and risks incidental to transporting and processing natural gas and NGLs. These hazards include:

- damage to pipelines, plants, related equipment and surrounding properties caused by floods and other natural disasters;
- inadvertent damage from construction and farm equipment;
- leakage of natural gas, NGLs and other hydrocarbons;
- fires and explosions;
- other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations; and
- acts of terrorism directed at our pipeline infrastructure, production facilities, transmission and distribution facilities and surrounding properties.

As a result, we may be a defendant in various legal proceedings and litigation arising from our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable

rates. As a result of market conditions, premiums and deductibles for some of our insurance policies have increased substantially, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, our gross margin and cash flows would be materially reduced.

The IRS could treat us as a corporation for tax purposes, which could substantially reduce our cash flow.

If we were treated as a corporation for U.S. federal income tax purposes for any taxable year for which the statute of limitations remains open or any future year, we would pay federal income tax on our taxable income for such year at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Because a tax would be imposed on us as a corporation, our cash flow would be substantially reduced.

Risks Related to Our Ownership Structure

Atlas America and its affiliates, including Atlas Energy, have conflicts of interest and limited fiduciary responsibilities, which may permit them to favor their own interests to the detriment of our unitholders.

Atlas America and its affiliates own and control our general partner, which also owns a 13.9% limited partner interest in us. We do not have any employees and rely solely on employees of Atlas America and its affiliates who serve as our agents, including all of the senior managers who operate our business. A number of officers and employees of Atlas America also own interests in us. Conflicts of interest may arise between Atlas America, our general partner and their affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over our interests and the interests of our unitholders. These conflicts include, among others, the following situations:

- Employees of Atlas America who provide services to us also devote significant time to the businesses of Atlas America in which we have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the employees who provide services to our general partner, which could result in insufficient attention to the management and operation of our business.

- Neither our partnership agreement nor any other agreement requires Atlas America to pursue a future business strategy that favors us or, apart from our agreements with Atlas America relating to our Appalachian region operations, use our assets for transportation or processing services we provide. Atlas America s directors and officers have a fiduciary duty to make these decisions in the best interests of the stockholders of Atlas America.

- Our general partner is allowed to take into account the interests of parties other than us, such as Atlas America, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to us.

- Our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates, including our agreements with Atlas Energy.

Conflicts of interest with Atlas America and its affiliates, including the foregoing factors, could exacerbate periods of lower or declining performance, or otherwise reduce our gross margin and cash flows.

Cost reimbursements due our general partner may be substantial and will reduce the cash available for distributions to our unitholders.

We reimburse Atlas America, our general partner and their affiliates, including officers and directors of Atlas America, for all expenses they incur on our behalf. Our general partner has sole discretion to determine the amount of these expenses. In addition, Atlas America and its affiliates provide us with services for which we are charged reasonable fees as determined by Atlas America in its sole discretion. The reimbursement of expenses or payment of fees could adversely affect our ability to fund our operations, pay required debt service on our credit facilities and make distributions to our unitholders.

Our control of the Chaney Dell and Midkiff/Benedum systems is limited by provisions of the limited liability company operating agreements with Anadarko and, with respect to the Midkiff/Benedum system, the operation and expansion agreement with Pioneer.

The managing member of each of the limited liability companies which owns the interests in the Chaney Dell and Midkiff/Benedum systems is our subsidiary. However, the consent of Anadarko is required for specified extraordinary transactions, such as admission of new members, engaging in transactions with our affiliates not approved by the company conflicts committee, incurring debt outside the ordinary course of business and disposing of company assets above specified thresholds. The Midkiff/Benedum system is also governed by an operation and expansion agreement with Pioneer which gives system owners having at least a 60% interest in the system the right to approve the annual operating budget and capital investment budget and to impose other limitations on the operation of the system. Thus, a holder of a greater than 40% interest in the system would effectively have a veto right over the operation of the system. Pioneer currently owns an approximate 27% interest in the system but, pursuant to the purchase option agreement, has the right to acquire up to an additional 22% interest.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is contained within Item 1, Business .

ITEM 3. LEGAL PROCEEDINGS

We are not subject to any pending material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of the common unitholders during the year ended December 31, 2008.

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 under the symbol APL . At the close of business on February 24, 2009, the closing price for the common units was $5.50 and there were 132 record holders, one of which is the holder for all beneficial owners who hold in street name.

Table of Contents

The following table sets forth the range of high and low sales prices of our common units and distributions declared by quarter per unit on our common limited partner units for the years ended December 31, 2008 and 2007:

	High	Low	Distributions Declared
2008			
Fourth Quarter	$ 26.00	$ 4.68	$ 0.38
Third Quarter	$ 40.03	$ 22.77	$ 0.96
Second Quarter	$ 44.00	$ 37.50	$ 0.96
First Quarter	$ 45.99	$ 38.75	$ 0.94
2007			
Fourth Quarter	$ 49.58	$ 41.92	$ 0.93
Third Quarter	$ 55.50	$ 42.62	$ 0.91
Second Quarter	$ 56.88	$ 47.81	$ 0.87
First Quarter	$ 51.70	$ 46.64	$ 0.86

For a description of our recent sale of unregistered securities, see our current report on Form 8-K filed January 6, 2009.

Our partnership agreement requires that we distribute 100% of available cash to our general partner and common limited partners 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 by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds 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. When our general partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners 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 to common unitholders exceed specified targets, as follows:

Minimum Distributions Per Unit Per Quarter	Percent of Available Cash in Excess of Minimum Allocated to the General Partner
$0.42	15%
$0.52	25%
$0.60	50%

We make distributions of available cash to common unitholders regardless of whether the amount distributed is less than the minimum quarterly distribution. 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. During July 2007, our general partner, the holder of all of our incentive distribution rights, had agreed to allocate up to $5.0 million of incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter, in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems. AHD also agreed that the resulting allocation of incentive distribution rights back to us would be after AHD receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007 and $7.0 million per quarter thereafter. The general partner s incentive distributions declared for the year ended December 31, 2008, after the allocation of $13.8 million of its incentive distribution rights back to us, were $23.5 million.

Table of Contents

For information concerning 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 .

ITEM 6. SELECTED FINANCIAL DATA

The following table should be read together with our consolidated financial statements and notes thereto included within Item 8, Financial Statements and Supplementary Data and Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations of this report. We have derived the selected financial data set forth in the table for each of the years ended December 31, 2008, 2007 and 2006 and at December 31, 2008 and 2007 from our consolidated financial statements appearing elsewhere in this report, which have been audited by Grant Thornton LLP, independent registered public accounting firm. We derived the financial data as of December 31, 2006, 2005 and 2004 and for the years ended December 31, 2005 and 2004 from our consolidated financial statements, which were audited by Grant Thornton LLP and are not included within this report.

	Years Ended December 31,				
	2008	2007[(1)]	2006[(2)]	2005[(3)]	2004[(4)]
	(in thousands, except per unit and operating data)				
Statement of operations data:					
Revenue:					
Natural gas and liquids	$ 1,370,000	$ 761,118	$ 391,356	$ 338,672	$ 72,364
Transportation, compression and other fees	99,709	81,785	60,924	30,309	18,800
Other income (loss), net	(55,519)	(174,103)	12,412	2,519	127
Total revenue and other income (loss), net	1,414,190	668,800	464,692	371,500	91,291
Costs and expenses:					
Natural gas and liquids	1,086,142	587,524	334,299	288,180	58,707
Plant operating	60,835	34,667	15,722	10,557	2,032
Transportation and compression	17,886	13,484	10,753	4,053	2,260
General and administrative[(5)]	417	60,986	22,569	13,608	4,643
Depreciation and amortization	90,124	50,982	22,994	13,954	4,471
Goodwill and other asset impairment loss	698,508				
Gain on early extinguishment of debt	(19,867)				
Loss (gain) on arbitration settlement, net				138	(1,457)
Interest	84,843	61,526	24,572	14,175	2,301
Minority interests[(6)]	(22,781)	3,940	118	1,083	
Total costs and expenses	1,996,107	813,109	431,027	345,748	72,957
Net income (loss)	(581,917)	(144,309)	33,665	25,752	18,334
Preferred unit imputed dividend cost	(505)	(2,494)	(1,898)		
Preferred unit dividends	(1,769)				
Preferred unit dividend effect		(3,756)			
Premium on preferred unit redemption					(400)
Net income (loss) attributable to common limited partners and the general partner	$ (584,191)	$ (150,559)	$ 31,767	$ 25,752	$ 17,934
Net income (loss) attributable to common limited partners per unit:					
Basic	$ (15.62)	$ (6.75)	$ 1.29	$ 1.86	$ 2.53
Diluted[(7)]	$ (15.62)	$ (6.75)	$ 1.27	$ 1.84	$ 2.53
Balance sheet data (at period end):					
Property, plant and equipment, net	$ 2,022,937	$ 1,748,661	$ 607,097	$ 445,066	$ 175,259

Total assets	2,445,533	2,877,614	786,884	742,726	216,785
Total debt, including current portion	1,493,427	1,229,426	324,083	298,625	54,452
Total partners capital	683,179	1,273,960	379,134	329,510	136,704

Table of Contents

Cash flow data:					
Net cash provided by (used in) operating activities	$ (58,758)	$ 99,769	$ 45,029	$ 49,520	$ 24,301
Net cash used in investing activities	(292,944)	(2,024,643)	(104,499)	(409,607)	(150,905)
Net cash provided by financing activities	341,242	1,935,059	27,028	376,110	129,740
Other financial data (unaudited):					
Gross margin [8]	$ 411,231	$ 263,532	$ 119,891	$ 79,711	$ 32,457
EBITDA [9]	260,887	(21,378)	82,321	52,791	25,106
Adjusted EBITDA [9]	316,548	183,510	87,140	56,509	25,596
Maintenance capital expenditures	$ 6,674	$ 9,115	$ 4,649	$ 1,922	$ 1,516
Expansion capital expenditures	319,260	130,532	79,067	49,179	7,635
Total capital expenditures	$ 325,934	$ 139,647	$ 83,716	$ 51,101	$ 9,151
Operating data (unaudited)[10]:					
Appalachia:					
Average throughput volumes (mcfd)	87,299	68,715	61,892	55,204	53,343
Mid-Continent:					
Velma system:					
Gathered gas volume (mcfd)	63,196	62,497	60,682	67,075	56,441
Processed gas volume (mcfd)	60,147	60,549	58,132	62,538	55,202
Residue gas volume (mcfd)	47,497	47,234	45,466	50,880	42,659
NGL volume (bpd)	6,689	6,451	6,423	6,643	5,799
Condensate volume (bpd)	280	225	193	256	185
Elk City/Sweetwater system:					
Gathered gas volume (mcfd)	280,860	298,200	277,063	250,717	
Processed gas volume (mcfd)	232,664	225,783	154,047	119,324	
Residue gas volume (mcfd)	210,399	206,721	140,969	109,553	
NGL volume (bpd)	10,487	9,409	6,400	5,303	
Condensate volume (bpd)	332	212	140	127	
Chaney Dell system[11]:					
Gathered gas volume (mcfd)	276,715	259,270			
Processed gas volume (mcfd)	245,592	253,523			
Residue gas volume (mcfd)	239,498	221,066			
NGL volume (bpd)	13,263	12,900			
Condensate volume (bpd)	791	572			
Midkiff/Benedum system[11]:					
Gathered gas volume (mcfd)	144,081	147,240			
Processed gas volume (mcfd)	135,496	141,568			
Residue gas volume (mcfd)	92,019	94,281			
NGL volume (bpd)	19,538	20,618			
Condensate volume (bpd)	1,142	1,346			
NOARK system:					
Average Ozark Gas Transmission throughput volume (mcfd)	442,464	326,651	249,581	255,777	

(1) Includes our acquisition of control of a 100% interest in the Chaney Dell natural gas gathering system and processing plants and a 72.8% undivided joint interest in the Midkiff/Benedum natural gas gathering system and processing plants on July 27, 2007, representing approximately five months operations for the year ended December 31, 2007. Operating data for the Chaney Dell and Midkiff/Benedum systems represent 100% of its operating activity.

(2) Includes our acquisition of the remaining 25% ownership interest in NOARK on May 2, 2006, representing approximately eight months of an additional 25% ownership interest in NOARK s operations for the year ended December 31, 2006. Operating data for the NOARK system represents 100% of its operating activity.

(3) Includes our acquisition of Elk City on April 14, 2005, representing approximately eight and one-half months operations, and a 75% ownership interest in NOARK on October 31, 2005, representing approximately two months operations, for the year ended December 31, 2005. Operating data for the NOARK system represents 100% of its operating activity.

(4) Includes our acquisition of the Velma system on July 16, 2004, representing approximately five and one-half months operations for the year ended December 31, 2004.

(5) Includes non-cash compensation (income) expense of ($34.0) million, $36.3 million, $6.3 million, $4.7 million and $0.7 million for the years ended December 31, 2008, 2007, 2006, 2005 and 2004, respectively.

(6) For the years ended December 31, 2006 and 2005, this represents Southwestern s 25% minority interest in the net income of NOARK. We acquired Southwestern s 25% ownership interest on May 2, 2006. For the years ended December 31, 2008 and 2007, this represents Anadarko s 5% minority interest in the operating results of the Chaney Dell and Midkiff Benedum systems, which we acquired on July 27, 2007.

(7) For the years ended December 31, 2008 and 2007, approximately 901,000 and 524,000 phantom units, respectively, were excluded from the computation of diluted net income (loss) attributable to common limited partner units because the inclusion of such units would have been anti-dilutive. For the years ended December 31, 2008, 2007 and 2006, potential common limited partner units issuable upon conversion of our $1,000 par value Class A and Class B cumulative convertible preferred limited partner units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

(8) We define gross margin as revenue less purchased product costs. Purchased product costs include the cost of natural gas and NGLs that we purchase from third parties. Gross margin, as we define it, does not include plant operating and transportation and compression expenses as movements in gross margin generally do not result in directly correlated movements in these cost categories. Plant operating and transportation and compression expenses generally include the costs required to operate and maintain our pipelines and processing facilities, including salaries and wages, repair and maintenance expense, real estate taxes and other overhead costs. Our management views gross margin as an important performance measure of core profitability for our operations and as a key component of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses. The following table reconciles our net income (loss) to gross margin (in thousands):

	Years Ended December 31,				
	2008	**2007(1)**	**2006(2)**	**2005(3)**	**2004(4)**
Net income (loss)	$ (581,917)	$ (144,309)	$ 33,665	$ 25,752	$ 18,334
Adjustments:					
Effect of prior period items(12)			1,090	(1,090)	
Other (income) loss, net	55,519	174,103	(12,412)	(2,519)	(127)
Plant operating	60,835	34,667	15,722	10,557	2,032
Transportation and compression	17,886	13,484	10,753	4,053	2,260
General and administrative(5)	417	60,986	22,569	13,608	4,643
Depreciation and amortization	90,124	50,982	22,994	13,954	4,471
Goodwill and other asset impairment loss	698,508				
Loss (gain) on arbitration settlement, net				138	(1,457)
Interest	84,843	61,526	24,572	14,175	2,301
Minority interests(6)	(22,781)	3,940	118	1,083	
Non-cash linefill loss (gain)(13)	7,797	(2,270)	820		
Unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition(14)		10,423			
Gross margin	$ 411,231	$ 263,532	$ 119,891	$ 79,711	$ 32,457

(9) EBITDA represents net income (loss) before net interest expense, income taxes, and depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances, principally to directors and employees, and other cash items such as the non-recurring cash derivative early termination expense (see Note 15). EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing EBITDA and Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies. The Adjusted EBITDA calculation below is similar to the EBITDA calculation under our credit facility.

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity s financial performance, such as their cost of capital and its tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA and Adjusted EBITDA because they provide investors and management with additional information to better understand our operating performance and are presented solely as a supplemental financial measure. EBITDA and Adjusted EBITDA should not be considered as alternatives to, or more meaningful than, net income or cash flow as determined in accordance with generally accepted accounting principles or as indicators of our operating performance or liquidity. The following table reconciles net income (loss) to EBITDA and EBITDA to Adjusted EBITDA (in thousands):

Table of Contents

	Years Ended December 31, 2008	2007[1]	2006[2]	2005[3]	2004[4]
Net income (loss)	$ (581,917)	$ (144,309)	$ 33,665	$ 25,752	$ 18,334
Adjustments:					
Effect of prior period items[12]			1,090	(1,090)	
Interest expense	84,843	61,526	24,572	14,175	2,301
Depreciation and amortization	90,124	50,982	22,994	13,954	4,471
Goodwill and other asset impairment loss, net of associated minority interest	667,837				
Unrecognized economic impact of Chaney Dell and Midkiff/Benedum acquisition[14]		10,423			
EBITDA	$ 260,887	$ (21,378)	$ 82,321	$ 52,791	$ 25,106
Adjustments:					
Non-cash (gain) loss on derivative movements	(115,767)	169,424	(2,316)	(954)	(210)
Non-recurring cash derivative early termination expense[15]	197,641				
Non-cash compensation (income) expense	(34,010)	36,306	6,315	4,672	700
Non-cash line fill loss (gain) [13]	7,797	(2,270)	820		
Other non-cash items[16]		1,414			
Adjusted EBITDA	$ 316,548	$ 183,496	$ 87,140	$ 56,509	$ 25,596

(10) Mcf represents thousand cubic feet; mcfd represents thousand cubic feet per day; bpd represents barrels per day.

(11) Volumetric data for the Chaney Dell and Midkiff/Benedum systems for the year ended December 31, 2007 represents volumes recorded for the 158-day period from July 27, 2007, the date of our acquisition, through December 31, 2007.

(12) During June 2006, we identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and first quarter of 2006, we recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively.

(13) Includes the non-cash impact of commodity price movements on pipeline linefill inventory.

(14) The acquisition of the Chaney Dell and Midkiff/Benedum systems was consummated on July 27, 2007, although the acquisition s effective date was July 1, 2007. As such, we receive the economic benefits of ownership of the assets as of July 1, 2007. However, in accordance with generally accepted accounting principles, we have only recorded the results of the acquired assets commencing on the closing date of the acquisition. The economic benefits of ownership we received from the acquired assets from July 1 to July 27, 2007 were recorded as a reduction of the consideration paid for the assets.

(15) During the year ended December 31, 2008, we made net payments of $274.0 million, which resulted in a net cash expense recognized of $197.6 million, related to the early termination of derivative contracts that were principally entered into as proxy hedges for the prices received on the ethane and propane portion of our NGL equity volume. These derivative contracts were put into place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. These settlements were funded through our June 2008 issuance of 5.75 million common limited partner units in a public offering and issuance of 1.39 million common limited partner units to Atlas Pipeline Holdings, L.P. (NYSE: AHD), the owner of our general partner, and Atlas America, Inc. (NASDAQ: ATLS), the parent of Atlas Pipeline Holdings, L.P. s general partner, in a private placement. In connection with this transaction, we also entered into an amendment to our credit facility to revise the definition of Consolidated EBITDA to allow for the add-back of charges relating to the early termination of certain derivative contracts for debt covenant calculation purposes when the early termination of derivative contracts is funded through the issuance of common equity.

(16) Includes the cash proceeds received from the sale of our Enville plant and the non-cash loss recognized within our statements of operations.

Table of Contents

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

The following discussion provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with our consolidated financial statements and related notes thereto appearing elsewhere in this report.

General

We are a publicly-traded Delaware limited partnership whose common units are listed on the New York Stock Exchange under the symbol APL . Our principal business objective is to generate cash for distribution to our unitholders. We are a leading provider of natural gas gathering services in the Anadarko, Arkoma, and Permian Basins and the Golden Trend in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing and treatment services in Oklahoma and Texas. We also provide interstate gas transmission services in southeastern Oklahoma, Arkansas, southern Kansas and southeastern Missouri. Our business is conducted in the midstream segment of the natural gas industry through two reportable segments: our Mid-Continent operations and our Appalachian operations.

Through our Mid-Continent operations, we own and operate:

- a FERC-regulated, 565-mile interstate pipeline system (Ozark Gas Transmission) that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and which has throughput capacity of approximately 500 MMcfd;

- eight active natural gas processing plants with aggregate capacity of approximately 810 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, located in Oklahoma and Texas; and

- 9,100 miles of active natural gas gathering systems located in Oklahoma, Arkansas, Kansas and Texas, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing and treating plants or Ozark Gas Transmission, as well as third party pipelines.

Through our Appalachian operations, we own and operate 1,835 miles of natural gas gathering systems located in eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee. Through an omnibus agreement and other agreements between us and Atlas America, Inc., (Atlas America NASDAQ: ATLS) and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin and a publicly-traded company (NYSE: ATN), we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. Among other things, the omnibus agreement requires Atlas Energy to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America and Atlas Energy under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport.

Recent Events

In December 2008, we sold 10,000 newly-created 12% cumulative convertible Class B preferred units of limited partner interest (the Class B Preferred Units) to AHD for cash consideration of $1,000 per Class B Preferred Unit pursuant to a purchase agreement. AHD has the right, before March 30, 2009, to purchase an additional 10,000 Class B Preferred Units on the same terms. We used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units will receive distributions of 12% per annum, paid quarterly on the same date as the distribution payment date for our common units. See Convertible Preferred Units Class B Preferred Units).

In December 2008, we repurchased approximately $60.0 million in face amount of our senior unsecured notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million in face amount of our 8.125% senior unsecured notes and approximately $27.0 million in face amount of our 8.75% senior unsecured notes. All of the senior unsecured notes repurchased have been retired and are not available for re-issue.

In June 2008, we sold 5,750,000 common units in a public offering at a price to the public of $37.52, resulting in approximately $206.6 million of net proceeds. Also in June 2008, we sold 278,000 common units to AHD and 1,112,000 common units to Atlas America, Inc. (NASDAQ: ATLS ATLS), the parent of AHD s general partner, in a private placement at a net price of $36.02, resulting in approximately $50.1 million of net proceeds. In addition, we received approximately $5.4 million from our general partner to maintain its aggregate 2% general partner interest in us.

The net proceeds from the public and private placement offerings of our common units were utilized to fund the early termination of a majority of derivative contracts that we entered into as proxy hedges for the prices we receive for the ethane and propane portion of our NGL equity volume. These derivative contracts, which related to production periods ranging from the end of second quarter of 2008 through the fourth quarter of 2009, were put in place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 (see Significant Acquisitions). We estimate that we incurred a charge during the second quarter 2008 of approximately $10.6 million due to the decline in the price correlation of crude oil and ethane and propane. Our net income for the year ended December 31, 2008 includes a net $197.6 million cash derivative expense resulting from the aggregate net payments of $274.0 million to unwind a portion of these derivative contracts.

In June 2008, we issued $250.0 million of 10-year, 8.75% senior unsecured notes (the 8.75% Senior Notes) in a private placement transaction. The sale of the 8.75% Senior Notes generated net proceeds of approximately $244.9 million, which was utilized to repay indebtedness under our senior secured term loan and revolving credit facility.

In June 2008, we obtained $80.0 million of increased commitments to our senior secured revolving credit facility, increasing our aggregate lender commitments to $380.0 million. In connection with this and the previously mentioned transactions, we also amended our senior secured credit facility to, among other things, exclude from the calculation of Consolidated EBITDA the costs associated with the termination of derivative instruments to the extent such costs are financed with or paid out of the net proceeds of an equity offering. In addition, consistent with several other recent energy master limited partnership agreements, our general partner s managing board and conflicts committee approved an amendment to our limited partnership agreement which will allow the cash expenditure to terminate derivative contracts to not reduce distributable cash flow.

Subsequent Event

On January 27, 2009, we and Sunlight Capital, the holder of outstanding Class A Preferred Units, agreed to amend certain terms of our existing preferred unit agreement. The amendment (a) increased the dividend yield from 6.5% to 12% per annum, effective January 1, 2009, (b) changed the conversion commencement date from May 8, 2008 to April 1, 2009, (c) changed the conversion price adjustment from $43.00 to $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of our common units, and (d) changed the call redemption price from $53.22 to $27.25. Simultaneously with the execution of the amendment, we issued Sunlight Capital $15.0 million of our 8.125% senior unsecured notes due 2015 to redeem 10,000 Class A Preferred Units. We also agreed that we will redeem an additional 10,000 Class A Preferred Units for cash at the liquidation value on April 1, 2009. If Sunlight does not exercise its conversion right on or before June 2, 2009, we will redeem the then-remaining 10,000 Class A Preferred Units for cash or one-half for cash and one-half for our common limited partner units on July 1, 2009.

Table of Contents

Significant Acquisitions

From the date of our initial public offering in January 2000 through December 2008, we have completed seven acquisitions at an aggregate cost of approximately $2.4 billion, including, most recently:

In July 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). At the date of acquisition, the Chaney Dell system included 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum system included 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which we contributed $1.9 billion and Anadarko contributed the Anadarko Assets. We funded the purchase price, in part, from our private placement of $1.125 billion of our common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by Atlas Pipeline Holdings, the parent of our general partner. Our general partner, which holds all of our incentive distribution rights, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter (see Partnership Distributions). We funded the remaining purchase price from $830.0 million of proceeds from a senior secured term loan which matures in July 2014 and borrowings under our senior secured revolving credit facility that matures in July 2013 (see Term Loan and Credit Facility). Our general partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the general partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter (see Partnership Distributions).

In connection with this acquisition, we reached an agreement with Pioneer Natural Resources Company, which currently holds an approximate 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer has an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system, which began on June 15, 2008 and ended on November 1, 2008, and up to an additional 7.4% interest beginning on June 15, 2009 and ending November 1, 2009 (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009). If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22.0% interest if fully exercised. We will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options.

In May 2006, we acquired the remaining 25% ownership interest in NOARK from Southwestern Energy Company (Southwestern) for a net purchase price of $65.5 million, consisting of $69.0 million in cash to the seller, (including the repayment of the $39.0 million of outstanding NOARK notes at the date of acquisition), less the seller s interest in working capital at the date of acquisition of $3.5 million. In October 2005, we acquired from Enogex, a wholly-owned subsidiary of OGE Energy Corp., all of the outstanding equity of Atlas Arkansas, which owned the initial 75% ownership interest in NOARK, for $163.0 million, plus $16.8 million for working capital adjustments and related transaction costs. NOARK s principal assets include the Ozark Gas Transmission system, a 565-mile interstate natural gas pipeline, and Ozark Gas Gathering, a 365-mile natural gas gathering system.

Contractual Revenue Arrangements

Our principal revenue is generated from the transportation and sale of natural gas and NGLs. Variables that affect our revenue are:

- the volumes of natural gas we gather, transport and process which, in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas they produce, and the demand for natural gas and NGLs; and

- the transportation and processing fees we receive which, in turn, depend upon the price of the natural gas and NGLs we transport and process, which itself is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States.

In our Appalachian region, substantially all of the natural gas we transport is for Atlas Energy under percentage-of-proceeds (POP) contracts, as described below, in which we earn a fee equal to a percentage, generally 16%, of the gross sales price for natural gas subject, in most cases, to a minimum of $0.35 to $0.40 per thousand cubic feet, or mcf, depending on the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has exceeded this minimum generally. The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our Mid-Continent segment revenue consists of the fees earned from our transmission, gathering and processing operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems, and then sell the natural gas, or produced NGLs, if any, off of delivery points on our systems. Under other agreements, we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. Our revenue is a function of the volume of natural gas that we gather and process and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value; we own a percentage of that commodity and are directly subject to its market value.

Keep-Whole Contracts. These contracts require us, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, we bear the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas. However, because the natural gas purchases contracted under keep-whole agreements are generally low in liquids content and meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with a portion of our keep-whole contracts is minimized.

Recent Trends and Uncertainties

The midstream natural gas industry links the exploration and production of natural gas and the delivery of its components to end-use markets and provides natural gas gathering, compression, dehydration, treating, conditioning, processing, fractionation and transportation services. This industry group is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

Table of Contents

We face competition for natural gas transportation and in obtaining natural gas supplies for our processing and related services operations. Competition for natural gas supplies is based primarily on the location of gas-gathering facilities and gas-processing plants, operating efficiency and reliability, and the ability to obtain a satisfactory price for products recovered. Competition for customers is based primarily on price, delivery capabilities, flexibility, and maintenance of high-quality customer relationships. Many of our competitors operate as master limited partnerships and enjoy a cost of capital comparable to and, in some cases lower than, ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas. We believe the primary difference between us and some of our competitors is that we provide an integrated and responsive package of midstream services, while some of our competitors provide only certain services. We believe that offering an integrated package of services, while remaining flexible in the types of contractual arrangements that we offer producers, allows us to compete more effectively for new natural gas supplies in our regions of operations.

As a result of our POP and keep-whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas and NGLs. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. The number of active oil and gas rigs has increased in recent years, mainly due to recent significant increases in natural gas prices, which could result in sustained increases in drilling activity during the current and future periods. However, energy market uncertainty could negatively impact North American drilling activity in the short term. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based on estimated unhedged market prices of $0.76 per gallon, $6.50 per mmbtu and $55.00 per barrel for NGLs, natural gas and condensate, respectively, would change our gross margin for the twelve-month period ending December 31, 2009 by approximately $25.3 million.

Currently, there is an unprecedented level of uncertainty in the financial markets. This uncertainty presents additional potential risks to us. These risks include the availability and costs associated with our borrowing capabilities and raising additional capital, and an increase in the volatility of the price of our common units. While we have no definitive plans to access the capital markets, should we decide to do so in the near future, the terms, size, and cost of new debt or equity could be less favorable than in previous transactions.

Results of Operations

The following table illustrates selected volumetric information related to our reportable segments for the periods indicated:

	Years Ended December 31,		
	2008	2007	2006
Operating data(1):			
Appalachia:			
Average throughput volumes (mcfd)	87,299	68,715	61,892
Mid-Continent:			
Velma system:			
Gathered gas volume (mcfd)	63,196	62,497	60,682
Processed gas volume (mcfd)	60,147	60,549	58,132
Residue gas volume (mcfd)	47,497	47,234	45,466
NGL volume (bpd)	6,689	6,451	6,423
Condensate volume (bpd)	280	225	193
Elk City/Sweetwater system:			
Gathered gas volume (mcfd)	280,860	298,200	277,063
Processed gas volume (mcfd)	232,664	225,783	154,047
Residue gas volume (mcfd)	210,399	206,721	140,969
NGL volume (bpd)	10,487	9,409	6,400
Condensate volume (bpd)	332	212	140
Chaney Dell system(2):			
Gathered gas volume (mcfd)	276,715	259,270	
Processed gas volume (mcfd)	245,592	253,523	
Residue gas volume (mcfd)	239,498	221,066	
NGL volume (bpd)	13,263	12,900	
Condensate volume (bpd)	791	572	
Midkiff/Benedum system(2):			
Gathered gas volume (mcfd)	144,081	147,240	
Processed gas volume (mcfd)	135,496	141,568	
Residue gas volume (mcfd)	92,019	94,281	
NGL volume (bpd)	19,538	20,618	
Condensate volume (bpd)	1,142	1,346	
NOARK system:			
Average Ozark Gas Transmission throughput volume (mcfd)	442,464	326,651	249,581

(1) Mcf represents thousand cubic feet; Mcfd represents thousand cubic feet per day; Bpd represents barrels per day.
(2) Volumetric data for the Chaney Dell and Midkiff/Benedum systems for the year ended December 31, 2007 represents volumes recorded for the 158-day period from July 27, 2007, the date of acquisition, through December 31, 2007.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenue. Natural gas and liquids revenue was $1,370.0 million for the year ended December 31, 2008, an increase of $608.9 million from $761.1 million for the prior year. The increase was primarily attributable to an increase in revenue contribution from the Chaney Dell and Midkiff/Benedum systems, which we acquired in July 2007, of $512.8 million, and an increase from the Velma and Elk City/Sweetwater systems of $26.6 million and $61.8 million, respectively, due primarily to higher average commodity prices over the full year and an increase in volumes. Processed natural gas volume on the Chaney Dell system was 245.6 MMcfd for the year ended December 31, 2008, a decrease of 3.1% compared to 253.5 MMcfd for the period from its July 2007 acquisition to December 31, 2007. The Midkiff/Benedum system had processed natural gas volume of 135.5 MMcfd for the year ended December 31, 2008, a decrease of 4.3% compared to 141.6 MMcfd for the period from its July 2007 acquisition to December 31, 2007 due to the adverse effects of a hurricane which struck the surrounding area in September 2008. Processed natural gas volume averaged 60.1 MMcfd on the Velma system for the year ended December 31, 2008, a decrease of 0.7% from the comparable prior year. However, the Velma system increased its NGL production volume by 3.7% when compared to the prior year to 6,689 bpd for the year ended December 31, 2008, representing an increase in production efficiency. Processed natural gas volume on the Elk City/Sweetwater system averaged 232.7 MMcfd for the year ended December 31, 2008, an

increase of 3.0% from the prior year. NGL production volume for the Elk City/Sweetwater system was 10,487 bpd, an increase of 11.5% from the prior year, as production efficiency of the processing plants has increased. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Note 9 under Item 8, Financial Statements and Supplementary Data .

Transportation, compression and other fee revenue increased to $99.7 million for the year ended December 31, 2008 compared with $81.8 million for the prior year. This $17.9 million increase was primarily due to an $11.0 million increase from the Appalachia system due to higher throughput volume and a higher average transportation rate, $5.4 million of a full year s contributions from the Chaney Dell and Midkiff/Benedum systems, and an increase of $1.7 million associated with the Elk City/Sweetwater system. The Appalachia system s average throughput volume was 87.3 MMcfd for the year ended December 31, 2008 as compared with 68.7 MMcfd for the prior year, an increase of 18.6 MMcfd or 27.0%. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system, the acquisition of the McKean processing plant and gathering system in central Pennsylvania for $6.1 million in August 2007, and the acquisition of the Vinland processing plant and gathering system in northeastern Tennessee for $9.1 million in February 2008. For the NOARK system, average Ozark Gas Transmission volume was 442.5 MMcfd for the year ended December 31, 2008, an increase of 35.5% from the prior year due to an increase in throughput capacity to 400.0 MMcfd during the third quarter 2007 and an increase to 500.0 MMcfd during the fourth quarter 2008 and higher customer demand.

Other income (loss) net, including the impact of certain gains and losses recognized on derivatives, was a loss of $55.5 million for the year ended December 31, 2008, which represents a favorable movement of $118.6 million from the prior year loss of $174.1 million. This favorable movement was due primarily to a $356.8 million favorable movement in non-cash mark-to-market adjustments on derivatives, partially offset by a net cash loss of $200.0 million and a non-cash derivative loss of $39.2 million related to the early termination of a portion of our derivative contracts (see Recent Events), and an unfavorable movement of $1.5 million related to cash settlements on derivatives that were not designated as hedges. The $356.8 million favorable movement in non-cash mark-to-market adjustments on derivatives was due principally to a decrease in forward crude oil market prices from December 31, 2007 to December 31, 2008 and their favorable mark-to-market impact on certain non-hedge derivative contracts we have for production volumes in future periods. For example, average forward crude oil prices, which are the basis for adjusting the fair value of our crude oil derivative contracts, at December 31, 2008 were $56.94 per barrel, a decrease of $32.95 per barrel from average forward crude oil market prices at December 31, 2007 of $89.89 per barrel. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under 7A Quantitative and Qualitative Discussion About Market Risk .

Costs and Expenses. Natural gas and liquids cost of goods sold of $1,086.1 million and plant operating expenses of $60.8 million for the year ended December 31, 2008 represented increases of $498.6 million and $26.1 million, respectively, from the prior year amounts due primarily to an increase of $453.2 million in natural gas and liquids cost of goods sold and a $23.0 million increase in plant operating expenses from a full year s contribution from the Chaney Dell and Midkiff/Benedum systems, and higher average commodity prices for the full year and an increase in production volume on the Velma and Elk City/Sweetwater systems. Transportation and compression expenses increased $4.4 million to $17.9 million for the year ended December 31, 2008 due to an increase in Appalachia system operating and maintenance costs as a result of increased capacity, additional well connections and operating costs of the McKean and Vinland processing plants and gathering systems.

General and administrative expense, including amounts reimbursed to affiliates, decreased $60.6 million to $0.4 million for the year ended December 31, 2008 compared with $61.0 million for the prior year. The decrease was primarily related to a $70.3 million decrease in non-cash compensation expense, partially offset by higher costs of managing our operations, including the Chaney Dell and Midkiff/Benedum systems acquired in July 2007 and capital-raising and strategic activities. The decrease in non-cash compensation expense was principally attributable to a $36.3 million gain recognized during the year ended December 31, 2008 in comparison to an expense of $33.4 million for the prior year for certain common unit awards for which the ultimate amount to be issued was determined after the completion of our 2008 fiscal year and was based upon the financial performance of certain acquired assets (see Note 14 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data). The gain was the result of a significant change in our common unit market price at December 31, 2008 when compared with the December 31, 2007 price, which was utilized in the estimate of the non-cash compensation expense for these awards, and lower financial performance of the certain assets acquired in comparison to estimated performance.

Depreciation and amortization increased to $90.1 million for the year ended December 31, 2008 compared with $51.0 million for the year ended December 31, 2007 due primarily to the depreciation associated with our Chaney Dell and Midkiff/Benedum acquired assets and our expansion capital expenditures incurred subsequent to December 31, 2007.

Interest expense increased to $84.8 million for the year ended December 31, 2008 as compared with $61.5 million for the prior year. This $23.3 million increase was primarily due to a $14.7 million increase in interest expense associated with the term loan issued in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems (see Term Loan and Credit Facility) and $11.1 million of interest expense related to our additional senior notes issued during June 2008 (see Recent Events).

Goodwill and other asset impairment loss of $698.5 million for the year ended December 31, 2008 consisted of a $676.9 million impairment charge to our goodwill as a result of our annual goodwill impairment test and a $21.6 million write-off of costs related to a pipeline expansion project. The goodwill impairment resulted from the reduction of our estimate of the fair value of goodwill in comparison to its carrying amount at December 31, 2008. The estimate of fair value of goodwill was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. Our estimates were subjective and based upon numerous assumptions about future operations and market conditions, which are subject to change. The write-off of costs incurred consisted of preliminary construction and engineering costs as well as a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement. Management is pursuing other strategic alternatives for this project.

Gain on early extinguishment of debt of $19.9 million for the year ended December 31, 2008 resulted from our repurchase of approximately $60.0 million in face amount of our Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million in face amount of our 8.125% Senior Notes and approximately $27.0 million in face amount of our 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue (see Recent Events).

Minority interest expense decreased $26.7 million to income of $22.8 million for the year ended December 31, 2008 from $3.9 million of expense for the prior year. This decrease was primarily due to lower net income for the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to effect our acquisition of control of the respective systems. The decrease in net income of the Chaney Dell and Midkiff/Benedum joint ventures was principally due to the goodwill impairment charge of $613.4 million for the goodwill originally recognized upon acquisition of these systems. The minority interest expense represents Anadarko s 5% interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenue. Natural gas and liquids revenue was $761.1 million for the year ended December 31, 2007, an increase of $369.7 million from $391.4 million for the prior year. The increase was primarily attributable to revenue contribution from the Chaney Dell and Midkiff/Benedum systems, which we acquired in July 2007, of $344.2 million, an increase of $26.5 million from the Elk City/Sweetwater system due primarily to an increase in volumes, which includes processing volumes from the newly constructed Sweetwater gas plant, and an increase of $18.5 million from the Velma system due primarily to an increase in volumes. These increases were partially offset by a decrease of $21.0 million from the NOARK system due primarily to lower natural gas sales volumes on its gathering systems. Processed natural gas volume on the Chaney Dell system was 253.5 MMcfd for the period from July 27, 2007, the date of acquisition, to December 31, 2007, while the Midkiff/Benedum system had processed natural gas volume of 103.6 MMcfd for the same period. Processed natural gas volume on the Elk City/Sweetwater system averaged 225.8 MMcfd for the year ended December 31, 2007, an increase of 46.6% from the prior year. Processed natural gas volume averaged 60.5 MMcfd on the Velma system for the year ended December 31, 2007, an increase of 4.2% from the prior year. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices.

Transportation, compression and other fee revenue increased to $81.8 million for the year ended December 31, 2007 compared with $60.9 million for the prior year. This $20.9 million increase was primarily due to an increase of $10.4 million from the transportation revenues associated with the NOARK system, $4.0 million of contributions from the Chaney Dell and Midkiff/Benedum systems, a $3.5 million increase from the Appalachia system, and an increase of $2.9 million associated with the Elk City/Sweetwater system. For the NOARK system, average Ozark Gas Transmission volume was 326.7 MMcfd for the year ended December 31, 2007, an increase of 30.9% from the prior year. The Appalachia system s average throughput volume was 68.7 MMcfd for the year ended December 31, 2007 as compared with 61.9 MMcfd for the prior year, an increase of 6.8 MMcfd or 11.0%. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system and throughput associated with the acquisition of a processing plant and gathering system in August 2007.

Other income (loss), net, including the impact of non-cash gains and losses recognized on derivatives, was a loss of $174.1 million for the year ended December 31, 2007, a decrease of $186.5 million from the prior year. This decrease was due primarily to a $169.4 million non-cash derivative loss for the year ended December 31, 2007 compared with a $5.7 million non-cash derivative gain for the year ended December 31, 2006, an unfavorable movement of $175.2 million. This change in the non-cash impact of derivatives was the result of commodity price movements and their unfavorable impact on derivative contracts we have for production volumes in future periods. We recorded $130.2 million of non-cash derivative losses during the fourth quarter 2007, when forward crude oil prices for the duration of our derivative contracts, which are the basis for adjusting the fair value of our derivative contracts, increased from an average price of $74.78 per barrel at September 30, 2007 to $89.89 per barrel at December 31, 2007, an increase of $15.11. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices.

Costs and Expenses. Natural gas and liquids cost of goods sold of $587.5 million and plant operating expenses of $34.7 million for the year ended December 31, 2007 represented increases of $253.2 million and $18.9 million, respectively, from the prior year amounts due primarily to contribution from the Chaney Dell and Midkiff/Benedum acquisition and an increase in gathered and processed natural gas volumes on the Elk City/Sweetwater system, which includes contributions from the Sweetwater processing facility, partially offset by a decrease in the NOARK gathering system natural gas purchases. Transportation and compression expenses increased $2.7 million to $13.5 million for the year ended December 31, 2007 due to higher NOARK and Appalachia system operating and maintenance costs as a result of increased capacity and additional well connections.

General and administrative expenses, including amounts reimbursed to affiliates, increased $38.4 million to $61.0 million for the year ended December 31, 2007 compared with $22.6 million for the prior year. This increase was mainly due to a $30.0 million increase in non-cash compensation expense related to vesting of phantom and common unit awards (see Note 14 to the consolidated financial statements in Item 8, Financial Statements and Supplementary Data) and higher costs associated with managing our business, including management time related to acquisition and capital raising opportunities.

Table of Contents

Depreciation and amortization increased to $51.0 million for the year ended December 31, 2007 compared with $23.0 million for the year ended December 31, 2006 due primarily to the depreciation associated with our Chaney Dell and Midkiff/Benedum acquired assets and our expansion capital expenditures incurred between the periods, including the Sweetwater processing facility.

Interest expense increased to $61.5 million for the year ended December 31, 2007 as compared with $24.6 million for the prior year. This $36.9 million increase was primarily due to interest associated with the $830.0 million term loan issued in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems and a $5.1 million increase in the amortization of deferred finance costs principally due to $5.0 million of accelerated amortization associated with the replacement of our previous credit facility with a new credit facility in July 2007 (see Term Loan and Credit Facility).

Minority interest expense of $3.9 million for the year ended December 31, 2007 represents Anadarko s 5% ownership interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to effect our acquisition of control of the respective systems. Minority interest expense of $0.1 million for the year ended December 31, 2006 represents Southwestern s 25% ownership interest in the net income of NOARK through May 2, 2006, the date which we acquired this remaining ownership interest.

During June 2006, we identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and first quarter of 2006, we recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively. Our management believes that the impact of these adjustments is immaterial to our prior financial statements.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash generated from operations and borrowings under our credit facility. Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and quarterly distributions to our common unitholders 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 the retention of cash and additional borrowings; and
- debt principal payments through additional borrowings as they become due or by the issuance of additional limited partner units.

We had $302.0 million outstanding under our $380.0 million senior secured credit facility at December 31, 2008 and $5.9 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $72.1 million of remaining committed capacity under the credit facility, subject to covenant limitations (see Term Loan and Credit Facility). We were in compliance with the credit facility s covenants at December 31, 2008. At December 31, 2008, we had a working capital deficit of $48.8 million compared with a $78.2 million working capital deficit at December 31, 2007. This increase in working capital was primarily due to a $95.4 million increase in the current portion of net hedge receivable, partially offset by a $15.1 million increase in accounts payable and accrued liabilities and a $37.8 million decrease in accounts receivable. We believe that we have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cashflow. We may need to 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 and sales of our assets.

Recent instability in the financial markets, as a result of recession or otherwise, has increased the cost of capital while the availability of funds from those markets has diminished significantly. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our 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 the extent required and on acceptable terms.

Cash Flows   Year Ended December 31, 2008 Compared to Year December 31, 2007

Net cash used in operating activities of $58.8 million for the year ended December 31, 2008 represented a decrease of $158.6 million from $99.8 million of net cash provided by operating activities for the prior year. The decrease was derived principally from a $198.6 million unfavorable movement in net income (loss) excluding non-cash charges, partially offset by a $40.1 million increase in cash flows from working capital changes. The decrease in net income (loss) excluding non-cash charges was principally due to the $197.6 million net unfavorable cash impact from the early termination of certain derivative instruments during the year ended December 31, 2008. The non-cash charges which impacted net income (loss) include a $378.2 million increase in non-cash derivative gains, a $70.3 million decrease in non-cash compensation expense, a $26.7 million unfavorable change in minority interest expense, and a $19.9 million non-cash gain on the extinguishment of long-term debt, partially offset by a $698.5 million increase in goodwill and other asset impairment loss and a $39.1 million increase in depreciation and amortization expense. The movement in non-cash derivative gains and losses resulted from decreases in commodity prices at December 31, 2008 compared with the prior year end and their favorable mark-to-market impact on the fair value of derivative contracts we have for future periods. The increase in depreciation and amortization principally resulted from our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007. The increase in goodwill and other asset impairment loss was due to our goodwill impairment charge of $676.9 million and a $21.6 million write-off of costs related to a pipeline expansion project during the year ended December 31, 2008. The decrease in non-cash compensation expense was principally attributable to a mark-to-market gain recognized during the year ended December 31, 2008 for certain common unit awards for which the ultimate amount to be issued was determined after the completion of our 2008 fiscal year. The mark-to-market gain was the result of a decrease in our common unit market price at December 31, 2008 when compared with the December 31, 2007 price, which was utilized in the estimate of the non-cash compensation expense for these awards.

Net cash used in investing activities was $292.9 million for the year ended December 31, 2008, a decrease of $1,731.7 million from $2,024.6 million for the prior year. This decrease was principally due to a $1,915.9 million decrease in net cash paid for acquisitions, partially offset by a $186.3 million increase in capital expenditures. Net cash paid for acquisitions of $1,884.5 million in the prior year represents the net amount paid for our acquisition of the Chaney Dell and Midkiff/Benedum systems. The $31.4 million of net cash received for acquisition in the current period principally represents the reimbursement of state sales tax initially paid for our prior year acquisition of the Chaney Dell and Midkiff/Benedum systems. See further discussion of capital expenditures under   Capital Requirements .

Net cash provided by financing activities was $341.2 million for the year ended December 31, 2008, a decrease of $1,593.9 million from $1,935.1 million for the prior year. This decrease was principally due to an $858.2 million decrease from the net proceeds of issuance of our common units, a $572.3 million decrease from the net proceeds of issuance of long-term debt, a $162.9 million increase in repayments of long-term debt, and a $107.4 million increase in cash distributions to common limited partners and the general partner, partially offset by a $130.0 million increase in borrowings under our revolving credit facility. The decrease in net proceeds of issuance of our common units and long-term debt were due to the prior year financing of our acquisition of the Chaney Dell and Midkiff/Benedum systems. The repayments of long-term debt were associated with our issuance of $250.0 million 8.75% Senior Notes in June 2008, the net proceeds of which were utilized to repay indebtedness under our senior secured term loan and revolving credit facility and our repurchase of approximately $60.0 million in face amount of our Senior Notes for an aggregate purchase price of approximately $40.1 million during the year ended December 31, 2008 (see Recent Events). The increase in net borrowings under our revolving credit facility was principally utilized to finance our capital expenditures during the period.

Cash Flows Year Ended December 31, 2007 Compared to Year December 31, 2006

Net cash provided by operating activities of $99.8 million for the year ended December 31, 2007 represented an increase of $54.8 million from $45.0 million for the prior year. The increase was derived principally from a $63.3 million increase in net income excluding non-cash charges and a $6.3 million decrease in cash flow from working capital changes. This increase in net income excluding non-cash charges was principally due to the contributions from the Chaney Dell and Midkiff/Benedum systems, which were acquired in July 2007. The non-cash charges which impacted net income include a $171.7 million favorable movement in derivative non-cash gains and losses, a $30.0 million increase in non-cash compensation expense, a $28.0 million increase in depreciation and amortization and a $5.1 million increase in amortization of deferred finance costs. The movement in derivative non-cash gains and losses resulted from commodity price movements and their unfavorable impact on derivative contracts we have for future periods. The increase in non-cash compensation expense was due to an increase in common unit awards estimated by management to be issued under incentive compensation agreements to certain key employees as a result of the acquisition of the Chaney Dell and Midkiff/Benedum systems. The increase in minority interest and depreciation and amortization resulted from our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007.

Net cash used in investing activities was $2,024.6 million for the year ended December 31, 2007, an increase of $1,920.1 million from $104.5 million for the prior year. This increase was principally due to the $1,884.5 million of net cash paid for acquisition for the year ended December 31, 2007 compared with the $30.0 million for the prior year. Net cash paid for acquisition for the year ended December 31, 2007 represents the net amount paid for our acquisition of the Chaney Dell and Midkiff/Benedum systems, while the net cash paid for the prior year comparable period represents the amount paid for our acquisition of the remaining 25% ownership interest in the NOARK system. Also affecting the change in net cash used in investing activities was a $55.9 million increase in capital expenditures, a $7.0 million decrease in cash proceeds received from the sale of assets, and a $1.5 million decrease in net cash proceeds received from APL s settlement of an insurance claim which occurred during the prior year. The decrease in cash proceeds received from the sale of assets resulted from the sale of certain gathering pipelines within the Velma system during the year ended December 31, 2006. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities was $1,935.1 million for the year ended December 31, 2007, an increase of $1,908.1 million from $27.0 million of net cash provided by financing activities for the prior year. This increase was principally due to a $1,095.4 million increase in net proceeds from the issuance of our common units, a $789.1 million increase in net proceeds from the issuance of long-term debt, a $39.0 million favorable impact regarding repayments of long-term debt, and a $21.9 million increase in capital contributions. These amounts were partially offset by a $39.9 million decrease in net proceeds from the issuance of our cumulative convertible preferred units, an $8.5 million increase in preferred unit distributions paid, and a $38.5 million net increase in borrowings under our revolving credit facility. The increase in net proceeds from the issuance of our common units, net proceeds from the issuance of our long-term debt, and capital contributions resulted from transactions undertaken during July 2007 to finance our acquisition of the Chaney Dell and Midkiff/Benedum systems.

Table of Contents

Capital Requirements

Our operations require continual investment to upgrade or enhance existing operations and to ensure compliance with safety, operational, and environmental regulations. Our capital requirements consist primarily of:

- maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and
- expansion capital expenditures to acquire complementary assets and to expand the capacity of our existing operations.

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

	Years Ended December 31,		
	2008	2007	2006
Maintenance capital expenditures	$ 6,674	$ 9,115	$ 4,649
Expansion capital expenditures	319,260	130,532	79,067
Total	$ 325,934	$ 139,647	$ 83,716

Expansion capital expenditures increased to $319.3 million for the year ended December 31, 2008 due principally to the expansion of our gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas, including the construction of a 60 MMcfd expansion of our Sweetwater processing plant. The decrease in maintenance capital expenditures for the year ended December 31, 2008 when compared with the prior year was due to fluctuations in the timing of our scheduled maintenance activity. As of December 31, 2008, we are committed to expend approximately $93.0 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Expansion capital expenditures increased to $130.5 million for the year ended December 31, 2007, due principally to expansions of the Appalachia, Velma and Elk City/Sweetwater, NOARK, Chaney Dell and Midkiff/Benedum gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. Maintenance capital expenditures the year ended December 31, 2007 increased to $9.1 million due to the additional maintenance requirements of our Chaney Dell and Midkiff/Benedum acquisition and fluctuations in the timing of scheduled maintenance activity.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash to our common unitholders and our 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 by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds 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. When our general partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our

Table of Contents

general partner if quarterly distributions to common limited partners 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. During July 2007, our general partner, holder of all of our incentive distribution rights, agreed to allocate up to $5.0 million of incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems (see Significant Acquisitions). Our general partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the general partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter. Of the $37.3 million of incentive distributions declared for the year ended December 31, 2008, the general partner received $23.5 million after the allocation of $13.8 million of its incentive distribution rights back to us.

Off Balance Sheet Arrangements

As of December 31, 2008, our off balance sheet arrangements are limited to our letters of credit outstanding of $5.9 million and our commitments to expend approximately $93.0 million on capital projects.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations and commercial commitments at December 31, 2008 (in thousands):

		Payments Due By Period			
Contractual cash obligations:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Total debt	$ 1,493,427	$	$	$ 302,000	$ 1,191,427
Interest on total debt[(1)]	469,482	71,566	143,132	138,404	116,380
Derivative-based obligations	63,594	26,008	34,904	2,682	
Operating leases	11,535	4,953	5,336	1,246	
Total contractual cash obligations	$ 2,038,038	$ 102,527	$ 183,372	$ 444,332	$ 1,307,807

(1) Based on the interest rates of our respective debt components as of December 31, 2008.

		Amount of Commitment Expiration Per Period			
Other commercial commitments:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Standby letters of credit	$ 5,925	$ 5,925	$	$	$
Other commercial commitments	93,007	93,007			
Total commercial commitments	$ 98,932	$ 98,932	$	$	$

Other commercial commitments relate to commitments for pipeline extensions, compressor station upgrades and processing facility upgrades.

Common Equity Offerings

In June 2008, we sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, we sold 1,112,000 common units to Atlas America and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. We also received a capital contribution from AHD of $5.4 million for AHD to maintain its 2.0% general partner interest in us. We utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements (see Recent Events).

In July 2007, we sold 25,568,175 common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125 billion. Of the 25,568,175 common units sold, 3,835,227 common units were purchased by AHD for $168.8 million. We also received a capital contribution from AHD of $23.1 million in order for AHD to maintain its 2.0% general partner interest in us. We utilized the net proceeds from the sale to partially fund the Chaney Dell and Midkiff/Benedum acquisitions (see Significant Acquisitions). The common units issued were subsequently registered with the Securities and Exchange Commission in November 2007.

In May 2006, we sold 500,000 common units in a public offering at a price of $41.20 per unit, yielding net proceeds of approximately $19.7 million, after underwriting commissions and other transaction costs. We utilized the net proceeds from the sale to partially repay borrowings under our credit facility made in connection with our acquisition of the remaining 25% ownership interest in NOARK.

Convertible Preferred Units

Class A Preferred Units

In March 2006, we entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units (Class A Preferred Units) representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for aggregate gross proceeds of $30.0 million. We also sold an additional 10,000 Class A Preferred Units to Sunlight Capital for $10.0 million in May 2006, pursuant to our right under the agreement to require Sunlight Capital to purchase such additional units. The Class A Preferred Units were originally entitled to receive dividends of 6.5% per annum commencing in March 2007, and paid quarterly on the same date as the distribution payment date for our common units. In April 2007, we and Sunlight Capital agreed to amend the terms of the Class A Preferred Units effective as of that date. The terms of the Class A Preferred Units were amended to entitle them to receive dividends of 6.5% per annum commencing in March 2008 and to be convertible, at Sunlight Capital s option, into common units commencing May 8, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of our common units as of the date of the notice of conversion. We may elect to pay cash rather than issue common units in satisfaction of a conversion request. We have the right to call the Class A Preferred Units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.22. If not converted into common units or redeemed prior to the second anniversary of the conversion commencement date, the Class A Preferred Units will automatically be converted into our common units in accordance with the agreement. In consideration of Sunlight Capital s consent to the amendment of the Class A Preferred Units, we issued $8.5 million of our 8.125% senior unsecured notes due 2015 to Sunlight Capital. We recorded the senior unsecured notes issued as long-term debt and a preferred unit dividend within partners capital on our consolidated balance sheet and, during the year ended December 31, 2007, reduced net income (loss) attributable to common limited partners and the general partner by $3.8 million of this amount, which was the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the Class A preferred unitholder, on our consolidated statements of operations.

In December 2008, we redeemed 10,000 of the Class A Preferred Units for $10.0 million in cash under the terms of the agreement. The redemption was classified as a reduction of Class A Preferred Equity within partners capital on our consolidated balance sheet. Our 30,000 outstanding Class A preferred limited partner units were convertible into approximately 5,263,158 common limited partner units at December 31, 2008, which is based upon the market value of our common units and subject to provisions and limitations within the agreement between the parties, with an estimated fair value of approximately $31.6 million based upon the market value of our common units as of that date.

On January 27, 2009, we and Sunlight Capital agreed to a second amendment to the Class A Preferred Units. The amendment (a) increased the dividend yield from 6.5% to 12% per annum, effective January 1, 2009,

(b) changed the conversion commencement date from May 8, 2008 to April 1, 2009, (c) changed the conversion price adjustment from $43.00 to $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of our common units, and (d) changed the call redemption price from $53.22 to $27.25. Simultaneously with the execution of the amendment, we issued Sunlight Capital $15.0 million of our 8.125% senior unsecured notes due 2015 to redeem 10,000 Class A Preferred Units. We also agreed that we will redeem an additional 10,000 Class A Preferred Units for cash at the liquidation value on April 1, 2009. If Sunlight does not exercise its conversion right on or before June 2, 2009, we will redeem the then-remaining 10,000 Class A Preferred Units for cash or one-half for cash and one-half for our common limited partner units on July 1, 2009.

Dividends previously paid and those to be paid on the Class A Preferred Units and the premium paid upon their redemption, if any, will be recognized as a reduction to our net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. If converted to common units, the Class A preferred equity amount converted will be reclassified to common unit equity within partners capital on our consolidated balance sheet.

Class B Preferred Units

In December 2008, we sold 10,000 newly-created Class B Preferred Units to AHD for cash consideration of $1,000 per Class B Preferred Unit (the Face Value). AHD has the right, before March 30, 2009, to purchase an additional 10,000 Class B Preferred Units on the same terms. We used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units will receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for our common units. The record date for the determination of holders entitled to receive distributions of the Class B Preferred Units will be the same as the record date for determination of common unit holders entitled to receive quarterly distributions. The Class B Preferred Units are convertible, at the holder s option, into common units commencing on June 30, 2009 (the Class B Preferred Unit Conversion Commencement Date), provided that the holder must request conversion of at least 2,500 Class B Preferred Units and cannot make a conversion request more than once every 30 days. The conversion price will be the lesser of (a) $7.50 (subject to adjustment for customary events such as stock splits, reverse stock splits, stock distributions and spin-offs) and (b) 95% of the average closing price of the common units for the 10 consecutive trading days immediately preceding the date of the holder s notice to us of its conversion election (the Market Price). The number of common units issuable is equal to the Face Value of the Class B Preferred Units being converted plus all accrued but unpaid distributions (the Class B Preferred Unit Liquidation Value), divided by the conversion price. Within 5 trading days of our receipt of a conversion notice, we may elect to pay the notifying holder cash rather than issue common units in satisfaction of the conversion request. If we elect to pay cash for the Class B Preferred Units, the conversion price will be the lesser of (a) $7.50 and (b) 100% of the Market Price and the cash amount will be equal to (x) if Market Price is greater than $7.50, the number of common units issuable for the Class B Preferred Units being redeemed multiplied by the Market Price or (y) if the Market Price is less than or equal to $7.50, the Class B Preferred Unit Liquidation Value. We have the right to redeem some or all of the Class B Preferred Units (but not less than 2,500 Class B Preferred Units) for an amount equal to the Class B Preferred Unit Liquidation Value being redeemed divided by the conversion price multiplied by $9.50.

The sale of the Class B Preferred Units to AHD was exempt from the registration requirements of the Securities Act of 1933. We have agreed to file, upon demand, a registration statement to cover the resale of the common units underlying the Class B Preferred Units. AHD is entitled to receive the dividends on the Class B Preferred units pro rata from the December 2008 commencement date. Dividends to be paid on the Class B Preferred Units and the premium paid upon their redemption, if any, will be recognized as a reduction to our net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. If converted to common units, the Class B preferred equity amount converted will be reclassified to common unit equity within partners capital on our consolidated balance sheet.

Our 10,000 outstanding Class B preferred limited partner units were convertible into approximately 1,754,386 common limited partner units at December 31, 2008, with an estimated fair value of approximately $10.5 million based upon the market value of our common units as of that date.

Table of Contents

Term Loan and Credit Facility

At December 31, 2008, we had a senior secured credit facility with a syndicate of banks which consisted of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at our option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding revolving credit facility borrowings at December 31, 2008 was 3.7%, and the weighted average interest rate on the outstanding term loan borrowings at December 31, 2008 was 3.0%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $5.9 million was outstanding at December 31, 2008. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet.

In June 2008, we entered into an amendment to our revolving credit facility and term loan agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to our early termination of certain derivative contracts (see Recent Events) in calculating our Consolidated EBITDA. Pursuant to this amendment, in June 2008, we repaid $122.8 million of our outstanding term loan and repaid $120.0 million of outstanding borrowings under the credit facility with proceeds from our issuance of $250.0 million of 10-year, 8.75% senior unsecured notes (see Senior Notes). Additionally, pursuant to this amendment, in June 2008 our lenders increased their commitments for our revolving credit facility by $80.0 million to $380.0 million.

Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum joint ventures, and by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are in compliance with these covenants as of December 31, 2008. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt or equity issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with entering into the credit facility, we agreed to remit an underwriting fee to the lead underwriting bank of 0.75% of the aggregate principal amount of the term loan outstanding on January 23, 2008. Since then, we and the underwriting bank agreed to extend the agreement through January 30, 2009 and reduce the underwriting fee to 0.50% of the aggregate principal amount of the term loan outstanding as of that date.

The events which constitute an event of default for our credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. The credit facility requires us to maintain a ratio of funded debt (as defined in the credit facility) to Consolidated EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.75 to 1.0. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of December 31, 2008, our ratio of funded debt to EBITDA was 4.7 to 1.0 and our interest coverage ratio was 4.0 to 1.0.

We are unable to borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement.

Senior Notes

At December 31, 2008, we had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $260.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with $0.7 million of unamortized premium received as of December 31, 2008. The 8.75% Senior Notes were issued in June 2008 in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $244.9 million, after underwriting commissions and other transaction costs. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, we may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under our credit facility.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; 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 its assets. We are in compliance with these covenants as of December 31, 2008.

In connection with the issuance of the 8.75% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If we did not meet the aforementioned deadline, the 8.75% Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that we had caused the exchange offer to be consummated. On November 21, 2008, we filed an exchange offer registration statement for the 8.75% Senior Notes with the Securities and Exchange Commission, which was declared effective on December 16, 2008. The exchange offer was consummated on January 21, 2009, thereby fulfilling all of the requirements of the 8.75% Senior Notes registration rights agreement by the specified dates.

In December 2008, we repurchased approximately $60.0 million in face amount of our Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million in face amount of our 8.125% Senior Notes and approximately $27.0 million in face amount of our 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue.

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. 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 and criminal penalties, imposition of remedial requirements, and issuance of injunctions as to future compliance or other mandatory or consensual measures. We have an ongoing environmental compliance program. However, risks of accidental leaks or spills are associated with the transportation of natural gas. 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 business. Moreover, it is possible that other developments, such as increasingly strict environmental laws and regulations and enforcement policies hereunder, could result in increased costs and liabilities to us.

Environmental laws and regulations have changed substantially and rapidly over the last 25 years, and we anticipate that there will be continuing changes. One trend in environmental regulation is to increase reporting obligations and place more restrictions and limitations on activities, such as emissions of pollutants, generation and disposal of wastes and use, storage and handling of chemical substances, that may impact human health, the environment and/or endangered species. Increasingly strict 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 charge, or that our efforts will prevent material costs, if any, from arising.

Inflation and Changes in Prices

Inflation affects the operating expenses of our operations. In addition, inflationary trends may occur if commodity prices were to increase since such an increase may cause the demand in energy equipment and services to increase, thereby increasing the costs of acquiring or obtaining such equipment and services. Increases in those expenses are not necessarily offset by increases in revenues and fees that our operations are able to charge. While we anticipate that inflation will affect our future operating costs, we cannot predict the timing or amounts of any such effects.

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 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 . The critical accounting policies and estimates we have identified are discussed below.

Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets. The cost of properties, plants 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 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. 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

Table of Contents

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 Forward Looking Statements elsewhere in this document.

As discussed below, we recognized an impairment of goodwill at December 31, 2008. We believe this impairment of goodwill was an event that warranted assessment of our long-lived assets for possible impairment. We evaluated all of our long-lived assets, including intangible customer relationships, at December 31, 2008, and determined that the undiscounted estimated future net cash flows related to these assets continued to support the recorded values.

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. Under the principles of SFAS No. 142, an impairment loss should be recognized if the carrying value of an entity s reporting units exceeds its estimated fair value. Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of these reporting units. 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 assets. A key component of these fair value determinations is a reconciliation of the sum of these net present value calculations to our market capitalization. The principles of SFAS No. 142 and its interpretations acknowledge that 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 s individual equity securities. In most industries, including ours, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above net present value calculations have been determined, we also add a control premium to the calculations. This control premium is judgmental and is based on observed acquisitions in our industry. The resultant fair values calculated for the reporting units are then compared to observable metrics on large mergers and acquisitions in our industry to determine whether those valuations appear reasonable in management s judgment.

As a result of our impairment evaluation at December 31, 2008, we recognized a $676.9 million non-cash impairment charge within our consolidated statements of operations for the year ended December 31, 2008. The goodwill impairment resulted from the reduction in our estimated fair value of reporting units in comparison to their carrying amounts at December 31, 2008. Our estimated fair value of the reporting units was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. 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, 2007 and 2006. See Goodwill in Note 2 under Item 8, Financial Statements and Supplementary Data for information regarding our impairment of goodwill and other assets.

Fair Value of Financial Instruments

We adopted the provisions of SFAS No. 157 at January 1, 2008. SFAS No. 157 establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. SFAS No. 157 (1) creates a single definition of fair value, (2) establishes a hierarchy for measuring fair value, and (3) expands disclosure requirements about items measured at fair value. SFAS No. 157 does not change existing accounting rules governing what can or what must be recognized and reported at fair value in our financial statements, or disclosed at fair value in our notes to the financial statements. As a result, we will not be required to recognize any new assets or liabilities at fair value.

SFAS No. 157 s 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 assumption 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 the fair value methodology outlined in SFAS No. 157 to value the assets and liabilities for our respective outstanding derivative contracts (see Note 10 under Item 8, Financial Statements and Supplementary Data). All of our derivative contracts are defined as Level 2, with the exception of our NGL fixed price swaps and crude oil options. Our Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. Our interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for our NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of natural gas, crude oil, and propane prices, and therefore are defined as Level 3. Valuations for our crude oil options (including those associated with NGL sales) are based on forward price curves developed by the related financial institution based upon current quoted prices for crude oil futures, and therefore are defined as Level 3.

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 oil and natural gas 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 our 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 periodical use of derivative instruments. 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, 2008. Only the potential impact of hypothetical assumptions is 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 to our commodity and interest-rate derivative contracts are banking institutions who also participate in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At December 31, 2008, we had a $380.0 million senior secured revolving credit facility ($302.0 million outstanding). We also had $707.2 million outstanding under our senior secured term loan at December 31, 2008. The weighted average interest rate for the revolving credit facility borrowings was 3.7% at December 31, 2008, and the weighted average interest rate for the term loan borrowings was 3.0% at December 31, 2008.

At December 31, 2008, we have interest rate derivative contracts having aggregate notional principal amounts of $450.0 million. Under the terms of these agreements, we will pay weighted average interest rates of 3.02%, plus the applicable margin as defined under the terms of our revolving credit facility, and will receive LIBOR, plus the applicable margin, on the notional principal amounts. These derivatives effectively convert $450.0 million of our floating rate debt under the term loan and revolving credit facility to fixed-rate debt. The interest rate swap agreements are effective as of December 31, 2008 and expire during periods ranging from January 30, 2010 through April 30, 2010.

Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by $5.6 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based on estimated unhedged market prices of $0.76 per gallon, $6.50 per mmbtu and $55.00 per barrel for NGLs, natural gas and condensate, respectively, would change our gross margin for the twelve-month period ending December 31, 2009 by approximately $25.3 million.

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price and interest rate risk management activities. We enter into financial swap and option instruments to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. We also enter into financial swap instruments to hedge certain portions of our floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. Under 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. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period.

We apply the provisions of SFAS No. 133 to our derivative instruments. We formally document all relationships between hedging instruments and the items being hedged, including our risk management objective and strategy for undertaking the hedging transactions. This includes matching derivative contracts to the forecasted transactions. Under SFAS No. 133, we can assess, 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, we will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by us through the utilization of market data, will be recognized within other income (loss) in our consolidated statements of operations. For derivatives previously qualifying as hedges, we recognized the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassified the portion relating to commodity derivatives to natural gas and liquids revenue and the portion relating to interest rate derivatives to interest expense within our consolidated statements of operations as the underlying transactions were settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within other income (loss) in our consolidated statements of operations as they occur.

On July 1, 2008, we elected to discontinue hedge accounting for our existing commodity derivatives which were qualified as hedges under SFAS No. 133. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss) in our consolidated statements of operations. The fair value of these commodity derivative instruments at June 30, 2008, which was recognized in accumulated other comprehensive loss within partners capital on our consolidated balance sheet, will be reclassified to our consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings.

Table of Contents

During the year ended December 31, 2008, we made net payments of $274.0 million related to the early termination of derivative contracts that were principally entered into as proxy hedges for the prices received on the ethane and propane portion of our NGL equity volume. Substantially all of these derivative contracts were put into place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. During the years ended December 31, 2008, 2007 and 2006, we recognized the following derivative activity related to the termination of these derivative instruments within our consolidated statement of operations (amounts in thousands):

	Early termination of derivative contracts for the Years Ended December 31,		
	2008	**2007**	**2006**
Net cash derivative expense included within other income (loss), net	$ (199,964)	$	$
Net cash derivative income included within natural gas and liquids revenue	2,322		
Net non-cash derivative expense included within other income (loss), net	(39,218)		
Net non-cash derivative expense included within natural gas and liquids	(32,389)		

In addition, at December 31, 2008, $37.3 million will be reclassified from accumulated other comprehensive loss within partner s capital on our consolidated balance sheet and recognized as non-cash derivative expense during the period beginning on January 1, 2009 and ending on December 31, 2009, the remaining period for which the derivatives were originally scheduled to be settled, as a result of the early termination of certain derivatives that were classified as cash flow hedges in accordance with SFAS No. 133 at the date of termination.

The following table summarizes our derivative activity for the periods indicated (amounts in thousands):

	Years Ended December 31,		
	2008	**2007**	**2006**
Loss from cash and non-cash settlement of qualifying hedge instruments(1)	$ (105,015)	$ (49,393)	$ (13,945)
Gain (loss) from change in market value of non- qualifying derivatives(2)	140,144	(153,393)	4,206
Loss from de-designation of cash flow derivatives(2)		(12,611)	
Gain (loss) from change in market value of ineffective portion of qualifying derivatives(2)	47,229	(3,450)	1,520
Loss from cash and non-cash settlement of non-qualifying derivatives(2)	(250,853)	(10,158)	
Loss from cash settlement of interest rate derivatives(3)	(1,226)		

(1) Included within natural gas and liquids revenue on our consolidated statements of operations.
(2) Included within other income (loss), net on our consolidated statements of operations.
(3) Included within interest expense on our consolidated statements of operations.

Table of Contents

As of December 31, 2008, we had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Interest Fixed-Rate Swap

Term	Notional Amount	Type		Contract Period Ended December 31,	Fair Value Liability(1) (in thousands)
January 2008 - January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	2009	$ (4,130)
				2010	(249)
					$ (4,379)
April 2008 - April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2009	$ (5,835)
				2010	(1,513)
					$ (7,348)

Natural Gas Liquids Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Asset(2) (in thousands)
2009	8,568,000	$ 0.746	$ 1,509

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)(3) (in thousands)	Option Type
2009	1,056,000	56,634,732	$ 80.00	$ 29,006	Puts purchased
2009	304,200	27,085,968	$ 126.05	(22,774)	Puts sold(4)
2009	304,200	27,085,968	$ 143.00	44	Calls purchased(4)
2009	2,121,600	114,072,336	$ 81.01	(1,080)	Calls sold
2010	3,127,500	202,370,490	$ 81.09	(17,740)	Calls sold
2010	714,000	45,415,440	$ 120.00	1,279	Calls purchased(4)
2011	606,000	32,578,560	$ 95.56	(3,123)	Calls sold
2011	252,000	13,547,520	$ 120.00	646	Calls purchased(4)
2012	450,000	24,192,000	$ 97.10	(2,733)	Calls sold
2012	180,000	9,676,800	$ 120.00	607	Calls purchased(4)
				$ (15,868)	

Natural Gas Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)[5]	Average Fixed Price (per mmbtu) [5]	Fair Value Asset [3] (in thousands)
2009	5,247,000	$ 8.611	$ 14,326
2010	4,560,000	$ 8.526	6,461
2011	2,160,000	$ 8.270	2,072
2012	1,560,000	$ 8.250	1,596
			$ 24,455

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)[5]	Average Fixed Price (per mmbtu)[5]	Fair Value Asset/(Liability)[3] (in thousands)
2009	5,724,000	$ (0.558)	$ (1,220)
2010	4,560,000	$ (0.622)	1,106
2011	2,160,000	$ (0.664)	367
2012	1,560,000	$ (0.601)	316
			$ 569

Table of Contents

Natural Gas Purchases Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Liability(3) (in thousands)
2009	14,267,000	$ 8.680	$ (36,734)
2010	8,940,000	$ 8.580	(13,403)
2011	2,160,000	$ 8.270	(2,072)
2012	1,560,000	$ 8.250	(1,596)
			$ (53,805)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Liability(3) (in thousands)
2009	15,564,000	$ (0.654)	$ (9,201)
2010	8,940,000	$ (0.600)	(3,720)
2011	2,160,000	$ (0.700)	(423)
2012	1,560,000	$ (0.610)	(383)
			$ (13,727)

Ethane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Asset(2) (in thousands)	Option Type
2009	14,049,000	$ 0.6948	$ 3,234	Puts purchased

Propane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Asset(2) (in thousands)	Option Type
2009	14,490,000	$ 1.4154	$ 9,083	Puts purchased

Isobutane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(2) (in thousands)	Option Type
2009	126,000	$ 0.7500	$ (3)	Puts purchased

Normal Butane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability[2] (in thousands)	Option Type
2009	113,400	$ 0.7350	$ (3)	Puts purchased

66

Table of Contents

Natural Gasoline Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Asset(2) (in thousands)	Option Type
2009	126,000	$ 0.9650	$ 5	Puts purchased

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Asset(3) (in thousands)
2009	33,000	$ 62.700	$ 252

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability)(3) (in thousands)	Option Type
2009	105,000	$ 90.000	$ 3,635	Puts purchased
2009	306,000	$ 80.017	(6,122)	Calls sold
2010	234,000	$ 83.027	(4,046)	Calls sold
2011	72,000	$ 87.296	(546)	Calls sold
2012	48,000	$ 83.944	(489)	Calls sold
			$ (7,568)	
		Total net liability	$ (63,594)	

(1) Fair value based on independent, third-party statements, supported by observable levels at which transactions are executed in the marketplace.

(2) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas, light crude and propane prices.

(3) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

(4) Puts sold and calls purchased for 2009 represent costless collars entered into by us as offsetting positions for the calls sold related to ethane and propane production. In addition, calls were purchased for 2010 through 2012 to offset positions for calls sold. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

(5) Mmbtu represents million British Thermal Units.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited the accompanying consolidated balance sheets of Atlas Pipeline Partners, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), partners capital, and cash flows for each of the three years in the period ended December 31, 2008. 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 Pipeline Partners, L.P. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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), Atlas Pipeline Partners, L.P. s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 27, 2009 expressed an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 27, 2009

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,520	$ 11,980
Accounts receivable - affiliates	537	3,334
Accounts receivable	112,365	147,360
Current portion of derivative asset	44,961	
Prepaid expenses and other	11,997	14,749
Total current assets	171,380	177,423
Property, plant and equipment, net	2,022,937	1,748,661
Intangible assets, net	193,647	219,203
Goodwill		709,283
Minority interest	32,337	2,163
Other assets, net	25,232	20,881
	$ 2,445,533	$ 2,877,614
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$	$ 34
Accounts payable	70,691	20,399
Accrued liabilities	21,701	43,487
Current portion of derivative liability	60,396	110,867
Accrued producer liabilities	67,406	80,829
Total current liabilities	220,194	255,616
Long-term derivative liability	48,159	118,646
Long-term debt, less current portion	1,493,427	1,229,392
Other long-term liability	574	
Commitments and contingencies		
Partners capital:		
Class A preferred limited partner s interest	27,853	37,076
Class B preferred limited partner s interest	10,007	
Common limited partners interests	735,742	1,269,521
General partner s interest	14,521	29,413
Accumulated other comprehensive loss	(104,944)	(62,050)
Total partners capital	683,179	1,273,960
	$ 2,445,533	$ 2,877,614

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Years Ended December 31,		
	2008	**2007**	**2006**
Revenue:			
Natural gas and liquids	$ 1,370,000	$ 761,118	$ 391,356
Transportation, compression and other fees affiliates	43,293	33,169	30,189
Transportation, compression and other fees third parties	56,416	48,616	30,735
Other income (loss), net	(55,519)	(174,103)	12,412
Total revenue and other income (loss), net	1,414,190	668,800	464,692
Costs and expenses:			
Natural gas and liquids	1,086,142	587,524	334,299
Plant operating	60,835	34,667	15,722
Transportation and compression	17,886	13,484	10,753
General and administrative	(1,070)	55,047	20,250
Compensation reimbursement affiliates	1,487	5,939	2,319
Depreciation and amortization	90,124	50,982	22,994
Interest	84,843	61,526	24,572
Goodwill and other asset impairment loss	698,508		
Gain on early extinguishment of debt	(19,867)		
Minority interests	(22,781)	3,940	118
Total costs and expenses	1,996,107	813,109	431,027
Net income (loss)	(581,917)	(144,309)	33,665
Preferred unit dividend effect		(3,756)	
Preferred unit dividends	(1,769)		
Preferred unit imputed dividend cost	(505)	(2,494)	(1,898)
Net income (loss) attributable to common limited partners and the general partner	$ (584,191)	$ (150,559)	$ 31,767
Allocation of net income (loss) attributable to common limited partners and the general partner:			
Common limited partners interest	$ (664,119)	$ (163,071)	$ 16,558
General partner s interest	79,928	12,512	15,209
Net income (loss) attributable to common limited partners and the general partner	$ (584,191)	$ (150,559)	$ 31,767
Net income (loss) attributable to common limited partners per unit:			
Basic	$ (15.62)	$ (6.75)	$ 1.29
Diluted	$ (15.62)	$ (6.75)	$ 1.27
Weighted average common limited partner units outstanding:			

Basic	42,513	24,171	12,884
Diluted	42,513	24,171	13,053

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

	Years Ended December 31,		
	2008	**2007**	**2006**
Net income (loss)	$ (581,917)	$ (144,309)	$ 33,665
Preferred unit dividend effect		(3,756)	
Preferred unit dividends	(1,769)		
Preferred unit imputed dividend cost	(505)	(2,494)	(1,898)
Net income (loss) attributable to common limited partners and the general partner	(584,191)	(150,559)	31,767
Other comprehensive income (loss):			
Changes in fair value of derivative instruments accounted for as hedges	(97,435)	(101,968)	(5,956)
Reclassification adjustment to earnings for de-designation of cash flow hedges		12,611	
Add: adjustment for realized losses reclassified to net income (loss)	54,541	49,393	13,945
Total other comprehensive income (loss)	(42,894)	(39,964)	7,989
Comprehensive income (loss)	$ (627,085)	$ (190,523)	$ 39,756

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(in thousands, except unit data)

	Number of Limited Partner Units			Class A Preferred Limited Partner	Class B Preferred Limited Partner	Common Limited Partner	General Partner	Accumulated Other Comprehensive Income (Loss)	Total Partners Capital
	Class A Preferred	Class B Preferred	Common						
Balance at January 1, 2006			12,549,266	$	$	$ 349,491	$ 10,094	$ (30,075)	$ 329,510
Issuance of common units			500,000			19,704			19,704
Issuance of Class A cumulative convertible preferred limited partner units	40,000			37,483					37,483
Class A preferred dividend discount						2,350	48		2,398
General partner capital contribution							1,206		1,206
Unissued common units under incentive plans						6,315			6,315
Issuance of units under incentive plans			31,152						
Distributions paid to common limited partners and the general partner						(43,194)	(15,523)		(58,717)
Distribution equivalent rights paid on unissued units under incentive plans						(419)			(419)
Other comprehensive income								7,989	7,989
Net income				1,898		16,558	15,209		33,665
Balance at December 31, 2006	40,000		13,080,418	39,381		350,805	11,034	(22,086)	379,134
Issuance of common units			25,568,175			1,115,149			1,115,149
General partner capital contribution							23,076206		23,076 37,483
Class A preferred unit dividend				(8,524)					(8,524)
Cost incurred related to issuance of Class A preferred dividend				(31)					(31)
Unissued common units under incentive plans						36,346			36,346
Issuance of units under incentive plans			109,988			(40)			(40)
						(69,084)	(17,209)		(86,293)

Distributions paid to common limited partners and the general partner									
Distribution equivalent rights paid on unissued units under incentive plans						(584)			(584)
Other comprehensive loss								(39,964)	(39,964)
Net income (loss)				6,250		(163,071)	12,512		(144,309)
Balance at December 31, 2007	40,000		38,758,581	37,076		1,269,521	29,413	(62,050)	1,273,960
Issuance of common units			7,140,000			256,928			256,928
Redemption of Class A cumulative convertible preferred limited partner units	(10,000)			(10,053)					(10,053)
Issuance of Class B cumulative convertible preferred limited partner units		10,000			10,000				10,000
General partner capital contribution							5,452		5,452
Class A preferred unit dividends				(1,437)					(1,437)
Unissued common units under incentive plans						(34,010)			(34,010)
Issuance of units under incentive plans			56,227						
Distributions paid to common limited partners and the general partner						(160,702)	(31,602)		(192,304)
Distribution equivalent rights paid on unissued units under incentive plans						(546)			(546)
Other comprehensive loss								(42,894)	(42,894)
Net income (loss)				2,267	7	(595,449)	11,258		(581,917)
Balance at December 31, 2008	30,000	10,000	45,954,808	$ 27,853	$ 10,007	$ 735,742	$ 14,521	$ (104,944)	$ 683,179

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31,		
	2008	**2007**	**2006**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (581,917)	$ (144,309)	$ 33,665
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	90,124	50,982	22,994
Goodwill and other asset impairment loss	698,508		
Gain on early extinguishment of debt	(19,867)		
Non-cash loss (gain) on derivative value, net	(208,813)	169,424	(2,316)
Non-cash compensation expense (income)	(34,010)	36,306	6,315
Loss (gain) on asset sales and dispositions		805	(2,719)
Gain on insurance claim settlement			(2,921)
Amortization of deferred finance costs	5,946	7,380	2,298
Minority interests	(22,781)	3,940	118
Net distributions paid to minority interest holders	(7,393)	(6,103)	
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable and prepaid expenses and other	34,511	(96,306)	944
Accounts payable and accrued liabilities	(15,766)	73,383	(10,397)
Accounts payable and accounts receivable affiliates	2,700	4,267	(2,952)
Net cash provided by (used in) operating activities	(58,758)	99,769	45,029
CASH FLOWS FROM INVESTING ACTIVITIES:			
Net cash received (paid) for acquisitions	31,429	(1,884,458)	(30,000)
Capital expenditures	(325,934)	(139,647)	(83,716)
Proceeds from insurance claim settlement			1,522
Proceeds from sales of assets		553	7,540
Other	1,561	(1,091)	155
Net cash used in investing activities	(292,944)	(2,024,643)	(104,499)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from issuance of debt	244,854	817,131	36,582
Repayment of debt	(162,938)		(39,019)
Borrowings under credit facility	787,400	320,500	81,000
Repayments under credit facility	(590,400)	(253,500)	(52,500)
Net proceeds from issuance of common limited partner units	256,928	1,115,149	19,704
Net proceeds from issuance of Class A preferred limited partner units			39,881
Redemption of Class A preferred limited partner units	(10,053)		
Net proceeds from issuance of Class B preferred limited partner units	10,000		
General partner capital contributions	5,452	23,076	1,206
Distributions paid to common limited partners , the general partner and preferred limited partner	(193,741)	(86,293)	(58,717)
Other	(6,260)	(1,004)	(1,109)
Net cash provided by financing activities	341,242	1,935,059	27,028

Net change in cash and cash equivalents	(10,460)	10,185	(32,442)
Cash and cash equivalents, beginning of year	11,980	1,795	34,237
Cash and cash equivalents, end of year	$ 1,520	$ 11,980	$ 1,795

See accompanying notes to consolidated financial statements

NOTE 1 NATURE OF OPERATIONS

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the transmission, gathering and processing of natural gas. The Partnership s operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 2% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 5,754,253 common limited partner units in the Partnership and 10,000, $1,000 par value cumulative convertible preferred limited partner units (see Note 4). At December 31, 2008, the Partnership had 45,954,808 common limited partnership units, including the 5,754,253 common units held by the General Partner, and 40,000, $1,000 par value cumulative convertible preferred limited partnership units outstanding, including the 10,000 cumulative convertible preferred units held by the General Partner (see Note 4).

The Partnership s General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas America, Inc. and its affiliates (Atlas America), a publicly-traded company (NASDAQ: ATLS) which owns a 64.4% ownership interest in AHD at December 31, 2008, also owns 1,112,000 of the Partnership s common limited partnership units, representing a 2.1% ownership interest in the Partnership, and a 48.3% ownership interest in Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a publicly-traded company (NYSE: ATN). Substantially all of the natural gas the Partnership transports in the Appalachian basin is derived from wells operated by Atlas Energy.

Certain amounts in the prior years consolidated financial statements have been reclassified to conform to the current year presentation. During June 2006, the Partnership identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and the first quarter of 2006, the Partnership recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005 and first quarter of 2006, respectively.

In August 2006, the Partnership sustained fire damage to a compressor station within the Velma region of its Mid-Continent segment. The Partnership maintains property damage and business interruption insurance for all of its assets and operating activities. During the fourth quarter of 2006, the Partnership received a $1.5 million partial settlement from its insurance providers related to this incident and reached a final settlement for an additional $2.6 million of insurance proceeds received during the first quarter of 2007. At December 31, 2006, the Partnership recorded the additional $2.6 million in prepaid expenses and other within its consolidated balance sheet and other income (loss), net within its consolidated statements of operations for the insurance proceeds settlement amount.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Minority Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership s wholly-owned and majority-owned subsidiaries. The General Partner s interest in the Operating Partnership is reported as part of its overall 2% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

Table of Contents

The consolidated financial statements also include the operations of the Chaney Dell natural gas gathering system and processing plants located in Oklahoma (Chaney Dell system) and the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (Midkiff/Benedum system). In July 2007, the Partnership acquired control of Anadarko Petroleum Corporation s (NYSE: APC) (Anadarko) 100% interest in the Chaney Dell system and its 72.8% undivided joint venture interest in the Midkiff/Benedum system (see Note 8). The transaction was effected by the formation of two joint venture companies which own the respective systems, of which the Partnership has a 95% interest and Anadarko has a 5% interest in each. The Partnership consolidates 100% of these joint ventures. The Partnership reflects Anadarko s 5% interest in the net income of these joint ventures as minority interest on its statements of operations. The Partnership also reflects Anadarko s investment in the net assets of the joint ventures as minority interest on its consolidated balance sheet. In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems, the joint ventures issued cash to Anadarko of $1.9 billion in return for a note receivable. This note receivable is reflected within minority interest on the Partnership s consolidated balance sheet.

The Midkiff/Benedum joint venture has a 72.8% undivided joint venture interest in the Midkiff/Benedum system, of which the remaining 27.2% interest is owned by Pioneer Natural Resources Company (NYSE: PXD) (Pioneer). Due to the Midkiff/Benedum system s status as an undivided joint venture, the Midkiff/Benedum joint venture proportionally consolidates its 72.8% ownership interest in the assets and liabilities and operating results of the Midkiff/Benedum system.

The consolidated financial statements also include the financial statements of NOARK Pipeline System, Limited Partnership (NOARK), an entity in which the Partnership currently owns a 100% ownership interest (see Note 8). On May 2, 2006, the Partnership acquired the remaining 25% ownership interest in NOARK from Southwestern Energy Pipeline Company (Southwestern), a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Prior to this transaction, the Partnership owned a 75% ownership interest in NOARK, which it had acquired in October 2005 from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE). In connection with the acquisition of the remaining 25% ownership interest, Southwestern assumed liability for $39.0 million in principal amount outstanding of NOARK s 7.15% notes due in 2018, which had been presented as long-term debt on the Partnership s consolidated balance sheet prior to the acquisition of the remaining 25% ownership interest. Subsequent to the acquisition of the remaining 25% ownership interest in NOARK, the Partnership consolidates 100% of NOARK s financial statements. The minority interest expense reflected on the Partnership s consolidated statements of operations for the year ended December 31, 2006 represents Southwestern s interest in NOARK s net income prior to the May 2, 2006 acquisition.

Use of Estimates

The preparation of the Partnership s consolidated financial statements in conformity with accounting principles generally accepted in the United States 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 expense during the reporting periods. The Partnership s consolidated financial statements are based on a number of significant estimates, including depreciation and amortization, asset impairment, the fair value of derivative instruments, the probability of forecasted transactions, the allocation of purchase price to the fair value of assets acquired and other items. 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

In evaluating the realizability of its accounts receivable, the Partnership performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by the Partnership s review of its customers credit information. The Partnership extends credit on an unsecured basis to many of its customers. At December 31, 2008 and 2007, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

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. 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. Maintenance and repairs are expensed as incurred. Major renewals and improvements that extend the useful lives of property are capitalized.

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or 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.

As discussed below, the Partnership recognized an impairment of goodwill at December 31, 2008. The Partnership believes this impairment of goodwill was an event that warranted assessment of its long-lived assets for possible impairment. The Partnership evaluated all of its long-lived assets, including intangible customer relationships, at December 31, 2008, and determined that the undiscounted estimated future net cash flows related to these assets continued to support the recorded values.

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 rate used to capitalize interest on borrowed funds was 6.3%, 8.0% and 8.1% for the years ended December 31, 2008, 2007 and 2006, respectively, and the amount of interest capitalized was $8.9 million, $3.3 million and $2.6 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Fair Value of Financial Instruments

For the Partnership s cash and cash equivalents, accounts receivables and accounts payables, the carrying amounts of these financial instruments approximate fair values because of their short maturities and are represented in the Partnership s consolidated balance sheets. For further information with regard to the Partnership s financial instruments, see Recently Adopted Accounting Standards and Note 10.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates. The Partnership applies the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133) to its derivative instruments. SFAS No. 133 requires each derivative instrument to be recorded in the balance sheet as either an asset or liability measured 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.

Table of Contents

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions (see Note 8). The following table reflects the components of intangible assets being amortized at December 31, 2008 and 2007 (in thousands):

	December 31, 2008	December 31, 2007	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,810	$ 12,810	8
Customer relationships	222,572	222,572	7-20
	$ 235,382	$ 235,382	
Accumulated Amortization:			
Customer contracts	$ (5,806)	$ (4,215)	
Customer relationships	(35,929)	(11,964)	
	$ (41,735)	$ (16,179)	
Net Carrying Amount:			
Customer contracts	$ 7,004	$ 8,595	
Customer relationships	186,643	210,608	
	$ 193,647	$ 219,203	

The Partnership recorded its initial purchase price allocation for the Chaney Dell and Midkiff/Benedum acquisition on July 27, 2007. During the fourth quarter of 2007, the Partnership adjusted its preliminary purchase price allocation by increasing the estimated amount allocated to customer contracts and customer relationships and reducing amounts initially allocated to property, plant and equipment (see Note 6 and Note 8).

SFAS No. 142, Goodwill and Other Intangible Assets (SFAS No. 142) requires that intangible assets with finite useful lives be amortized over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition. Amortization expense on intangible assets was $25.6 million, $12.1 million and $2.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2009 - $25.6 million; 2010 - $25.6 million; 2011 - $25.6 million; 2012 - $25.6 million; 2013 - $24.5 million.

Goodwill

The changes in the carrying amount of goodwill for the years ended December 31, 2008, 2007 and 2006 were as follows (in thousands):

	Years Ended December 31, 2008	2007	2006
Balance, beginning of year	$ 709,283	$ 63,441	$ 111,446
Goodwill acquired (preliminary allocation) remaining 25% interest in NOARK acquisition			30,195

Reduction in minority interest deficit acquired			(118)
Purchase price allocation adjustment	NOARK		(78,082)
Purchase price allocation adjustment	Chaney Dell and Midkiff/Benedum acquisition	645,842	

Table of Contents

Post-closing purchase price adjustment with seller and purchase price allocation adjustment - Chaney Dell and Midkiff/Benedum acquisition	(2,217)		
Recovery of state sales tax initially paid on transaction Chaney Dell and Midkiff/ Benedum acquisition	(30,206)		
Impairment loss	(676,860)		
Balance, end of year	$	$ 709,283	$ 63,441

The Partnership tests its goodwill for impairment at each year end under the principles of SFAS No. 142 by comparing reporting unit estimated fair values to carrying values. Because quoted market prices for the Partnership s reporting units are not available, management must apply judgment in determining the estimated fair value of these reporting units. 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 assets. A key component of these fair value determinations is a reconciliation of the sum of these net present value calculations to the Partnership s market capitalization. The principles of SFAS No. 142 and its interpretations acknowledge that 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 s individual equity securities. 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 net present value calculations have been determined, the Partnership also adds a control premium to the calculations. This control premium is judgmental and is based on observed acquisitions in The Partnership s industry. The resultant fair values calculated for the reporting units are then 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.

As a result of its impairment evaluation at December 31, 2008, the Partnership recognized a $676.9 million non-cash impairment charge within its consolidated statements of operations for the year ended December 31, 2008. The goodwill impairment resulted from the reduction in the Partnership s estimated fair value of reporting units in comparison to their carrying amounts at December 31, 2008. The Partnership s estimated fair value of its reporting units was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. 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 the Partnership during the years ended December 31, 2007 and 2006.

The Partnership had adjusted its preliminary purchase price allocation for the acquisition of its Chaney Dell and Midkiff/Benedum systems after its July 2007 acquisition date by adjusting the estimated amounts allocated to goodwill, intangible assets and property, plant and equipment. Also, in April 2008, the Partnership received a $30.2 million cash reimbursement for sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems in July 2007. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement of the sales tax paid in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition (see Note 8).

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 (loss) 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 Financial Accounting Standards Board s (FASB) FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes , an Interpretation of FASB Statement No. 109 requires the evaluation of 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 as part of its income tax expense, when and if they become applicable.

The Partnership files income tax returns in the U.S. federal and various state jurisdictions. With limited exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2005.

Stock-Based Compensation

The Partnership applies the provisions of SFAS No. 123(R), Share-Based Payment, as revised (SFAS No. 123(R)) to its share-based payments. Generally, the approach to accounting for share-based payments in SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

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 unitholder s interests, by the weighted average number of common limited partner units outstanding during the period. The general partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 5), with a priority allocation of net income to the general partner s incentive distributions in accordance with the partnership agreement, and the remaining net income or loss allocated with respect to the general partner s and limited partners ownership interests. Diluted net income attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of phantom unit awards, as calculated by the treasury stock method, and the dilutive effect of convertible securities. Phantom units consist of common units issuable under the terms of the Partnership s long-term incentive plan and incentive compensation agreements (see Note 14).

The Partnership presents net income (loss) per unit under the Emerging Issue Task Force s (EITF) EITF Issue No. 03-6, Participating Securities and the Two-Class Method under FASB Statement No. 128 (EITF No. 03-6), which addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder of those securities to participate in dividends and earnings of the entity when, and if, the entity declares dividends on its common stock. In quarterly accounting periods where net income does not exceed the Partnership s aggregate cash distributions to its partners, EITF No. 03-6 does not have any impact on the Partnership s net income (loss) per common limited partner unit calculation as net income (loss) is allocated to its partners with a priority allocation to actual incentive distributions paid to the general partner for the quarterly period, with the remaining net income (loss) allocated with respect to relative ownership interests. However, EITF No. 03-6 provides that if the Partnership has net income which exceeds the aggregate cash distributions to its partners during a quarterly period, it is required to present net income per common unit as if all of the earnings for the quarterly period were distributed in a manner consistent with the partnership agreement, regardless of whether those earnings would actually be distributed during a quarterly period from an economic probability standpoint. The allocation of net income for net income per common limited partner unit purposes under EITF No. 03-06 will result in an increased allocation of net income to the general partner s incentive distributions and a reduction of net income allocated to common limited partners. The following is a reconciliation of net income (loss) allocated to the general partner and common limited partners for purposes of calculating net income (loss) per common limited partner unit (in thousands, except per unit data):

	Years Ended December 31,		
	2008	**2007**	**2006**
Net income (loss)	$ (581,917)	$ (144,309)	$ 33,665
Preferred unit dividend effect		(3,756)	
Preferred unit dividends	(1,769)		
Preferred unit imputed dividend cost	(505)	(2,494)	(1,898)
Net income (loss) attributable to common limited partners and the general partner	(584,191)	(150,559)	31,767
Less:			
General partner s actual cash incentive distributions declared	23,472	15,857	14,869
Additional net income attributable to the general partner s incentive distributions under EITF 03-6	70,079		
General partner s 2% ownership interest	(13,623)	(3,345)	340
Net income (loss) attributable to the general partner s ownership interests	79,928	12,512	15,209
Net income (loss) attributable to the common limited partners	$ (664,119)	$ (163,071)	$ 16,558

While the Partnership s net income (loss) is allocated to the general partner and common limited partners in accordance with the provisions of EITF 03-6, the Partnership s net income (loss) for partners capital purposes is allocated to the general partner and the common limited partners in accordance with their respective ownership interests after giving effect to any special income allocations, including actual incentive distributions declared to the general partner for the respective quarter. On January 1, 2009, the Partnership will adopt EITF No. 07-4, Application of the Two-Class Method Under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships. The Partnership expects the adoption of EITF No. 07-4 will impact its presentation of earnings per unit (see Recently Issued Accounting Standards).

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

	Years Ended December 31,		
	2008	**2007**	**2006**
Weighted average common limited partner units - basic	42,513	24,171	12,884
Add effect of dilutive unit incentive awards[(1)]			169
Add effect of dilutive convertible preferred limited partner units[(1)]			
Weighted average common limited partner units - diluted	42,513	24,171	13,053

(1) For the years ended December 31, 2008 and 2007, approximately 901,000 and 524,000 phantom 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. For the years ended December 31, 2008, 2007 and 2006, potential common limited partner units issuable upon conversion of the Partnership s Class A and Class B cumulative convertible preferred limited partner units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive (see Note 4 for additional information regarding the conversion features of the preferred limited partner units).

Table of Contents

Environmental Matters

The Partnership is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Partnership has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. The Partnership accounts for environmental contingencies in accordance with SFAS No. 5, Accounting for Contingencies. 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 maintains insurance which may cover in whole or in part certain environmental expenditures. At December 31, 2008 and 2007, the Partnership had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Segment Information

The Partnership has two reportable segments: natural gas transmission, gathering and processing located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee, and transmission, gathering and processing located in the Mid-Continent area (Mid-Continent) of primarily Oklahoma, northern and western Texas, the Texas Panhandle, Arkansas, southern Kansas and southeastern Missouri. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates. Mid-Continent revenues are derived from the gathering and transportation of natural gas and the sale of residue gas and NGLs to purchasers at the tailgate of the processing plants.

Revenue Recognition

Revenue in the Partnership s Appalachia segment is principally recognized at the time the natural gas is transported through its gathering systems. Under the terms of its natural gas gathering agreements with Atlas Energy and its affiliates, the Partnership receives fees for gathering natural gas from wells owned by Atlas Energy and by drilling investment partnerships sponsored by Atlas Energy. The fees received for the gathering services under the Atlas Energy agreements are generally the greater of 16% of the gross sales price for natural gas produced from the wells, or $0.35 to $0.40 per thousand cubic feet (mcf), depending on the ownership of the well. Substantially all natural gas gathering revenue in the Appalachia segment is derived from these agreements. Fees for transportation services provided to independent third parties whose wells are connected to the Partnership s Appalachia gathering systems are at separately negotiated prices.

The Partnership s Mid-Continent segment revenue primarily consists of the fees earned from its transmission, gathering and processing operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced natural gas liquids (NGLs), if any, off of delivery points on its systems. Under other agreements, the Partnership transports natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the Partnership s FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with the Partnership s gathering and processing operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. The Partnership s revenue is a function of the volume of natural gas that it gathers and processes and is not directly dependent on the value of the natural gas.

Table of Contents

POP Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this situation, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership owns a percentage of that commodity and is directly subject to its market value.

Keep-Whole Contracts. These contracts require the Partnership, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, the Partnership bears the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that it paid for the unprocessed natural gas. However, because the natural gas purchases contracted under keep-whole agreements are generally low in liquids content and meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with a portion of the Partnership s keep-whole contracts is minimized.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership s records and management estimates of the related transportation and compression fees which are, in turn, based upon applicable product prices (see Use of Estimates accounting policy for further description). The Partnership had unbilled revenues at December 31, 2008 and 2007 of $54.8 million and $86.8 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its 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. These changes, other than net income (loss), are referred to as other comprehensive income (loss) and for the Partnership only include changes in the fair value of unsettled derivative contracts which are accounted for as cash flow hedges (see Note 9).

Recently Adopted Accounting Standards

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS No. 162). SFAS No. 162 identifies sources of accounting principles and the framework for selecting such principles used in the preparation of financial statements of nongovernmental entities presented in conformity with U.S. generally accepted accounting principles. SFAS No. 162 is effective beginning November 15, 2008. The Partnership adopted the provisions of SFAS No. 162 on November 15, 2008 and it had no impact on the Partnership s financial position and results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment to FASB Statement No. 115 (SFAS No. 159). SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 is effective at the inception of an entity s first fiscal year beginning after November 15, 2007 and offers various options in electing to apply its provisions. The Partnership adopted SFAS No. 159 on January 1, 2008, and has elected not to apply the fair value option to any of its financial instruments.

In December 2006, the FASB issued FASB Staff Position EITF 00-19-2, Accounting for Registration Payment Arrangements (EITF 00-19-2). EITF 00-19-2 provides guidance related to the accounting for registration payment arrangements and specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate arrangement or included as a provision of a financial instrument or arrangement, should be separately recognized and measured in accordance with SFAS No. 5, Accounting for Contingencies (SFAS No. 5). EITF 00-19-2 requires that if the transfer of consideration under a registration payment arrangement is probable and can be reasonably estimated at inception, the contingent liability under such arrangement shall be included in the allocation of proceeds from the related financing transaction using the measurement guidance in SFAS No. 5. The Partnership adopted EITF 00-19-2 on January 1, 2007 and it did not have an effect on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value statements. In February 2008, the FASB issued FASB Staff Position SFAS No. 157-b, Effective Date of FASB Statement No. 157 , which provides for a one-year deferral of the effective date of SFAS No. 157 with regard to an entity s non-financial assets, non-financial liabilities or any non-recurring fair value measurement. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Partnership adopted SFAS No. 157 on January 1, 2008 with respect to its derivative instruments, which are measured at fair value within its financial statements. The provisions of SFAS No. 157 have not been applied to its non-financial assets and non-financial liabilities. See Note 10 for disclosures pertaining to the provisions of SFAS No. 157 with regard to the Partnership s financial instruments.

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, Topic 1N, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108, Topic 1N). SAB 108, Topic 1N provides guidance on quantifying and evaluating the materiality of unrecorded misstatements. The SEC staff recommends that misstatements should be quantified using both a balance sheet and income statement approach and a determination be made as to whether either approach results in quantifying a misstatement which the registrant, after evaluating all relevant factors, considers material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct misstatements occurring in prior years that previously had been considered immaterial based on the appropriate use of the registrant s methodology. SAB 108, Topic 1N is effective for fiscal years ending on or after November 15, 2006. The Partnership adopted the provisions of SAB 108, Topic 1N on January 1, 2007 and it did not have an impact on the Partnership s consolidated financial position or results of operations for the years ended December 31, 2007 and 2006.

Recently Issued Accounting Standards

In June 2008, the FASB issued Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 applies to the calculation of earnings per share (EPS) described in paragraphs 60 and 61 of FASB Statement No. 128, Earnings per Share for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS pursuant to the two-class method. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. All prior-period EPS data presented shall be adjusted retrospectively to conform to the provisions of this FSP. The Partnership will apply the requirements of FSP EITF 03-6-1 upon its adoption on January 1, 2009 and it currently does not expect the adoption of FSP EITF 03-6-1 to have a material impact on its financial position and results of operations.

Table of Contents

In April 2008, the FASB issued Staff Position No. 142-3, Determination of Useful Life of Intangible Assets (FSP FAS 142-3). FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, Goodwill and Other Intangible Assets (SFAS 142). The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No 141(R), Business Combinations (SFAS No. 141(R)), and other U.S. Generally Accepted Accounting Principles. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. The guidance for determining the useful life of a recognized intangible asset should be applied prospectively to intangible assets acquired after the effective date. The disclosure requirements should be applied prospectively to all intangible assets recognized as of, and subsequent to, the effective date. The Partnership will apply the requirements of FSP FAS 142-3 upon its adoption on January 1, 2009 and it currently does not expect the adoption of FSP FAS 142-3 to have a material impact on its financial position and results of operations.

In March 2008, the FASB ratified the EITF consensus on EITF Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF No. 07-4), an update of EITF No. 03-6, Participating Securities and the Two-Class Method Under FASB Statement No. 128 (EITF No. 03-6). EITF 07-4 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. EITF 07-4 also 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. EITF No. 07-4 is effective for fiscal years beginning after December 15, 2008, including interim periods within those fiscal years, and requires retrospective application of the guidance to all periods presented. Early adoption is prohibited. The Partnership expects the adoption of EITF No. 07-4 will impact its presentation of net income (loss) per common limited partner unit as the Partnership currently presents net income (loss) per common limited partner unit as though all earnings were distributed each quarterly period (see Net Income (Loss) Per Common Unit). Under the guidance of EITF 07-4, management of the Partnership believes that the partnership agreement contractually limits cash distributions to available cash and, therefore, undistributed earnings will no longer be allocated to the incentive distribution rights upon adoption of EITF No. 07-4 effective January 1, 2009. EITF No. 07-4 would have had no impact on the Partnership s financial position or results of operations for the years ended December 31, 2007 and 2006.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 161 amends the requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to require enhanced disclosure about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008, with early adoption encouraged. The Partnership will apply the requirements of SFAS No. 161 upon its adoption on January 1, 2009 and does not expect it to have a material impact on its financial position or results of operations or related disclosures.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 amends ARB No. 51 to establish accounting and reporting standards for the noncontrolling interest (minority interest) in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 also requires consolidated net income to be reported, and disclosed on the face of the consolidated statement of operations, at amounts that include the amounts attributable to both the parent and the noncontrolling interest. Additionally, SFAS No. 160 establishes a single method for accounting for changes in a parent s ownership interest in a subsidiary that does not result in deconsolidation and that the parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS No. 160 is effective for fiscal years beginning on or after December 15, 2008. The Partnership will apply the requirements of SFAS No. 160 upon its adoption on January 1, 2009 and does not expect it to have a material impact on its financial position and results of operations.

In December 2007, the FASB issued SFAS No 141(R), Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) replaces SFAS No. 141, Business Combinations (SFAS No. 141), however retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) requires an acquirer to recognize the assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date, at their fair values as of that date, with specified limited exceptions. Changes subsequent to that date are to be recognized in earnings, not goodwill. Additionally, SFAS No. 141 (R) requires costs incurred in connection with an acquisition be expensed as incurred. Restructuring costs, if any, are to be recognized separately from the acquisition. The acquirer in a business combination achieved in stages must also recognize the identifiable assets and liabilities, as well as the noncontrolling interests in the acquiree, at the full amounts of their fair values. SFAS No. 141(R) is effective for business combinations occurring in fiscal years beginning on or after December 15, 2008. The Partnership will apply the requirements of SFAS No. 141(R) upon its adoption on January 1, 2009 and does not expect it to have a material impact on its financial position and results of operations.

NOTE 3 COMMON UNIT EQUITY OFFERINGS

In June 2008, the Partnership sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, the Partnership sold 1,112,000 common units to Atlas America and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. The Partnership also received a capital contribution from AHD of $5.4 million for AHD to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements (see Note 9).

In July 2007, the Partnership sold 25,568,175 common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125 billion. Of the 25,568,175 common units sold by the Partnership, 3,835,227 common units were purchased by AHD for $168.8 million. The Partnership also received a capital contribution from AHD of $23.1 million for AHD to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from the sale to partially fund the acquisition of control of the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and a 72.8% ownership interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (see Note 8). The common units issued were subsequently registered with the Securities and Exchange Commission in November 2007.

In May 2006, the Partnership sold 500,000 common units in a public offering at a price of $41.20 per unit, yielding net proceeds of approximately $19.7 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale to partially repay borrowings under its credit facility made in connection with its acquisition of the remaining 25% ownership interest in NOARK.

NOTE 4 PREFERRED UNIT EQUITY OFFERINGS

Class A Preferred Units

In March 2006, the Partnership entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units (Class A Preferred Units) representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for aggregate gross proceeds of $30.0 million. The Partnership also sold an additional 10,000 Class A Preferred Units to Sunlight Capital for $10.0 million in May 2006, pursuant to the Partnership s right under the agreement to require Sunlight Capital to purchase such additional units. The Class A Preferred Units were originally entitled to receive dividends of 6.5% per annum commencing in March 2007 and were to have been accrued and paid quarterly on the same date as the distribution payment date for the Partnership s common units. In April 2007, the Partnership and Sunlight Capital agreed to amend the terms of the Class A Preferred Units effective as of that date. The terms of the Class A Preferred Units were amended to entitle them to receive dividends of 6.5% per annum commencing in March 2008 and to be convertible, at Sunlight Capital s option, into common units commencing May 8, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of the Partnership s common units as of the date of the notice of conversion. The Partnership may elect to pay cash rather than issue common units in satisfaction of a conversion request.

The Partnership has the right to call the Class A Preferred Units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.22. If not converted into common units or redeemed prior to the second anniversary of the conversion commencement date, the Class A Preferred Units will automatically be converted into the Partnership s common units in accordance with the agreement. In consideration of Sunlight Capital s consent to the amendment of the Class A Preferred Units, the Partnership issued $8.5 million of its 8.125% senior unsecured notes due 2015 to Sunlight Capital. The Partnership recorded the senior unsecured notes issued as long-term debt and a preferred unit dividend within partners capital on its consolidated balance sheet and, during the year ended December 31, 2007, reduced net income (loss) attributable to common limited partners and the general partner by $3.8 million of this amount, which was the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the Class A preferred unitholder, on its consolidated statements of operations.

In December 2008, the Partnership redeemed 10,000 of the Class A Preferred Units for $10.0 million in cash under the terms of the agreement (see Note 19). The redemption was classified as a reduction of Class A Preferred Equity within partners capital on the Partnership s consolidated balance sheet. The Partnership s 30,000 outstanding Class A preferred limited partner units were convertible into approximately 5,263,158 common limited partner units at December 31, 2008, which is based upon the market value of the Partnership s common units and subject to provisions and limitations within the agreement between the parties, with an estimated fair value of approximately $31.6 million based upon the market value of the Partnership s common units as of that date.

Dividends previously paid and those to be paid on the Class A Preferred Units and the premium paid upon their redemption, if any, will be recognized as a reduction to the Partnership s net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. If converted to common units, the Class A preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership s consolidated balance sheet.

The Class A Preferred Units are reflected on the Partnership s consolidated balance sheet as Class A preferred equity within partners capital of $27.9 million and $37.1 million at December 31, 2008 and 2007, respectively. In accordance with Securities and Exchange Commission Staff Accounting Bulletin No. 68, Increasing Rate Preferred Stock, the Class A Preferred Units were originally recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. The imputed dividend cost of $2.4 million was the result of the Class A Preferred Units not having a dividend yield during the first year after their issuance in March 2006 and was amortized in full as of March 2007. As a result of the amended agreement, the Partnership recognized an imputed dividend cost of $2.5 million that was amortized during the year commencing March 2007 and was based upon the present value of the net proceeds received using the 6.5% stated yield. During the year ending December 31, 2008, the Partnership amortized the remaining $0.5 million of this imputed dividend cost, which is presented as an additional adjustment of net income (loss) to determine net income (loss) attributable to common limited partners and the general partner on its consolidated statements of operations. Amortization of the imputed dividend cost was $2.5 million for the year ended December 31, 2007, based on the imputed cost during the year commencing March 2007. Amortization of the imputed dividend cost was $1.9 million for the year ended December 31, 2006, based on the $2.4 million imputed cost during the initial year after the unit issuance. If converted to common units, the Class A preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership s consolidated balance sheet. Dividends accrued and paid on the Class A Preferred Units and the premium paid upon their redemption, if any, will be recognized as a reduction to the Partnership s net income (loss) in determining net income (loss) attributable to common unitholders and the general partner.

Sunlight Capital was entitled to receive the dividends on the Class A Preferred Units pro rata from the March 2008 commencement date. The Partnership recognized $1.8 million of preferred dividend cost for the year ended December 31, 2008, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the general partner on its consolidated statements of operations. The preferred dividend cost recognized by the Partnership for the respective periods is associated with the preferred dividends earned during those periods and paid on the scheduled date of the Partnership s quarterly cash distribution for the respective period (see Note 5). The $0.5 million of preferred unit dividend cost recognized for the three months ended December 31, 2008 is based upon the preferred unit dividend to be paid on February 13, 2009.

The net proceeds from the initial issuance of the preferred units were used to fund a portion of the Partnership s capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under the Partnership s credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK.

Class B Preferred Units

In December 2008, the Partnership sold 10,000 12.0% cumulative convertible Class B preferred units of limited partner interests (the Class B Preferred Units) to AHD for cash consideration of $1,000 per Class B Preferred Unit (the Face Value) pursuant to a purchase agreement (the Class B Preferred Unit Purchase Agreement). AHD has the right, before March 30, 2009, to purchase an additional 10,000 Class B Preferred Units on the same terms. The Partnership used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units will receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for the Partnership s common units. The record date for the determination of holders entitled to receive distributions of the Class B Preferred Units will be the same as the record date for determination of common unit holders entitled to receive quarterly distributions. The Class B Preferred Units are convertible, at the holder s option, into common units commencing on June 30, 2009 (the Class B Preferred Unit Conversion Commencement Date), provided that the holder must request conversion of at least 2,500 Class B Preferred Units and cannot make a conversion request more than once every 30 days. The conversion price will be the lesser of (a) $7.50 (subject to adjustment for customary events such as stock splits, reverse stock splits, stock distributions and spin-offs) and (b) 95% of the average closing price of the common units for the 10 consecutive trading days immediately preceding the date of the holder s notice to the Partnership of its conversion election (the Market Price). The number of common units issuable is equal to the Face Value of the Class B Preferred Units being converted plus all accrued but unpaid distributions (the Class B Preferred Unit Liquidation Value), divided by the conversion price. Within 5 trading days of its receipt of a conversion notice, the Partnership may elect to pay the notifying holder cash rather than issue common units in satisfaction of the conversion request. If the Partnership elects to pay cash for the Class B Preferred Units, the conversion price will be the lesser of (a) $7.50 and (b) 100% of the Market Price and the cash amount will be equal to (x) if Market Price is greater than $7.50, the number of common units issuable for the Class B Preferred Units being redeemed multiplied by the Market Price or (y) if the Market Price is less than or equal to $7.50, the Class B Preferred Unit Liquidation Value. The Partnership has the right to redeem some or all of the Class B Preferred Units (but not less than 2,500 Class B Preferred Units) for an amount equal to the Class B Preferred Unit Liquidation Value being redeemed divided by the conversion price multiplied by $9.50.

Table of Contents

The sale of the Class B Preferred Units to AHD is exempt from the registration requirements of the Securities Act of 1933. The Partnership has agreed pursuant to a registration rights agreement entered into simultaneously with the Class B Preferred Unit Purchase Agreement to file, upon demand, a registration statement to cover the resale of the common units underlying the Class B Preferred Units. AHD is entitled to receive the dividends on the Class B Preferred Units pro rata from the December 2008 commencement date. Dividends to be paid on the Class B Preferred Units and the premium paid upon their redemption, if any, will be recognized as a reduction to the Partnership s net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. If converted to common units, the Class B preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership s consolidated balance sheet.

The Partnership s 10,000 outstanding Class B preferred limited partner units were convertible into approximately 1,754,386 common limited partner units at December 31, 2008, which is based upon the market value of the Partnership s common units and subject to provisions and limitations within the agreement between the parties, with an estimated fair value of approximately $10.5 million based upon the market value of the Partnership s common units as of that date.

Dividends to be paid on the Class B Preferred Units and the premium paid upon their redemption, if any, will be recognized as a reduction to the Partnership s net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. If converted to common units, the Class B preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership s consolidated balance sheet. The Class B Preferred Units are reflected on the Partnership s consolidated balance sheet as Class B preferred equity within partners capital of $10.0 million at December 31, 2008.

NOTE 5 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of its available cash (as defined in its partnership agreement) for that quarter to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and General Partner distributions declared by the Partnership for the period from January 1, 2006 through December 31, 2008 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 14, 2006	December 31, 2005	$ 0.83	$ 10,416	$ 3,638
May 15, 2006	March 31, 2006	$ 0.84	$ 10,541	$ 3,766
August 14, 2006	June 30, 2006	$ 0.85	$ 11,118	$ 4,059
November 14, 2006	September 30, 2006	$ 0.85	$ 11,118	$ 4,059
February 14, 2007	December 31, 2006	$ 0.86	$ 11,249	$ 4,193
May 15, 2007	March 31, 2007	$ 0.86	$ 11,249	$ 4,193
August 14, 2007	June 30, 2007	$ 0.87	$ 11,380	$ 4,326
November 14, 2007	September 30, 2007	$ 0.91	$ 35,205	$ 4,498
February 14, 2008	December 31, 2007	$ 0.93	$ 36,051	$ 5,092
May 15, 2008	March 31, 2008	$ 0.94	$ 36,450	$ 7,891
August 14, 2008	June 30, 2008	$ 0.96	$ 44,096	$ 9,308
November 14, 2008	September 30, 2008	$ 0.96	$ 44,105	$ 9,312

Table of Contents

In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems (see Note 8), AHD, which holds all of the incentive distribution rights in the Partnership, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. AHD also agreed that the resulting allocation of incentive distribution rights back to the Partnership would be after AHD receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter.

On January 26, 2009, the Partnership declared a cash distribution of $0.38 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended December 31, 2008. The $17.8 million distribution, including $0.4 million to the General Partner, was paid on February 13, 2009 to unitholders of record at the close of business on February 9, 2009.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	December 31,		Estimated Useful Lives
	2008	**2007**	**in Years**
Pipelines, processing and compression facilities	$ 1,959,379	$ 1,633,454	15 40
Rights of way	178,114	168,359	20 40
Buildings	8,968	8,919	40
Furniture and equipment	9,387	7,235	3 7
Other	13,812	13,307	3 10
	2,169,660	1,831,274	
Less accumulated depreciation	(146,723)	(82,613)	
	$ 2,022,937	$ 1,748,661	

During the year ended December 31, 2008, the Partnership recognized impairment charges totaling $21.6 million within goodwill and other asset impairment loss on its consolidated statements of operations in connection with a write-off of costs related to a pipeline expansion project. The costs incurred consisted of preliminary construction and engineering costs incurred as well as a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

In July 2007, the Partnership acquired control of the Chaney Dell and Midkiff/Benedum systems (see Note 8). During the fourth quarter of 2007 and first quarter of 2008, the Partnership adjusted its preliminary purchase price allocation by adjusting the estimated amounts allocated to goodwill and property, plant, and equipment.

NOTE 7 OTHER ASSETS

The following is a summary of other assets (in thousands):

	December 31,	
	2008	**2007**
Deferred finance costs, net of accumulated amortization of $17,298 and $11,352 at December 31, 2008 and 2007, respectively	$ 23,676	$ 18,227
Security deposits	1,419	2,498
Other	137	156
	$ 25,232	$ 20,881

89

Table of Contents

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 11). In December 2008, the Partnership recorded $1.3 million for accelerated amortization of deferred financing costs associated with the repurchase of approximately $60.0 million in face amount of its Senior Notes. In June 2008, the Partnership recorded $1.2 million for accelerated amortization of deferred financing costs associated with the retirement of a portion of its term loan with a portion of the net proceeds from its issuance of Senior Notes. In July 2007, the Partnership recorded $5.0 million for accelerated amortization of deferred financing costs associated with the replacement of its previous credit facility with a new facility.

NOTE 8 ACQUISITIONS

Chaney Dell and Midkiff/Benedum

In July 2007, the Partnership acquired control of Anadarko s 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). The transaction was effected by the formation of two joint venture companies which own the respective systems, to which the Partnership contributed $1.9 billion and Anadarko contributed the Anadarko Assets.

The Partnership funded the purchase price in part from the private placement of 25,568,175 common limited partner units at a negotiated purchase price of $44.00 per unit, generating gross proceeds of $1.125 billion. Of the $1.125 billion, $168.8 million of these units were purchased by AHD. The Partnership funded the remaining purchase price from $830.0 million of proceeds from a senior secured term loan which matures in July 2014 and borrowings from its senior secured revolving credit facility that matures in July 2013 (see Note 11). AHD, which holds all of the incentive distribution rights in the Partnership, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. AHD also agreed that the resulting allocation of incentive distribution rights back to the Partnership would be after AHD receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter (see Note 5).

In connection with this acquisition, the Partnership reached an agreement with Pioneer, which currently holds a 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer has an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system, which began on June 15, 2008 and ended on November 1, 2008, and up to an additional 7.4% interest beginning on June 15, 2009 and ending on November 1, 2009 (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009). If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22.0% interest if fully exercised. The Partnership will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options.

The acquisition was accounted for using the purchase method of accounting under SFAS No. 141. The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in the acquisition, based on their fair values at the date of the acquisition (in thousands):

Accounts receivable	$ 745
Prepaid expenses and other	4,587
Property, plant and equipment	1,030,464
Intangible assets customer relationships	205,312
Goodwill	613,420
Total assets acquired	1,854,528
Accounts payable and accrued liabilities	(1,499)
Net cash paid for acquisition	$ 1,853,029

Table of Contents

The Partnership initially recorded goodwill in connection with this acquisition as a result of Chaney Dell s and Midkiff/Benedum s significant cash flow and strategic industry position. The Partnership tested its goodwill for impairment at December 31, 2008 and recognized an impairment charge of $676.9 million during the year ended December 31, 2008, which included the amounts recognized in connection with its Chaney Dell and Midkiff/Benedum acquisitions (see Goodwill in Note 2).

In April 2008, the Partnership received a $30.2 million cash reimbursement for state sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement of the sales tax paid in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition. The results of Chaney Dell s and Midkiff/Benedum s operations are included within the Partnership s consolidated financial statements from the date of acquisition.

NOARK

In May 2006, the Partnership acquired the remaining 25% ownership interest in NOARK from Southwestern, for a net purchase price of $65.5 million, consisting of $69.0 million of cash to the seller (including the repayment of the $39.0 million of outstanding NOARK notes at the date of acquisition), less the seller s interest in NOARK s working capital (including cash on hand and net payables to the seller) at the date of acquisition of $3.5 million. In October 2005, the Partnership acquired from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE), all of the outstanding equity of Atlas Arkansas Pipeline, LLC, which owned the initial 75% ownership interest in NOARK, for total consideration of $179.8 million, including $16.8 million for working capital adjustments and other related transaction costs. NOARK s assets included a Federal Energy Regulatory Commission (FERC)-regulated interstate pipeline and an unregulated natural gas gathering system. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141. The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in both acquisitions, based on their fair values at the date of the respective acquisitions (in thousands):

Cash and cash equivalents	$ 16,215
Accounts receivable	11,091
Prepaid expenses	497
Property, plant and equipment	232,576
Other assets	140
Total assets acquired	260,519
Accounts payable and other liabilities	(50,689)
Net assets acquired	209,830
Less: Cash and cash equivalents acquired	(16,215)
Net cash paid for acquisitions	$ 193,615

The Partnership s ownership interests in the results of NOARK s operations associated with each acquisition are included within its consolidated financial statements from the respective dates of the acquisitions.

Table of Contents

The following data presents pro forma revenue and net income (loss) for the Partnership for the years ended December 31, 2007 and 2006 as if the acquisitions discussed above, the equity offerings in July 2007 and May 2006 (see Note 3), the proceeds of $830.0 million from a senior unsecured term loan and borrowings under a the Partnership s senior secured revolving credit facility (see Note 11), the April 2007 and May 2006 issuances of senior notes (see Note 11), and the May 2006 and March 2006 issuances of the cumulative convertible preferred units (see Note 4) had occurred on January 1, 2006. The data also presents actual revenue, net income (loss) and net income (loss) per common limited partner unit for the Partnership for the year ended December 31, 2008 for comparative purposes. The Partnership has prepared these unaudited pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if the Partnership had completed these acquisitions and financing transactions at the beginning of the periods shown below or the results that will be attained in the future (in thousands, except per unit data; unaudited):

	Years Ended December 31,		
	2008	2007	2006
Total revenue and other income (loss), net	$ 1,414,190	$ 990,032	$ 1,090,583
Net income (loss)	(581,917)	(135,772)	32,498
Net income (loss) attributable to common limited partners and the general partner	(584,191)	(142,026)	26,244
Net income (loss) attributable to common limited partners per unit:			
Basic	$ (15.62)	$ (4.00)	$ 0.29
Diluted	$ (15.62)	$ (4.00)	$ 0.29

NOTE 9 DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps and options, in connection with its commodity price and interest rate risk management activities. The Partnership enters into financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. It also enters into financial swap instruments to hedge certain portions of its floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. Under 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. Commodity-based option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period.

The Partnership applies the provisions of SFAS No. 133 to its derivative instruments. The Partnership formally documents all relationships between hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching derivative contracts to the forecasted transactions. Under SFAS No. 133, the Partnership can assess, 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 is determined by the Partnership through the utilization of market data, will be recognized within other income (loss), net in its consolidated statements of operations. For derivatives previously qualifying as hedges, the Partnership recognized the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassified the portion relating to commodity derivatives to natural gas and liquids revenue and the portion relating to interest rate derivatives to interest expense within its consolidated statements of operations as the underlying transactions were settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, the Partnership recognizes changes in fair value within other income (loss), net in its consolidated statements of operations as they occur.

On July 1, 2008, the Partnership elected to discontinue hedge accounting for its existing commodity derivatives which were qualified as hedges under SFAS No. 133. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. The fair value of these commodity derivative instruments at June 30, 2008, which was recognized in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings.

During the year ended December 31, 2008, the Partnership made net payments of $274.0 million related to the early termination of derivative contracts that were principally entered into as proxy hedges for the prices received on the ethane and propane portion of its NGL equity volume. Substantially all of these derivative contracts were put into place simultaneously with the Partnership s acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. During the years ended December 31, 2008, 2007 and 2006, the Partnership recognized the following derivative activity related to the termination of these derivative instruments within its consolidated statement of operations (amounts in thousands):

	Early termination of derivative contracts for the Years Ended December 31,		
	2008	2007	2006
Net cash derivative expense included within other income (loss), net	$ (199,964)	$	$
Net cash derivative income included within natural gas and liquids revenue	2,322		
Net non-cash derivative expense included within other income (loss), net	(39,218)		
Net non-cash derivative expense included within natural gas and liquids	(32,389)		

In addition, $37.3 million will be reclassified from accumulated other comprehensive loss within partner s capital on the Partnership s consolidated balance sheet and recognized as non-cash derivative expenses during the period beginning on January 1, 2009 and ending on December 31, 2009, the remaining period for which the derivatives were originally scheduled to be settled, as a result of the early termination of certain derivatives that were classified as cash flow hedges in accordance with SFAS No. 133 at the date of termination.

At December 31, 2008, the Partnership had interest rate derivative contracts having aggregate notional principal amounts of $450.0 million, which were designated as cash flow hedges. Under the terms of these agreements, the Partnership will pay weighted average interest rates of 3.02%, plus the applicable margin as defined under the terms of its revolving credit facility (see Note 11), and will receive LIBOR, plus the applicable margin, on the notional principal amounts. These derivatives effectively convert $450.0 million of the Partnership s floating rate debt under the term loan and revolving credit facility to fixed-rate debt. The interest rate swap agreements were effective as of December 31, 2008 and expire during periods ranging from January 30, 2010 through April 30, 2010.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. At December 31, 2008 and 2007, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $63.6 million and $229.5 million, respectively. Of the $104.9 million of net loss in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet at December 31, 2008, if the fair values of the instruments remain at current market values, the Partnership will reclassify $56.2 million of losses to the Partnership s consolidated statements of operations over the next twelve month period, consisting of $46.2 million of losses to natural gas and liquids revenue and $10.0 million of losses to interest expense. Aggregate losses of $48.7 million will be reclassified to the Partnership s consolidated statements of operations in later periods, consisting of $46.9 million of losses to natural gas and liquids revenue and $1.8 million of losses to interest expense. Actual amounts that will be reclassified will vary as a result of future price change.

On June 3, 2007, the Partnership signed definitive agreements to acquire control of the Chaney Dell and Midkiff/Benedum systems (see Note 8). In connection with certain additional agreements entered into to finance this transaction, the Partnership agreed as a condition precedent to closing that it would hedge 80% of its projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, the Partnership entered into derivative instruments to hedge 80% of the projected production of the Anadarko Assets to be acquired as required under the financing agreements. The production volume of the Anadarko Assets to be acquired was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the Anadarko Assets had not yet been completed. Accordingly, the Partnership recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in its consolidated statements of operations. The Partnership recognized a non-cash loss of $18.8 million related to the change in value of derivatives entered into specifically for the Chaney Dell and Midkiff/Benedum systems from the time the derivative instruments were entered into to the date of closing of the acquisition during the year ended December 31, 2007. Upon closing of the acquisition in July 2007, the production volume of the Anadarko Assets acquired was considered probable forecasted production under SFAS No. 133. The Partnership designated many of these instruments as cash flow hedges and evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

During December 2007, the Partnership discontinued hedge accounting for crude oil derivative instruments covering certain forecasted condensate production for 2008 and other future periods, and then documented these derivative instruments to match certain forecasted NGL production for the respective periods. The discontinuation of hedge accounting for these instruments with regard to the Partnership s condensate production resulted in a $12.6 million non-cash derivative loss recognized within other income (loss), net in its consolidated statements of operations and a corresponding decrease in accumulated other comprehensive loss in partners capital in its consolidated balance sheet.

The fair value of the Partnership s derivative instruments was included in its consolidated balance sheets as follows (in thousands):

	December 31,	
	2008	2007
Current portion of derivative asset	$ 44,961	$
Long-term hedge asset		
Current portion of derivative liability	(60,396)	(110,867)
Long-term derivative liability	(48,159)	(118,646)
	$ (63,594)	$ (229,513)

Table of Contents

The following table summarizes the Partnership s derivative activity for the periods indicated (amounts in thousands):

	Years Ended December 31, 2008	2007	2006
Loss from cash and non-cash settlement of qualifying hedge instruments(1)	$ (105,015)	$ (49,393)	$ (13,945)
Gain (loss) from change in market value of non-qualifying derivatives(2)	140,144	(153,363)	4,206
Loss from de-designation of cash flow derivatives(2)		(12,611)	
Gain (loss) from change in market value of ineffective portion of qualifying derivatives(2)	47,229	(3,450)	1,520
Loss from cash and non-cash settlement of non-qualifying derivatives(2)	(250,853)	(10,158)	
Loss from cash settlement of interest rate derivatives(3)	(1,226)		

(1) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.
(2) Included within other income (loss), net on the Partnership s consolidated statements of operations.
(3) Included within interest expense on the Partnership s consolidated statements of operations.

As of December 31, 2008, the Partnership had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Term	Notional Amount	Type		Contract Period Ended December 31,	Fair Value Liability(1) (in thousands)
January 2008-January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	2009	$ (4,130)
				2010	(249)
					$ (4,379)
April 2008-April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2009	$ (5,835)
				2010	(1,513)
					$ (7,348)

Natural Gas Liquids Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Asset(2) (in thousands)
2009	8,568,000	$ 0.746	$ 1,509

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)(3) (in thousands)	Option Type
2009	1,056,000	56,634,732	$ 80.00	$ 29,006	Puts purchased
2009	304,200	27,085,968	$ 126.05	(22,774)	Puts sold(4)

2009	304,200	27,085,968	$	143.00	44	Calls purchased(4)
2009	2,121,600	114,072,336	$	81.01	(1,080)	Calls sold
2010	3,127,500	202,370,490	$	81.09	(17,740)	Calls sold
2010	714,000	45,415,440	$	120.00	1,279	Calls purchased(4)
2011	606,000	32,578,560	$	95.56	(3,123)	Calls sold
2011	252,000	13,547,520	$	120.00	646	Calls purchased(4)
2012	450,000	24,192,000	$	97.10	(2,733)	Calls sold
2012	180,000	9,676,800	$	120.00	607	Calls purchased(4)
					$ (15,868)	

95

Table of Contents

Natural Gas Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu) (5)	Fair Value Asset (3) (in thousands)
2009	5,247,000	$ 8.611	$ 14,326
2010	4,560,000	$ 8.526	6,461
2011	2,160,000	$ 8.270	2,072
2012	1,560,000	$ 8.250	1,596
			$ 24,455

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Asset/(Liability)(3) (in thousands)
2009	5,724,000	$ (0.558)	$ (1,220)
2010	4,560,000	$ (0.622)	1,106
2011	2,160,000	$ (0.664)	367
2012	1,560,000	$ (0.601)	316
			$ 569

Natural Gas Purchases Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Liability(3) (in thousands)
2009	14,267,000	$ 8.680	$ (36,734)
2010	8,940,000	$ 8.580	(13,403)
2011	2,160,000	$ 8.270	(2,072)
2012	1,560,000	$ 8.250	(1,596)
			$ (53,805)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Liability(3) (in thousands)
2009	15,564,000	$ (0.654)	$ (9,201)
2010	8,940,000	$ (0.600)	(3,720)
2011	2,160,000	$ (0.700)	(423)
2012	1,560,000	$ (0.610)	(383)
			$ (13,727)

Ethane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Asset[2] (in thousands)	Option Type
2009	14,049,000	$ 0.6948	$ 3,234	Puts purchased

Table of Contents

Propane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Asset(2) (in thousands)	Option Type
2009	14,490,000	$ 1.4154	$ 9,083	Puts purchased

Isobutane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(2) (in thousands)	Option Type
2009	126,000	$ 0.7500	$ (3)	Puts purchased

Normal Butane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(2) (in thousands)	Option Type
2009	113,400	$ 0.7350	$ (3)	Puts purchased

Natural Gasoline Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Asset(2) (in thousands)	Option Type
2009	126,000	$ 0.9650	$ 5	Puts purchased

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Asset(3) (in thousands)
2009	33,000	$ 62.700	$ 252

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability)(3) (in thousands)	Option Type
2009	105,000	$ 90.000	$ 3,635	Puts purchased
2009	306,000	$ 80.017	(6,122)	Calls sold
2010	234,000	$ 83.027	(4,046)	Calls sold

2011	72,000	$ 87.296		(546)	Calls sold
2012	48,000	$ 83.944		(489)	Calls sold
			$	(7,568)	
Total net liability			$	(63,594)	

(1) Fair value based on independent, third-party statements, supported by observable levels at which transactions are executed in the marketplace.

(2) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas, light crude and propane prices.

(3) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

(4) Puts sold and calls purchased for 2009 represent costless collars entered into by the Partnership as offsetting positions for the calls sold related to ethane and propane production. In addition, calls were purchased for 2010 through 2012 to offset positions for calls sold. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

(5) Mmbtu represents million British Thermal Units.

Table of Contents

NOTE 10 FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Instruments

The Partnership adopted the provisions of SFAS No. 157 at January 1, 2008. SFAS No. 157 establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. SFAS No. 157 s 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 assumption 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.

The Partnership uses the fair value methodology outlined in SFAS No. 157 to value the assets and liabilities for its respective outstanding derivative contracts (see Note 9). All of the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and crude oil options. The Partnership s Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. The Partnership s interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for the Partnership s NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of natural gas, crude oil, and propane prices, and therefore are defined as Level 3. Valuations for the Partnership s crude oil options (including those associated with NGL sales) are based on forward price curves developed by the related financial institution based upon current quoted prices for crude oil futures, and therefore are defined at Level 3. In accordance with SFAS No. 157, the following table represents the Partnership s assets and liabilities recorded at fair value as of December 31, 2008 (in thousands):

	Level 1	Level 2	Level 3	Total
Commodity-based derivatives	$	$ (42,256)	$ (9,611)	$ (51,867)
Interest rate swap-based derivatives		(11,727)		(11,727)
Total	$	$ (53,983)	$ (9,611)	$ (63,594)

Table of Contents

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and crude oil options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments as of December 31, 2008 (in thousands):

	NGL Fixed Price Swaps	Crude Oil Sales Options (associated with NGL Volume)	Crude Oil Sales Options	NGL Sales Options	Total
Balance December 31, 2007	$ (33,624)	$ (145,418)	$ (24,740)	$	$ (203,782)
New options contracts		20,451	6,012	24,529	50,992
Cash settlements from unrealized gain (loss)[1]	(7,396)	224,956	(3,926)	(12,154)	201,480
Cash settlements from other comprehensive income[1]	33,895	92,432	13,406		139,733
Net change in unrealized gain (loss)[2]	17,321	(57,934)	36,159		(4,454)
Deferred option premium recognition		150	468	(59)	559
Net change in other comprehensive loss	(8,687)	(150,504)	(34,948)		(194,139)
Balance December 31, 2008	$ 1,509	$ (15,867)	$ (7,569)	$ 12,316	$ (9,611)

(1) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.
(2) Included within other income (loss), net on the Partnership s consolidated statements of operations.

Other Financial Instruments

The estimated fair value of the Partnership s other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts that the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership s other current assets and liabilities on its consolidated balance sheets are financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature. The estimated fair values of the Partnership s long-term debt at December 31, 2008 and 2007, which consists principally of the term loan, the Senior Notes and borrowings under the credit facility, was $1,153.2 million and $1,225.6 million, respectively, compared with the carrying amount of $1,493.4 million and $1,229.4 million, respectively. The term loan and Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

NOTE 11 DEBT

Total debt consists of the following (in thousands):

	December 31, 2008	December 31, 2007
Revolving credit facility	$ 302,000	$ 105,000
Term loan	707,180	830,000
8.125% Senior notes due 2015	261,197	294,392
8.75% Senior notes due 2018	223,050	
Other debt		34
Total debt	1,493,427	1,229,426
Less current maturities		(34)
Total long-term debt	$ 1,493,427	$ 1,229,392

Term Loan and Credit Facility

At December 31, 2008, the Partnership had a senior secured credit facility with a syndicate of banks which consisted of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at the Partnership s option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding revolving credit facility borrowings at December 31, 2008 was 3.7%, and the weighted average interest rate on the outstanding term loan borrowings at December 31, 2008 was 3.0%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $5.9 million was outstanding at December 31, 2008. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet.

In June 2008, the Partnership entered into an amendment to its revolving credit facility and term loan agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to the Partnership s early termination of certain derivative contracts (see Note 9) in calculating its Consolidated EBITDA. Pursuant to this amendment, in June 2008, the Partnership repaid $122.8 million of its outstanding term loan and repaid $120.0 million of outstanding borrowings under the credit facility with proceeds from its issuance of $250.0 million of 10-year, 8.75% senior unsecured notes (see Senior Notes). Additionally, pursuant to this amendment, in June 2008 the Partnership s lenders increased their commitments for the revolving credit facility by $80.0 million to $380.0 million.

Borrowings under the credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum joint ventures, and by the guaranty of each of its consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is in compliance with these covenants as of December 31, 2008. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt and equity issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with entering into the credit facility, the Partnership agreed to remit an underwriting fee to the lead underwriting bank of 0.75% of the aggregate principal amount of the term loan outstanding on January 23, 2008. Since then, the Partnership and the underwriting bank agreed to extend the agreement through January 30, 2009 and reduce the underwriting fee to 0.50% of the aggregate principal amount of the term loan outstanding as of that date.

The events which constitute an event of default for the Partnership s credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner. The credit facility requires the Partnership to maintain a ratio of funded debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.75 to 1.0. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of December 31, 2008, the Partnership s ratio of funded debt to EBITDA was 4.7 to 1.0 and its interest coverage ratio was 4.0 to 1.0.

The Partnership is unable to borrow under its credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement.

Senior Notes

At December 31, 2008, the Partnership had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $261.2 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with $0.7 million of unamortized premium received as of December 31, 2008. The 8.75% Senior Notes were issued in June 2008 in

Table of Contents

a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $244.9 million, after underwriting commissions and other transaction costs. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, the Partnership may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its credit facility.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; 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 its assets. The Partnership is in compliance with these covenants as of December 31, 2008.

In connection with the issuance of the 8.75% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If the Partnership did not meet the aforementioned deadline, the 8.75% Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that the Partnership had caused the exchange offer to be consummated. On November 21, 2008, the Partnership filed an exchange offer registration statement for the 8.75% Senior Notes with the Securities and Exchange Commission, which was declared effective on December 16, 2008. The exchange offer was consummated on January 21, 2009, thereby fulfilling all of the requirements of the 8.75% Senior Notes registration rights agreement by the specified dates.

In December 2008, the Partnership repurchased approximately $60.0 million in face amount of its Senior Notes for an aggregate purchase price of approximately $40.1 million plus accrued interest of approximately $2.0 million. The notes repurchased were comprised of $33.0 million in face amount of the Partnership s 8.125% Senior Notes and approximately $27.0 million in face amount of its 8.75% Senior Notes. All of the Senior Notes repurchased have been retired and are not available for re-issue.

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

Years Ended December 31:	
2009	$
2010	
2011	
2012	
2013	302,000
Thereafter	1,191,427
	$ 1,493,427

Cash payments for interest related to debt were $85.9 million, $57.2 million and $25.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Table of Contents

NOTE 12 COMMITMENTS AND CONTINGENCIES

The Partnership has noncancelable operating leases for equipment and office space. Total rental expense for the years ended December 31, 2008, 2007 and 2006 was $9.1 million, $5.6 million and $4.0 million, respectively. The aggregate amount of remaining future minimum annual lease payments as of December 31, 2008 is as follows (in thousands):

Years Ended December 31:	
2009	$ 4,953
2010	3,115
2011	2,221
2012	1,116
2013	130
Thereafter	
	$ 11,535

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on its financial condition or results of operations.

As of December 31, 2008, the Partnership is committed to expend approximately $93.0 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

NOTE 13 CONCENTRATIONS OF CREDIT RISK

The Partnership sells natural gas and NGLs under contract to various purchasers in the normal course of business. For the year ended December 31, 2008, the Mid-Continent segment had two customers that individually accounted for approximately 50% and 13% of the Partnership s consolidated total revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2007, the Mid-Continent segment had one customer that individually accounted for approximately 50% of the Partnership s consolidated total revenues, excluding the impact of all financial derivative activity. For the year ended December 31, 2006, the Mid-Continent segment had three customers that individually accounted for approximately 36%, 18% and 10% of the Partnership s consolidated total revenues, excluding the impact of all financial derivative activity. Additionally, the Mid-Continent segment had one customer that individually accounted for approximately 37% of the Partnership s consolidated accounts receivable at December 31, 2008, and two customers that individually accounted for approximately 26% and 11% of the Partnership s consolidated accounts receivable at December 31, 2007. Substantially all of the Appalachian segment s revenues are derived from a master gas gathering agreement with Atlas Energy.

The Partnership has certain producers which supply a majority of the natural gas to its Mid-Continent gathering and transportation systems and processing facilities. A reduction in the volume of natural gas that any one of these producers supply to the Partnership could adversely affect its operating results unless comparable volume could be obtained from other producers in the surrounding region.

The Partnership places its temporary cash investments in high quality short-term money market instruments and deposits with high quality financial institutions. At December 31, 2008, the Partnership and its subsidiaries had $5.8 million in deposits at banks, of which $4.6 million was over the insurance limit of the Federal Deposit Insurance Corporation. No losses have been experienced on such investments.

Table of Contents

NOTE 14 STOCK COMPENSATION

Long-Term Incentive Plan

The Partnership has a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner s affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by General Partner s managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units. Only phantom units have been granted under the LTIP through December 31, 2008.

A phantom unit entitles a grantee to receive a common unit, without payment of an exercise price, upon vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. In addition, the Committee may grant a participant a distribution equivalent right (DER), which is the right to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. A unit option entitles the grantee to purchase the Partnership s common limited partner units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through December 31, 2008, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined in the LTIP. Of the units outstanding under the LTIP at December 31, 2008, 55,228 units will vest within the following twelve months. All units outstanding under the LTIP at December 31, 2008 include DERs granted to the participants by the Committee. The amounts paid with respect to LTIP DERs were $0.5 million, $0.6 million and $0.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. These amounts were recorded as reductions of Partners Capital on the Partnership s consolidated balance sheet.

The Partnership follows the provisions of SFAS No. 123(R), Share-Based Payment , as revised (SFAS No. 123(R)). Generally, the approach to accounting in SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

The following table sets forth the LTIP phantom unit activity for the periods indicated:

	Years Ended December 31,		
	2008	**2007**	**2006**
Outstanding, beginning of year	129,746	159,067	110,128
Granted[(1)]	54,796	25,095	82,091
Matured[(2)]	(56,227)	(51,166)	(31,152)
Forfeited	(1,750)	(3,250)	(2,000)
Outstanding, end of year[(3)]	126,565	129,746	159,067
Non-cash compensation expense recognized (in thousands)	$ 2,313	$ 2,936	$ 2,030

(1) The weighted average price for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense and does not represent an exercise price to be paid by the recipient, was $44.28, $50.09 and $45.45 for awards granted for the years ended December 31, 2008, 2007 and 2006, respectively.

(2) The intrinsic values for phantom unit awards exercised during the years ended at December 31, 2008, 2007 and 2006 are $2.0 million, $2.6 million and $1.3 million, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at December 31, 2008 is $0.8 million.

At December 31, 2008, the Partnership had approximately $2.1 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIP based upon the fair value of the awards.

Incentive Compensation Agreements

The Partnership has incentive compensation agreements which have granted awards to certain key employees retained from previously consummated acquisitions. These individuals were entitled to receive common units of the Partnership upon the vesting of the awards, which was dependent upon the achievement of certain predetermined performance targets through September 30, 2007. At September 30, 2007, the predetermined performance targets were achieved and all of the awards under the incentive compensation agreements vested. Of the total common units to be issued under the incentive compensation agreements, 58,822 common units were issued during the year ended December 31, 2007. The ultimate number of common units estimated to be issued under the incentive compensation agreements were determined principally by the financial performance of certain Partnership assets for the year ended December 31, 2008 and the market value of the Partnership s common units at December 31, 2008. The incentive compensation agreements also dictate that no individual covered under the agreements shall receive an amount of common units in excess of one percent of the outstanding common units of the Partnership at the date of issuance. Common unit amounts due to any individual covered under the agreements in excess of one percent of the outstanding common units of the Partnership shall be paid in cash.

The Partnership recognized a reduction of compensation expense of $36.3 million, expense of $33.4 million and expense of $4.3 million for the years ended December 31, 2008, 2007 and 2006, respectively, related to the vesting of awards under these incentive compensation agreements. The non-cash compensation expense adjustments for the year ended December 31, 2008 was principally attributable to changes in the Partnership s common unit market price, which was utilized in the calculation of the non-cash compensation expense for these awards, at December 31, 2008 when compared with the common unit market price at earlier periods and adjustments based upon the achievement of actual financial performance targets through December 31, 2008. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method. During the first quarter of 2009, the Partnership expects to issue 348,620 common units to the certain key employees covered under the incentive compensation agreements to fulfill its obligations under the terms of the agreements. No additional common units will be issued with regard to these agreements.

NOTE 15 RELATED PARTY TRANSACTIONS

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of Atlas America. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to their employees who perform services for the Partnership based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by Atlas America based on the number of its employees who devote their time to activities on the Partnership s behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $1.5 million, $5.9 million and $2.3 million for the years ended December 31, 2008, 2007 and 2006, respectively, for compensation and benefits related to their employees. There were no direct reimbursements to the General Partner and its affiliates for the years ended December 31, 2008 and 2007. During the year ended December 31, 2006, direct reimbursements by the Partnership to the General Partner were $15.1 million, including certain costs that have been capitalized by the Partnership. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

Table of Contents

Under an agreement between the Partnership and Atlas Energy, Atlas Energy must construct up to 2,500 feet of sales lines from its existing wells in the Appalachian region to a point of connection to the Partnership s gathering systems. The Partnership must, at its own cost, extend its system to connect to any such lines within 1,000 feet of its gathering systems. With respect to wells to be drilled by Atlas Energy that will be more than 3,500 feet from the Partnership s gathering systems, the Partnership has various options to connect those wells to its gathering systems at its own cost.

NOTE 16 SEGMENT INFORMATION

The Partnership has two reportable segments: natural gas transmission, gathering and processing located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee, and transmission, gathering and processing located in the Mid-Continent area (Mid-Continent) of primarily Oklahoma, northern and western Texas, the Texas Panhandle, Arkansas, southern Kansas and southeastern Missouri. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and transport of natural gas. These reportable segments reflect the way the Partnership manages its operations.

The following summarizes the Partnership s reportable segment data for the periods indicated (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Mid-Continent			
Revenue:			
Natural gas and liquids	$ 1,366,270	$ 759,553	$ 391,356
Transportation, compression and other fees	55,007	48,041	30,653
Other income (loss), net	(55,836)	(174,438)	11,804
Total revenue and other income (loss), net	1,365,441	633,156	433,813
Costs and expenses:			
Natural gas and liquids	1,084,318	586,677	334,299
Plant operating	60,835	34,667	15,722
Transportation and compression	6,637	7,249	5,807
General and administrative	(7,636)	48,332	15,036
Depreciation and amortization	83,694	46,327	19,322
Goodwill and other asset impairment loss	696,204		
Minority interests	(22,781)	3,940	118
Total costs and expenses	1,901,271	727,192	390,304
Segment profit (loss)	(535,830)	$ (94,036)	$ 43,509
Appalachia			
Revenue:			
Natural gas and liquids	$ 3,730	$ 1,565	$
Transportation, compression and other fees affiliates	43,293	33,169	30,189
Transportation, compression and other fees third parties	1,409	575	82
Other income	317	335	608
Total revenue and other income	48,749	35,644	30,879

Table of Contents

Costs and expenses:			
Natural gas and liquids	1,824	847	
Transportation and compression	11,249	6,235	4,946
General and administrative	4,027	6,327	3,767
Depreciation and amortization	6,430	4,655	3,672
Goodwill impairment loss	2,304		
Total costs and expenses	25,834	18,064	12,385
Segment profit	$ 22,915	$ 17,580	$ 18,494
Reconciliation of segment profit (loss) to net income (loss):			
Segment profit (loss):			
Mid-Continent	$ (535,830)	$ (94,036)	$ 43,509
Appalachia	22,915	17,580	18,494
Total segment profit (loss)	(512,915)	(76,456)	62,003
Corporate general and administrative expenses	(4,026)	(6,327)	(3,766)
Interest expense[(1)]	(84,843)	(61,526)	(24,572)
Gain on early extinguishment of debt	19,867		
Net income (loss)	$ (581,917)	$ (144,309)	$ 33,665
Capital Expenditures:			
Mid-Continent	$ 284,432	$ 120,027	$ 65,301
Appalachia	41,502	19,620	18,415
	$ 325,934	$ 139,647	$ 83,716

(1) The Partnership notes that interest expense has not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

	December 31, 2008	2007
Balance Sheet		
Total assets:		
Mid-Continent	$ 2,306,627	$ 2,813,049
Appalachia	114,166	43,860
Corporate other	24,740	20,705
	$ 2,445,533	$ 2,877,614
Goodwill:		
Mid-Continent	$	$ 706,978
Appalachia		2,305
	$	$ 709,283

The following tables summarize the Partnership s total revenues by product or service for the periods indicated (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Natural gas and liquids:			
Natural gas	$ 568,698	$ 264,438	$ 196,182
NGLs	688,623	434,773	169,840
Condensate	57,366	27,269	6,678
Other[(1)]	55,313	34,638	18,656
Total	$ 1,370,000	$ 761,118	$ 391,356

Table of Contents

Transportation, compression and other fees:			
Affiliates	$ 43,293	$ 33,169	$ 30,189
Third parties	56,416	48,616	30,735
Total	$ 99,709	$ 81,785	$ 60,924

(1) Includes treatment, processing, and other revenue associated with the products noted.

NOTE 17 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s term loan and revolving credit facility is guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership s consolidated financial statements as of and for the years ended December 31, 2008 and 2007 include the financial statements of Atlas Pipeline Mid-Continent WestOk, LLC (Chaney Dell LLC) and Atlas Pipeline Mid-Continent WestTex, LLC (Midkiff/Benedum LLC), entities in which the Partnership has 95% interests and were acquired in July 2007 (see Notes 2 and 8). Under the terms of the term loan and revolving credit facility, Chaney Dell LLC and Midkiff/Benedum LLC are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership s stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership s consolidated accounts as of and for the years ended December 31, 2008 and 2007. As Chaney Dell LLC and Midkiff/Benedum LLC were acquired in July 2007, there were no non-guarantor subsidiaries at December 31, 2006 and, as such, the Partnership has not provided supplemental condensed consolidating financial information for this period. For the purpose of the following financial information, the Partnership s investments in its subsidiaries and the guarantor subsidiaries investments in their subsidiaries are presented in accordance with the equity method of accounting (in thousands):

Balance Sheet			**December 31, 2008**		
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$ 7	$ 1,513	$	$	$ 1,520
Accounts receivable affiliates	1,444,812			(1,444,275)	537
Current portion of derivative asset		44,961			44,961
Other current assets		50,385	73,977		124,362
Total current assets	1,444,819	96,859	73,977	(1,444,275)	171,380
Property, plant and equipment, net		923,423	1,099,514		2,022,937
Notes receivable			1,852,928	(1,852,928)	
Equity investments	709,981	194,291		(904,272)	
Intangible assets, net		21,063	172,584		193,647
Goodwill					
Minority interest		32,337			32,337
Other assets, net	23,676	1,374	182		25,232
	$ 2,178,476	$ 1,269,347	$ 3,199,185	$ (4,201,475)	$ 2,445,533
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,362,256	$ 82,019	$ (1,444,275)	$
Current portion of derivative liability		60,396			60,396
Other current liabilities	1,870	66,677	91,251		159,798
Total current liabilities	1,870	1,489,329	173,270	(1,444,275)	220,194
Long-term derivative liability		48,159			48,159
Long-term debt	1,493,427				1,493,427
Other long-term liability		574			574
Partners capital (deficit)	683,179	(268,715)	3,025,915	(2,757,200)	683,179

$ 2,178,476	$ 1,269,347	$ 3,199,185	$ (4,201,475)	$ 2,445,533

Table of Contents

Balance Sheet	December 31, 2007				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 7	$ (6,076)	$ 18,049	$	$ 11,980
Accounts receivable affiliates	2,126,327		45,118	(2,168,111)	3,334
Other current assets		56,356	105,753		162,109
Total current assets	2,126,334	50,280	168,920	(2,168,111)	177,423
Property, plant and equipment, net		714,732	1,033,929		1,748,661
Notes receivable			1,878,626	(1,878,626)	
Equity investments	359,878	984,277		(1,344,155)	
Intangible assets, net		23,516	195,687		219,203
Goodwill		63,441	645,842		709,283
Minority interest		2,163			2,163
Other assets, net	18,228	2,653			20,881
	$ 2,504,440	$ 1,841,062	$ 3,923,004	$ (5,390,892)	$ 2,877,614
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 2,168,111	$	$ (2,168,111)	$
Current portion of derivative liability		110,867			110,867
Other current liabilities	1,088	66,575	77,086		144,749
Total current liabilities	1,088	2,345,553	77,086	(2,168,111)	255,616
Long-term derivative liability		118,646			118,646
Long-term debt	1,229,392				1,229,392
Other long-term liability		574			574
Partners capital (deficit)	1,273,960	(623,137)	3,845,918	(3,222,781)	1,273,960
	$ 2,504,440	$ 1,841,062	$ 3,923,004	$ (5,390,892)	$ 2,877,614

Statement of Operations	Year Ended December 31, 2008				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income (loss), net	$	$ 419,734	$ 1,025,796	$ (31,340)	$ 1,414,190
Total costs and expenses	(64,976)	(553,345)	(1,409,126)	31,340	(1,996,107)
Equity loss	(515,402)	(381,791)		897,193	
Net loss	$ (580,378)	$ (515,402)	$ (383,330)	$ 897,193	$ (581,917)

Statement of Operations	Year Ended December 31, 2007				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income (loss), net	$	$ 260,216	$ 408,584	$	$ 668,800
Total costs and expenses	(61,528)	(470,142)	(281,439)		(813,109)
Equity income (loss)	(82,696)	127,230		(44,534)	
Net income (loss)	$ (144,224)	$ (82,696)	$ 127,145	$ (44,534)	$ (144,309)

108

Table of Contents

Statement of Cash Flows	Year Ended December 31, 2008				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Cashflows from operating activities					
Net loss	$ (580,378)	$ (515,402)	$ (383,330)	$ 897,193	$ (581,917)
Adjustments to reconcile net loss to net cash provided by operating activities:					
Depreciation and amortization		32,315	57,809		90,124
Goodwill and other asset impairment loss		85,089	613,419		698,508
Gain on early extinguishment of debt	(19,867)				(19,867)
Non-cash gain on derivative value, net		(208,813)			(208,813)
Non-cash compensation income	(34,010)				(34,010)
Amortization of deferred financing costs	5,946				5,946
Minority interests		(22,781)			(22,781)
Net distributions paid to minority interest holders		(7,393)			(7,393)
Changes in assets and liabilities net of effects of acquisitions	637,169	30,584	75,988	(722,296)	21,445
Net cash provided by (used in) operating activities	8,860	(606,401)	363,886	174,897	(58,758)
Net cash provided by (used in) investing activities	(350,102)	550,019	(53,030)	(439,831)	(292,944)
Net cash provided by (used in) financing activities	341,242	63,971	(328,905)	264,934	341,242
Net increase (decrease) in cash and cash equivalents		7,589	(18,049)		(10,460)
Cash and cash equivalents, beginning of year	7	(6,076)	18,049		11,980
Cash and cash equivalents, end of year	$ 7	$ 1,513	$	$	$ 1,520

Statement of Cash Flows	Year Ended December 31, 2007				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Cashflows from operating activities					
Net income (loss)	$ (144,224)	$ (82,696)	$ 127,145	$ (44,534)	$ (144,309)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization		27,381	23,601		50,982
Non-cash (gain) loss on derivative value, net		169,424			169,424
Non-cash compensation expense	36,306				36,306
Loss on asset sales and dispositions		805			805
Amortization of deferred financing costs	7,380				7,380
Minority interests		3,940			3,940
Net distributions paid to minority interest holders		(6,103)			(6,103)
Changes in assets and liabilities net of effects of acquisitions	(1,960,837)	44,988	(73,466)	1,970,659	(18,656)
Net cash provided by (used in) operating activities	(2,061,375)	157,739	77,280	1,926,125	99,769
Net cash provided by (used in) investing activities	126,316	(305,168)	(1,899,378)	53,587	(2,024,643)
Net cash provided by financing activities	1,935,059	139,565	1,840,147	(1,979,712)	1,935,059
Net increase (decrease) in cash and cash equivalents		(7,864)	18,049		10,185
Cash and cash equivalents, beginning of year	7	1,788			1,795
Cash and cash equivalents, end of year	$ 7	$ (6,076)	$ 18,049	$	$ 11,980

Table of Contents

NOTE 18 QUARTERLY FINANCIAL DATA (Unaudited)

	Fourth Quarter(1)	Third Quarter(2)	Second Quarter(3)	First Quarter(4)
	(in thousands, except per unit data)			
Year ended December 31, 2008:				
Revenue and other income (loss), net	$ 379,523	$ 582,126	$ 149,155	$ 303,386
Costs and expenses	835,522	383,553	427,826	349,206
Net income (loss)	(455,999)	198,573	(278,671)	(45,820)
Basic net income (loss) per common limited partner unit	$ (9.73)	$ 2.55	$ (7.16)	$ (1.35)
Diluted net income (loss) per common limited partner unit(5)	$ (9.73)	$ 2.43	$ (7.16)	$ (1.35)

(1) Net loss includes a $690.5 million non-cash impairment charge for goodwill and other assets, a $151.8 million non-cash derivative gain, and a $19.9 million gain from the Partnership s repurchase of approximately $60.0 million in face amount of its Senior Notes for an aggregate purchase price of approximately $40.1 million.

(2) Net income includes a $222.0 million non-cash derivative gain and a $71.5 million cash derivative expense from the early termination of certain derivative instruments.

(3) Net loss includes a $181.1 million non-cash derivative loss and a $116.1 million cash derivative expense from the early termination of certain derivative instruments.

(4) Net loss includes a $76.9 million non-cash derivative loss.

(5) For the fourth, second and first quarters of the year ended December 31, 2008, approximately 650,000, 990,000 and 978,000 phantom 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. For the fourth, second and first quarters of the year ended December 31, 2008, potential common limited partner units issuable upon conversion of the Partnership s Class A and Class B cumulative convertible preferred limited partner units were excluded from the computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

	Fourth Quarter(1)	Third Quarter(2)	Second Quarter(3)	First Quarter(4)
	(in thousands, except per unit data)			
Year ended December 31, 2007:				
Revenue and other income (loss), net	$ 213,548	$ 242,300	$ 95,415	$ 117,537
Costs and expenses	315,002	266,798	116,231	115,078
Net income (loss)	(101,454)	(24,498)	(20,816)	2,459
Basic net loss per common limited partner unit	$ (2.69)	$ (0.90)	$ (2.20)	$ (0.14)
Diluted net loss per common limited partner unit(5)	$ (2.69)	$ (0.90)	$ (2.20)	$ (0.14)

(1) Net loss includes a $130.2 million non-cash derivative loss.

(2) Net loss includes an $8.4 million non-cash derivative loss.

(3) Net loss includes a $28.5 million non-cash derivative loss.

(4) Net income includes a $2.3 million non-cash derivative loss.

(5) For the fourth, third, second, and first quarters of the year ended December 31, 2007, approximately 962,000, 619,000, 271,000, and 245,000 phantom 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. For the fourth, third, second, and first quarters of the year ended December 31, 2007,

Table of Contents

potential common limited partner units issuable upon conversion of the Partnership s Class A cumulative convertible preferred limited partner units were excluded from the computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

NOTE 19 SUBSEQUENT EVENT

On January 27, 2009, the Partnership and Sunlight Capital, the holder of the outstanding Class A Preferred Units, agreed to amend certain terms of its existing preferred unit agreement. The amendment (a) increased the dividend yield from 6.5% to 12% per annum, effective January 1, 2009, (b) changed the conversion commencement date from May 8, 2008 to April 1, 2009, (c) changed the conversion price adjustment from $43.00 to $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of the common units, and (d) changed the call redemption price from $53.22 to $27.25. Simultaneously with the execution of the amendment, the Partnership issued Sunlight Capital $15.0 million of its 8.125% senior unsecured notes due 2015 to redeem 10,000 Class A Preferred Units. The Partnership also agreed that it will redeem an additional 10,000 Class A Preferred Units for cash at the liquidation value on April 1, 2009. If Sunlight does not exercise its conversion right on or before June 2, 2009, the Partnership will redeem the then-remaining 10,000 Class A Preferred Units for cash or one-half for cash and one-half for the Partnership s common limited partner units on July 1, 2009.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our General Partner s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2008, our disclosure controls and procedures were effective at the reasonable assurance level.

Management s Report on Internal Control over Financial Reporting

The management of our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of management, including our General Partner s Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of internal control over financial reporting based upon criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control Integrated Framework (COSO framework).

An effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, effectiveness of an internal control system in future periods cannot be guaranteed because the design of any system of internal controls is based in part upon assumptions about the likelihood of future events. There can be no assurance that any control design will succeed in achieving its stated goals under all potential future conditions. Over time certain controls may become inadequate because of changes in business conditions, or the degree of compliance with policies and procedures may deteriorate. As such, misstatements due to error or fraud may occur and not be detected.

Based on our evaluation under the COSO framework, management concluded that internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2008. Grant Thornton LLP, an independent registered public accounting firm and auditors of our consolidated financial statements, has issued an attestation report on the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2008, which is included herein.

There have been no changes in our internal control over financial reporting during the fourth quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Unitholders

Atlas Pipeline Partners, L.P.

We have audited Atlas Pipeline Partners, L.P. s (Partnership) (a Delaware limited partnership) internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Managements Report on Internal Control over Financial Reporting . Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Partnership and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, comprehensive income (loss), partners capital, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated February 27, 2009 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 27, 2009

ITEM 9B. OTHER INFORMATION
None.

Table of Contents

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Our general partner manages our activities. Unitholders do not directly or indirectly participate in our management or operation or have actual or apparent authority to enter into contracts on our behalf or to otherwise bind us. Our general partner will be liable, as general partner, for all of our debts to the extent not paid, except to the extent that indebtedness or other obligations incurred by us are specifically with recourse only to our assets. Whenever possible, our general partner intends to make any of our indebtedness or other obligations with recourse only to our assets.

As set forth in our Partnership Governance Guidelines and in accordance with NYSE listing standards, the non-management members of the managing board meet in executive session regularly without management. The managing board member who will preside at these meetings will rotate each meeting. The purpose of these executive sessions is to promote open and candid discussion among the non-management board members. Interested parties wishing to communicate directly with the non-management members may contact the chairman of the audit committee, Martin Rudolph, at P.O. Box 769, Ardmore, Pennsylvania 19003.

The independent board members comprise all of the members of both of the managing board s committees: the conflicts committee and the audit committee. The conflicts committee has the authority to review specific matters as to which the managing board believes there may be a conflict of interest to determine if the resolution of the conflict proposed by our general partner is fair and reasonable to us. Any matters approved by the conflicts committee are conclusively judged to be fair and reasonable to us, approved by all our partners and not a breach by our general partner or its managing board of any duties they may owe us or the unitholders. The audit committee reviews the external financial reporting by our management, the audit by our independent public accountants, the procedures for internal auditing and the adequacy of our internal accounting controls.

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management or operation. Rather, Atlas America personnel manage and operate our business. Officers of our general partner may spend a substantial amount of time managing the business and affairs of Atlas America and its affiliates and may face a conflict regarding the allocation of their time between our business and affairs and their other business interests.

Managing Board Members and Executive Officers of Our General Partner

The following table sets forth information with respect to the executive officers and managing board members of our general partner:

Name	Age	Position with general partner	Year in which service began
Eugene N. Dubay	60	Chief Executive Officer, President and Managing Board Member	2008
Matthew A. Jones	47	Chief Financial Officer	2005
Edward E. Cohen	70	Chairman of the Managing Board	1999
Jonathan Z. Cohen	38	Vice Chairman of the Managing Board	1999
Tony C. Banks	54	Managing Board Member	1999
Curtis D. Clifford	66	Managing Board Member	2004
Gayle P.W. Jackson	62	Managing Board Member	2005
Martin Rudolph	62	Managing Board Member	2005
Michael L. Staines	59	Managing Board Member	1999

Eugene N. Dubay has been President and Chief Executive Officer of our general partner since January 2009. Mr. Dubay has served as a member of the managing board of our general partner since October 2008, where he served as an independent member until his appointment as President and Chief Executive Officer. Mr. Dubay has been the Chief Executive Officer and President of Atlas Pipeline Holdings since February 2009. Mr. Dubay has been the President and Chief Executive Officer of Atlas Pipeline Mid-Continent, LLC since January 2009. Mr. Dubay was the Chief Operating Officer of Continental Energy Systems LLC (a successor to SEMCO Energy) since 2003. Mr. Dubay has also held positions with ONEOK, Inc. and Southern Union Company and has over 20 years experience in midstream assets and utilities operations, strategic acquisitions, regulatory affairs and finance. Mr. Dubay is a certified public accountant and a graduate of the U.S. Naval Academy.

Matthew A. Jones has been Chief Financial Officer of our general partner and the Chief Financial Officer of Atlas America since March 2005. Mr. Jones has been the Chief Financial Officer of Atlas Holdings GP since January 2006 and a director since February 2006. He has been the Chief Financial Officer and a director of Atlas Energy and Atlas Energy Management since their formation. From 1996 to 2005, Mr. Jones worked in the Investment Banking Group at Friedman Billings Ramsey, concluding as Managing Director. Mr. Jones worked in Friedman Billings Ramsey s Energy Investment Banking Group from 1999 to 2005, and in Friedman Billings Ramsey s Specialty Finance and Real Estate Group from 1996 to 1999. Mr. Jones is a Chartered Financial Analyst.

Edward E. Cohen has been the Chairman of the managing board of our general partner since its formation in 1999. Mr. Cohen was the Chief Executive Officer of our general partner since its formation in 1999 through January 2009. Mr. Cohen has been the Chairman of the Board of Atlas Holdings GP, the general partner of Atlas Pipeline Holdings, since its formation in January 2006. Mr. Cohen served as Chief Executive Officer of Atlas Pipeline Holdings from its formation until February 2009. Mr. Cohen also has been the Chairman of the Board and Chief Executive Officer of Atlas America since its organization in 2000. Mr. Cohen has been the Chairman of the Board and Chief Executive Officer of Atlas Energy and its manager, Atlas Energy Management, Inc.; since their formation in June 2006. In addition, Mr. Cohen has been Chairman of the Board of Directors of Resource America, Inc. (a publicly-traded specialized asset management company) since 1990 and was its Chief Executive Officer from 1988 until 2004, and President from 2000 until 2003; Chairman of the Board of Resource Capital Corp. (a publicly-traded real estate investment trust) since its formation in September 2005; a director of TRM Corporation (a publicly-traded consumer services company) from 1998 to July 2007; and Chairman of the Board of Brandywine Construction & Management, Inc. (a property management company) since 1994. Mr. Cohen is the father of Jonathan Z. Cohen.

Table of Contents

Jonathan Z. Cohen has been Vice Chairman of the managing board of our general partner since our formation in 1999. Mr. Cohen has been the Vice Chairman of the Board of Atlas Holdings GP since its formation in January 2006. Mr. Cohen also has been the Vice Chairman of the Board of Atlas America since its organization in 2000. Mr. Cohen has been Vice Chairman of the Board of Atlas Energy and Atlas Energy Management since their formation in June 2006. Mr. Cohen has been a senior officer of Resource America since 1998, serving as the Chief Executive Officer since 2004, President since 2003 and a director since 2002. Mr. Cohen has been Chief Executive Officer, President and a director of Resource Capital Corp. since its formation in 2005 and was a trustee and secretary of RAIT Financial Trust (a publicly-traded real estate investment trust) from 1997, and its Vice Chairman from 2003, until December 2006. Mr. Cohen is a son of Edward E. Cohen.

Tony C. Banks has been Vice President of Business Development, Performance & Management for FirstEnergy Corporation, a public utility, since March 2007. Mr. Banks joined FirstEnergy Solutions, Inc., a subsidiary of FirstEnergy Corporation, in August 2004 as Director of Marketing and in August 2005 became Vice President of Sales & Marketing. From December 2005 to February 2007, Mr. Banks was Vice President of Business Development for FirstEnergy. Before joining FirstEnergy, Mr. Banks was a consultant to utilities, energy service companies and energy technology firms. From 2000 through 2002, Mr. Banks was President of RAI Ventures, Inc. and Chairman of the Board of Optiron Corporation, an energy technology subsidiary of Atlas America. In addition, Mr. Banks served as President of our general partner during 2000. He was Chief Executive Officer and President of Atlas America from 1998 through 2000. Since October 2000, he has served on the board of directors of TRM Corporation, a provider of ATM services, and he is a member of the audit committee.

Curtis D. Clifford has been the principal of CL4D CO, an energy consulting, marketing and reporting firm since 1998. Mr. Clifford has 42 years experience in the natural gas industry, from exploration, production and gathering to procurement, marketing and utility rates. Currently he works for UtiliTech, Inc., utility and telecommunications specialists in West Lawn, PA where he advises and assists commercial and industrial gas consumers nationwide with procurement activities and utility rate options. He is also president of Amity Manor, Inc. which he founded in 1988 to develop housing for low-income elderly using tax credit financing. Mr. Clifford is a Life Member of the American Society of Civil Engineers and is a registered professional engineer in Pennsylvania.

Gayle P.W. Jackson has been President of Energy Global, Inc., a consulting firm which specializes in corporate development, diversification and government relations strategies for energy companies, since 2004. From 2001 to 2004, Dr. Jackson served as Managing Director of FE Clean Energy Group, a global private equity management firm that invests in energy companies and projects in Asia, Central and Eastern Europe and Latin America. From 1985 to 2001, Dr. Jackson was President of Gayle P.W. Jackson, Inc., a consulting firm that advised energy companies on corporate development and diversification strategies and also advised national and international governmental institutions on energy policy. Dr. Jackson served as Deputy Chairman of the Federal Reserve Bank of St. Louis in 2004-05 and was a member of the Federal Reserve Bank Board from 2000 to 2005. She is a member of the Board of Directors of Ameren Corporation, a publicly-traded public utility holding company, and of the Advisory Panel of Cleantech Private Equity, a London-based private equity buyout fund manager that invests in clean technology companies.

Table of Contents

Martin Rudolph has been the Trustee of the AHP Settlement Trust, a billion dollar trust established to process litigation claims, since 2005. Before that, Mr. Rudolph was a director of tax planning, research and compliance for RSM McGladrey, Inc., a business services firm from 2001 to 2005. From 1990 to 2001, he was a Managing Partner of Rudolph, Palitz LLC, which was merged with RSM McGladrey. Mr. Rudolph is a certified public accountant.

Michael L. Staines has been a member of our managing board since 2000. From 2000 to January 2009, Mr. Staines was our President and Chief Operating Officer. Mr. Staines has been an Executive Vice President of Atlas America since its formation in 2000. Mr. Staines was Senior Vice President of Resource America from 1989 to 2004 and served as a director from 1989 through 2000 and Secretary from 1989 through 1998. Mr. Staines is a member of the Ohio Oil and Gas Association, the Independent Oil and Gas Association of New York and the Independent Petroleum Association of America.

Other Significant Employees

Daniel C. Herz, 32, has been our Senior Vice President of Corporate Development since August 2007. He has also been the Senior Vice President of Corporate Development of Atlas America, Atlas Pipeline Holdings GP and Atlas Energy Resources, LLC since August 2007. Before that, he was Vice President of Corporate Development of Atlas America and Atlas Pipeline Partners GP from December 2004 and of Atlas Pipeline Holdings GP from its formation in January 2006. Mr. Herz joined Atlas America and Atlas Pipeline Partners GP in January 2004. He was an Associate Investment Banker with Banc of America Securities from 2002 to 2003 and an Analyst from 1999 to 2002.

Sean P. McGrath, 37, has been the Chief Accounting Officer of our general partner since May 2005. Mr. McGrath has been the Chief Accounting Officer of Atlas Holdings GP since January 2006. In December, 2008, Mr. McGrath became the Chief Accounting Officer of Atlas America and Atlas Energy Resources, LLC. Mr. McGrath was the Controller of Sunoco Logistics Partners L.P., a publicly-traded partnership that transports, terminals and stores refined products and crude oil, from 2002 to 2005. Mr. McGrath is a Certified Public Accountant.

Lisa Washington, 41, has been the Chief Legal Officer and Secretary of our general partner since November 2005 and a Senior Vice President since October 2008. Ms. Washington has been the Chief Legal Officer and Secretary of Atlas Holdings GP since January 2006 and a Senior Vice President since October 2008. Ms. Washington was a Vice President of Atlas Holdings GP from January 2006 until October 2008. Ms. Washington also has been the Chief Legal Officer and Secretary of Atlas America since November 2005 and a Senior Vice President since July 2008. Ms. Washington was a Vice President of Atlas America from November 2005 until July 2008. She is also the Chief Legal Officer and Secretary of Atlas Energy and Atlas Energy Management, positions she has held since their formation in 2006. Ms. Washington was Vice President of Atlas Energy from 2006 until July 2008, when she became a Senior Vice President. From 1999 to 2005, Ms. Washington was an attorney in the business department of the law firm of Blank Rome LLP.

Table of Contents

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires executive officers and managing board members of our general partner and persons who beneficially own more than 10% of a registered class of our equity securities to file reports of ownership and changes in ownership with the Securities and Exchange Commission and to furnish us with copies of all such reports. Based solely upon our review of reports received by us, or representations from certain reporting persons that no filings were required for those persons, we believe that all of the officers and managing board members of our general partner and persons who beneficially owned more than 10% of our common units complied with all applicable filing requirements during fiscal year 2008, except that Mr. McGrath inadvertently filed one Form 4 late.

Reimbursement of Expenses of Our General Partner and Its Affiliates

Our general partner does not receive any management fee or other compensation for its services apart from its general partner and incentive distributions. We reimburse our general partner and its affiliates, including Atlas America, for all expenses incurred on our behalf. These expenses include the costs of employee, officer and managing board member compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Our general partner allocates the costs of employee and officer compensation and benefits based upon the amount of business time spent by those employees and officers on our business. We reimbursed our general partner and its affiliates $1.5 million for compensation and benefits related to our executive officers during 2008.

Information Concerning the Audit Committee

Our managing board has a standing audit committee. All of the members of the audit committee are independent directors as defined by NYSE rules. The members of the audit committee are Mr. Rudolph, Mr. Clifford, Mr. Banks and Ms. Jackson, with Mr. Rudolph acting as the chairman. Our managing board has determined that Mr. Rudolph is an audit committee financial expert, as defined by SEC rules. The audit committee reviews the scope and effectiveness of audits by the independent accountants, is responsible for the engagement of independent accountants and reviews the adequacy of our internal controls.

Compensation Committee Interlocks and Insider Participation

Neither we nor the managing board of our general partner has a compensation committee. Compensation of the personnel of Atlas America and its affiliates who provide us with services is set by Atlas America and such affiliates. The independent members of the managing board of our general partner, however, do review the allocation of the salaries of such personnel for purposes of reimbursement, discussed in Reimbursement of Expenses of our General Partner and Its Affiliates , above and in Item 11, Executive Compensation.

Mr. Banks was the Chairman of the Board of Optiron Corporation, which was a subsidiary of Atlas America until 2002. At our October 2006 managing board meeting, the managing board determined Mr. Banks to be an independent board member pursuant to NYSE listing standards and Rule 10A-3(b) promulgated under the Securities Exchange Act of 1934. None of the other independent managing board members is an employee or former employee of ours or of our general partner. No executive officer of our general partner is a director or executive officer of any entity in which an independent managing board member is a director or executive officer.

Table of Contents

Code of Business Conduct and Ethics, Partnership Governance Guidelines and Audit Committee Charter

We have adopted a code of business conduct and ethics that applies to the principal executive officer, principal financial officer and principal accounting officer of our general partner, as well as to persons performing services for us generally. We have also adopted Partnership Governance Guidelines and a charter for the audit committee. We will make a printed copy of our code of ethics, our Partnership Governance Guidelines and our audit committee charter available to any unitholder who so requests. Requests for print copies may be directed to us as follows: Atlas Pipeline Partners, L.P., Westpointe Corporate Center, 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108, Attention: Secretary. Each of the code of business conduct and ethics, the Partnership Governance Guidelines and the audit committee charter are posted, and any waivers we grant to our business conduct and ethics will be posted, on our website at www.atlaspipelinepartners.com.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We are required to provide information regarding the compensation program in place as of December 31, 2008, for our general partner s CEO, CFO and the three other most highly-compensated executive officers. In this report, we refer to our general partner s CEO, CFO and the other three most highly-compensated executive officers as our Named Executive Officers or NEOs. This section should be read in conjunction with the detailed tables and narrative descriptions below.

We do not directly compensate our named executive officers. Rather, Atlas America allocates the compensation of our executive officers between activities on behalf of us and activities on behalf of itself and its affiliates based upon an estimate of the time spent by such persons on activities for us and for Atlas America and its affiliates. We reimburse Atlas America for the compensation allocated to us. Because Atlas America employs our NEOs, its compensation committee, comprised solely of independent directors, has been responsible for formulating and presenting recommendations to its Board of Directors with respect to the compensation of our NEOs. The Atlas America compensation committee has also been responsible for administering our employee benefit plans, including our incentive plans.

Compensation Objectives

We believe that our compensation program must support our business strategy, be competitive, and provide both significant rewards for outstanding performance and clear financial consequences for underperformance. We also believe that a significant portion of the NEOs compensation should be at risk in the form of annual and long-term incentive awards that are paid, if at all, based on individual and company accomplishment. Accounting and cost implications of compensation programs are considered in program design; however, the essential consideration is that a program is consistent with our business needs.

Compensation Methodology

The Atlas America compensation committee makes recommendations to the Atlas America board on compensation amounts after the close of its (and our) fiscal year. In the case of base salaries, it recommends the amounts to be paid for that year. In the case of annual bonus and long-term incentive compensation, the committee recommends the amount of awards based on the then concluded fiscal year. Atlas America typically pays cash awards and issues equity awards in February of the following fiscal year. The Atlas America compensation committee has the discretion to recommend the issuance of equity awards at other times during the fiscal year. In addition, some of our NEOs who also perform services for Atlas America and its other publicly-traded subsidiaries, Atlas Energy Resources and Atlas Pipeline Holdings, may receive stock-based awards from Atlas America and these subsidiaries, each of which have delegated compensation decisions to the Atlas America compensation committee because they, like us, do not have their own employees.

Table of Contents

Each year, Atlas America s Chief Executive Officer provides the Atlas America compensation committee with key elements of Atlas America s performance and the NEOs performance as well as recommendations to assist it in determining compensation levels. The Atlas America compensation committee focuses on Atlas America s equity performance, market capitalization, corporate developments, business performance (including production of energy and replacement of reserves) and financial position in recommending the compensation for those NEOs who provided services to both Atlas America and to us.

The Atlas America compensation committee has retained Mercer (US) Inc. to provide information, analyses, and advice regarding executive compensation. At the Atlas America compensation committee s direction, Mercer provided the following services for the committee during fiscal 2008:

- provided on-going advice as needed on the design of Atlas America s annual and long-term incentive plans;
- advised the committee as requested on the performance measures and performance targets for the annual programs by providing an analysis of total shareholder return for a peer group of companies identified by Atlas America and of the metrics of its internal performance review; and
- provided advice in connection with Jonathan Cohen s employment agreement.

Mercer did not provide a peer group or other analysis with respect to compensation levels. In the course of conducting its activities for fiscal 2008, Mercer attended four meetings of the Atlas America compensation committee and presented its findings and recommendations for discussion.

The Atlas America compensation committee has established procedures that it considers adequate to ensure that Mercer s advice remains objective and is not influenced by Atlas America s management. These procedures include: a direct reporting relationship of the Mercer consultant to the chairman of the Atlas America compensation committee; provisions in the engagement letter with Mercer specifying the information, data, and recommendations that can and cannot be shared with management; an annual update to the committee on Mercer s financial relationship with Atlas America, including a summary of the work performed for it during the preceding 12 months; and written assurances from Mercer that, within the Mercer organization, the Mercer consultant who performs services for the committee has a reporting relationship and compensation determined separately from Mercer s other lines of business and from its other work for Atlas America. With the consent of the Atlas America compensation committee chair, Mercer may contact Atlas America s executive officers for information necessary to fulfill its assignment and may make reports and presentations to and on behalf of the Atlas America compensation committee that the executive officers also receive.

Atlas America s Chief Executive Officer provides the Atlas America compensation committee with key elements of both Atlas America s and our company s and the NEOs performance during the year. Atlas America s CEO makes recommendations to the Atlas America compensation committee regarding the

Table of Contents

salary, bonus and incentive compensation component of each NEO s total compensation, including his own. Atlas America s CEO, at the committee s request, may attend committee meetings; however, his role during the meetings is to provide insight into Atlas America s and our company s and the NEOs performance as well as the performance of other comparable companies in the same industry. In making its compensation decisions, the Atlas America compensation committee meets in executive session, without management, both with and without Mercer.

Ultimately, the decisions regarding executive compensation are made by the Atlas America compensation committee after extensive discussion regarding appropriate compensation and may reflect factors and considerations other than the information and advice provided by Mercer and Atlas America s CEO. The Atlas America compensation committee decisions are approved by Atlas America s board of directors.

Elements of our Compensation Program

Our executive officer compensation package includes a combination of annual cash and long-term incentive compensation. Annual cash compensation is comprised of an allocation of base salary plus cash bonus awarded by Atlas America. Long-term incentives consist of a variety of equity awards. Both the annual cash incentives and long-term incentives may be performance-based.

Base Salary

Base salary is intended to provide fixed compensation to the NEOs for their performance of core duties that contributed to the success of Atlas America and us as measured by the elements of corporate performance mentioned above. Base salaries are not intended to compensate individuals for extraordinary performance or for above average company performance.

Annual Incentives

Annual incentives are intended to tie a significant portion of each of the NEO s compensation to Atlas America s annual performance and /or that of one of Atlas America s subsidiaries or divisions for which the officer is responsible. Generally, the higher the level of responsibility of the executive within Atlas America, the greater is the incentive component of that executive s target total cash compensation. The Atlas America compensation committee may recommend awards of performance-based bonuses and discretionary bonuses.

Performance-Based Bonuses The Atlas America Annual Incentive Plan for Senior Executives, which we refer to as the Senior Executive Plan, provides awards for the achievement of predetermined, objective performance measures over a specified 12-month performance period, generally Atlas America s fiscal year. Awards under the Senior Executive Plan are paid in cash. The Senior Executive Plan is designed to permit Atlas America to qualify for an exemption from the $1,000,000 deduction limit under Section 162(m) of the Internal Revenue Code for compensation paid to the NEOs. Notwithstanding the existence of the Senior Executive Plan, the Atlas America compensation committee believes that the interests of Atlas America s stockholders and our unitholders are best served by not restricting its discretion and flexibility in crafting compensation, even if the compensation amounts result in non-deductible compensation expense. Therefore, the committee reserves the right to approve compensation that is not fully deductible.

In March 2008, the Atlas America compensation committee approved 2008 target bonus awards to be paid from a bonus pool. The bonus pool is equal to 18.3% of Atlas America s adjusted distributable cash flow unless the adjusted distributable cash flow includes any capital transaction gains in excess of $50 million, in which case 10% of that excess will be included in the bonus pool. If the adjusted distributable cash flow does not equal at least 95% of the adjusted distributable cash flow for the previous year, no bonuses will be paid. Adjusted distributable cash flow means the sum of (i) cash available for distribution to Atlas America by any of its subsidiaries (regardless of whether such cash is actually distributed), plus (ii) interest income during the year, plus (iii) to the extent not otherwise included in adjusted distributable cash flow, any realized gain on the sale of securities, including securities of a subsidiary, less (iv) Atlas America s stand-alone general and administrative

Table of Contents

expenses for the year (other than non-cash bonus compensation included in general and administrative expenses), and less (v) to the extent not otherwise included in adjusted distributable cash flow, any loss on the sale of securities, including securities of a subsidiary. A return of Atlas America s capital investment in a subsidiary is not intended to be included and, accordingly, if adjusted distributable cash flow includes proceeds from the sale of all or substantially all of the assets of a subsidiary, the amount of such proceeds to be included in adjusted distributable cash flow will be reduced by our basis in the subsidiary. The maximum award payable, expressed as a percentage of Atlas America s estimated 2008 adjusted distributable cash flow, for our NEO participants is as follows: Edward E. Cohen, 6.14%; Jonathan Z. Cohen, 4.37% and Matthew A. Jones, 3.46%. Pursuant to the terms of the Senior Executive Plan, the Atlas America compensation committee has the discretion to recommend reductions, but not increases, in awards under the plan.

We anticipate that in March 2009, the Atlas America compensation committee will adopt a formula governing 2009 targets for bonus awards.

Discretionary Bonuses Discretionary bonuses may be awarded to recognize individual and group performance.

Long-Term Incentives

We believe that our long-term success depends upon aligning our executives and unitholders interests. To support this objective, Atlas America provides our executives with various means to become significant equity holders, including our Long-Term Incentive Plan, which we refer to as our Plan. Our NEOs are also eligible to receive awards under the Atlas America Stock Incentive Plan, which we refer to as the Atlas Plan, the Atlas Energy Resources Long-Term Incentive Plan, which we refer to as the ATN Plan, and the Atlas Pipeline Holdings Long-Term Incentive Plan, which we refer to as the AHD Plan, as appropriate.

Grants under our Plan: The Atlas America compensation committee may recommend grants of equity awards in the form of options and/or phantom units. Only phantom units have been granted under the Plan through December 31, 2008. The phantom units generally vest over four years.

Grants under Other Plans: As described above, our NEOs who perform services for us and one or more of Atlas America s publicly-traded subsidiaries may receive stock-based awards under the Atlas Plan, the ATN Plan or the AHD Plan.

Supplemental Benefits, Deferred Compensation and Perquisites

We do not provide supplemental benefits for executives and perquisites are discouraged. Atlas America does provide a Supplemental Executive Retirement Plan for Messrs. E. Cohen and J. Cohen pursuant to their employment agreements, but none of those benefits or related costs are allocated to us. None of our NEOs have deferred any portion of their compensation.

Employment Agreements

Generally, Atlas America does not favor employment agreements unless they are required to attract or to retain executives to the organization. It entered into an employment agreement with Mr. E. Cohen in 2004 and, in January 2009, it entered into an employment agreement with Mr. J. Cohen. See Employment Agreements and Potential Payments Upon Termination or Change of Control. The Atlas America compensation committee takes termination compensation payable under these agreements into account in determining annual compensation awards, but ultimately its focus is on recognizing each individual s contribution to Atlas America s and our performance during the year.

Determination of 2008 Compensation Amounts

As described above, after the end of our 2008 fiscal year, the Atlas America compensation committee set the base salaries of our NEOs for the 2009 fiscal year and recommended incentive awards based on the prior year s performance. In carrying out its function, the Atlas America compensation committee acted in consultation with Mercer.

In determining the actual amounts to be paid to the NEOs, the Atlas America compensation committee considered both individual and company performance. Our CEO makes recommendations of award amounts based upon the NEOs individual performances as well as the performance of Atlas America s publicly-held subsidiaries for which each NEO provides service; however, the Atlas America compensation committee has the discretion to approve, reject or modify the recommendations. The Atlas America compensation committee noted that our management team had accomplished the following strategic objectives, among others, during fiscal 2008: raised approximately $526 million for us through issuances of equity and senior unsecured notes, increased natural gas processing capacity and achieved record throughput on both our Appalachia and Mid-Continent pipeline systems. In addition, the Atlas America compensation committee reviewed calculations of Atlas America s adjusted distributable cash flow and determined that 2008 adjusted distributable cash flow exceeded the pre-determined minimum threshold of 95% of 2007 adjusted distributable cash flow by more than 50%.

Base Salary. Consistent with its preference for having a significant portion of the NEOs overall compensation package be incentive compensation, Atlas America s CEO did not recommend any increases in salaries for 2009.

Annual Incentives.

Performance-Based Bonuses. The maximum amounts payable to each of our NEOs pursuant to the predetermined percentages was as follows: Edward E. Cohen, $8,644,000; Jonathan Z. Cohen, $6,152,000 and Matthew A. Jones, $4,880,000. As described above, our NEOs substantially outperformed the incentive goals set for them and, under normal circumstances, Atlas America would anticipate awarding substantially increased bonuses for 2008. However, the prevailing economic conditions do not constitute normal circumstances and, accordingly, each NEO will receive awards that are substantially less than the maximum award amounts and less than awards made in fiscal 2007. No part of the bonus awards was allocated to us.

Long-Term Incentives. The Atlas America compensation committee determined that it would not recommend any equity-based awards to our NEOs because it felt that previous awards were adequate.

The following table sets forth the compensation allocation for fiscal years 2008, 2007 and 2006 for our general partner s Chief Executive Officer and Chief Financial Officer and each of our other most highly compensated executive officers whose allocated aggregate salary and bonus (including amounts of salary and bonus foregone to receive non-cash compensation) exceeded $100,000. As required by SEC guidance, the table also discloses awards under the AHD Plan and the Atlas Plan.

Table of Contents

Summary Compensation Table

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($) [1]	Option Awards ($) [2]	Non-Equity Incentive Plan Compensation ($)	All Other Compensation ($)	Total ($)
Edward E. Cohen,	2008	$ 135,000		$ 884,449	$ 1,385,669		$ 257,938[3]	$ 2,663,056
Chairman of the Board and Chief	2007	$ 405,000		$ 1,254,901	$ 509,167	$ 2,250,000	$ 253,212	$ 4,672,280
Executive Officer of Atlas Pipeline GP[8]	2006	$ 180,000	$ 360,000	$ 674,625	$ 84,861		$ 32,300	$ 1,331,786
Matthew A. Jones,	2008	$ 135,000		$ 236,944	$ 760,078		$ 67,713[4]	$ 1,199,734
Chief Financial Officer of Atlas	2007	$ 135,000		$ 356,912	$ 409,128	$ 900,000	$ 75,062	$ 1,875,977
Pipeline GP	2006	$ 105,000	$ 210,000	$ 276,546	$ 16,972		$ 7,650	$ 616,168
Jonathan Z. Cohen,	2008	$ 90,000		$ 503,504	$ 904,868		$ 113,488[5]	$ 1,611,860
Vice Chairman of Atlas Pipeline GP	2007	$ 215,217		$ 807,707	$ 203,667	$ 1,434,783	$ 153,906	$ 2,815,280
	2006	$ 190,000		$ 439,563	$ 48,527		$ 20,400	$ 698,490
Robert R. Firth,	2008	$ 250,000		$ 598,743	$ 443,511		$ 149,468[6]	$ 1,441,721
Former Chief Operating Officer &	2007	$ 250,000		$ 12,370,293	$ 443,393	$ 50,000	$ 118,512	$ 13,232,198
President of Atlas Pipeline Mid-Continent[8]	2006	$ 250,000	$ 150,000	$ 1,806,506	$ 61,100			$ 2,267,606
Michael Staines,	2008	$ 191,250		$ 22,631	$ 19,228		$ 8,460[7]	$ 241,569
Former President[8]	2007	$ 191,250	$ 42,500	$ 61,148	$ 19,198		$ 21,770	$ 336,136

(1) Represents the dollar amount of (i) expense recognized by Atlas Pipeline Holdings for financial statement reporting purposes with respect to phantom units granted under the AHD Plan; and/or (ii) expense we recognized for financial statement reporting purposes with respect to phantom units granted under our Plan and our incentive compensation arrangements, all in accordance with FAS 123R. See note 14 to our consolidated financial statements for an explanation of the assumptions we make for this valuation.

(2) Represents the dollar amount of (i) expense recognized by Atlas America for financial statement reporting purposes with respect to options granted under the Atlas Plan; and/or (ii) expense recognized for financial statement reporting purposes by Atlas Pipeline Holdings for options granted under the AHD Plan, all in accordance with FAS 123R.

(3) Represents payments on DERs of $ 96,838 with respect to the phantom units awarded under our Plan and $161,100 with respect to phantom units awarded under the AHD Plan.

(4) Includes payments on DERs of $ 31,913 with respect to the phantom units awarded under our Plan and $ 35,800 with respect to phantom units awarded under the AHD Plan.

(5) Represents payments on DERs of $48,238 with respect to the phantom units awarded under our Plan and $65,250 with respect to phantom units awarded under the AHD Plan.

(6) Represents payments on DERs of $68,918 with respect to the phantom units awarded under our Plan and our incentive compensation arrangements, and $80,550 with respect to phantom units awarded under the AHD Plan.

(7) Represents payments on DERs with respect to the phantom units awarded under our Plan.

(8) On January 15, 2009, Eugene N. Dubay was appointed Chief Executive Officer and President of Atlas Pipeline GP and as President of Atlas Pipeline Mid-Continent.

No awards were granted to our named executive officers under our Plan or the AHD Plan in 2008.

Employment Agreements and Potential Payments Upon Termination or Change of Control

Edward E. Cohen

In May 2004, Atlas America entered into an employment agreement with Edward E. Cohen, who currently serves as our Chairman, Chief Executive Officer and President. The agreement was amended as of December 31, 2008 to comply with requirements under Section 409A of the Code relating to deferred compensation. As discussed above under Compensation Discussion and Analysis, Atlas America allocates a portion of Mr. Cohen s compensation cost based on an estimate of the time spent by Mr. Cohen on our activities. Atlas America adds 14% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits. The following discussion of Mr. Cohen s employment agreement summarizes those elements of Mr. Cohen s compensation that are allocated in part to us.

Mr. Cohen s employment agreement requires him to devote such time to Atlas America as is reasonably necessary to the fulfillment of his duties, although it permits him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $350,000 per year, which may be increased by the Atlas America compensation committee based upon its evaluation of Mr. Cohen s performance. Mr. Cohen is eligible to receive incentive bonuses and stock option grants and to participate in all employee benefit plans in effect during his period of employment.

The agreement has a term of three years and, until notice to the contrary, the term is automatically extended so that on any day on which the agreement is in effect it has a then-current three-year term. Mr. Cohen s employment agreement was entered into in 2004, around the time that Atlas America was preparing to launch its initial public offering in connection with its spin-off from Resource America, Inc. At that time, it was important to establish a long-term commitment to and from Mr. Cohen as the Chief Executive Officer and President of Atlas America. The rolling three-year term was determined to be an appropriate amount of time to reflect that commitment and was deemed a term that was commensurate with Mr. Cohen s position. The multiples of the compensation components upon termination or a change of control, discussed below, were generally aligned with competitive market practice for similar executives at the time that the agreement was negotiated.

The agreement provides the following regarding termination and termination benefits:

Upon termination of employment due to death, Mr. Cohen s estate will receive (a) a lump sum payment in an amount equal to three times his final base salary and (b) automatic vesting of all stock and option awards.

Atlas America may terminate Mr. Cohen s employment if he is disabled for 180 consecutive days during any 12-month period. If his employment is terminated due to disability, Mr. Cohen will receive (a) a lump sum payment in an amount equal to three times his final base salary, (b) a lump sum amount equal to the COBRA premium cost for continued health coverage, less the premium charge that is paid by Atlas America s employees, during the three years following his termination, (c) a lump sum amount equal to the cost Atlas America would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by our employees, (d) automatic vesting of all stock and option awards and (e) any amounts payable under Atlas America s long-term disability plan.

Table of Contents

Atlas America may terminate Mr. Cohen s employment without cause, including upon or after a change of control, upon 30 days prior written notice. He may terminate his employment for good reason. Good reason is defined as a reduction in his base pay, a demotion, a material reduction in his duties, relocation, his failure to be elected to Atlas America s Board of Directors or Atlas America s material breach of the agreement. Mr. Cohen must provide Atlas America with 30 days notice of a termination by him for good reason within 60 days of the event constituting good reason. Atlas America then would have 30 days in which to cure and, if it does not do so, Mr. Cohen s employment will terminate 30 days after the end of the cure period. If employment is terminated by Atlas America without cause, by Mr. Cohen for good reason or by either party in connection with a change of control, he will be entitled to either (a) if Mr. Cohen does not sign a release, severance benefits under Atlas America s then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to three times his average compensation (defined as the average of the three highest years of total compensation), (ii) a lump sum amount equal to the COBRA premium cost for continued health coverage, less the premium charge that is paid by Atlas America s employees, during the three years following his termination, (iii) a lump sum amount equal to the cost Atlas America would incur for life, disability and accident insurance coverage during the three-year period, less the premium charge that is paid by Atlas America s employees, and (iv) automatic vesting of all stock and option awards.

Mr. Cohen may terminate the agreement without cause with 60 days notice to Atlas America, and if he signs a release, he will receive (a) a lump sum payment equal to one-half of one year s base salary then in effect and (b) automatic vesting of all stock and option awards.

Change of control is defined as:

the acquisition of beneficial ownership, as defined in the Securities Exchange Act of 1933, of 25% or more of Atlas America s voting securities or all or substantially all of Atlas America s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;

Atlas America consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) Atlas America s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless $^1/_2$ of the surviving entity s board were Atlas America s directors immediately before the transaction and Atlas America s chief executive officer immediately before the transaction continues as the chief executive officer of the surviving entity; or (b) Atlas America s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of Atlas America, the surviving entity or, in the case of a division, each entity resulting from the division;

during any period of 24 consecutive months, individuals who were Atlas America Board members at the beginning of the period cease for any reason to constitute a majority of the Atlas America Board, unless the election or nomination for election by Atlas America s stockholders of each new director was approved by a vote of at least $^2/_3$ of the directors then still in office who were directors at the beginning of the period; or

Atlas America s stockholders approve a plan of complete liquidation of winding up of Atlas America, or agreement of sale of all or substantially all of Atlas America s assets or all or substantially all of the assets of Atlas America s primary subsidiaries to an unaffiliated entity.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. In the event that any amounts payable to Mr. Cohen upon termination become subject to any excise tax imposed under Section 4999 of the Code, Atlas America must pay Mr. Cohen an additional sum such that the net amounts retained by Mr. Cohen, after payment of excise, income and withholding taxes, equals the termination amounts payable, unless Mr. Cohen s employment terminates because of his death or disability.

Table of Contents

We anticipate that lump sum termination amounts paid to Mr. Cohen would be allocated to us consistent with past practice and, with respect to payments based on three years of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the prior three-year period. The following table provides an estimate of the value of the benefits to Mr. Cohen if a termination event had occurred as of December 31, 2008.

Reason for termination	Lump sum severance payment	Benefits(1)	Accelerated vesting of stock awards and option awards(2)	Tax gross-up(3)
Death	$ 405,000(4)	$	$ 430,200	$
Disability	405,000(4)	5,763	430,200	
Termination by us without cause	1,612,500(5)	5,763	430,200	
Termination by Mr. Cohen for good reason	1,612,500(5)	5,763	430,200	
Change of control	1,612,500(5)	5,763	430,200	688,696
Termination by Mr. Cohen without cause	67,500(4)		430,200	

(1) Represents rates currently in effect for COBRA insurance benefits for 36 months.

(2) Represents the value of unexercisable option and unvested stock awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable stock on December 31, 2008. The payments relating to stock awards are calculated by multiplying the number of accelerated shares or units by the closing price of the applicable stock on December 31, 2008.

(3) Calculated after deduction of any excise tax imposed under section 4999 of the Code, and any federal, state and local income tax, FICA and Medicare withholding taxes, taking into account the 20% excess parachute payment rate and a 42.65% combined effective tax rate.

(4) Calculated based on Mr. Cohen s 2008 base salary.

(5) Calculated based on Mr. Cohen s average 2008, 2007 and 2006 base salary and bonus.

Jonathan Z. Cohen

In January 2009, Atlas America entered into an employment agreement with Jonathan Z. Cohen, who currently serves as our Vice-Chairman. As discussed above under Compensation Discussion and Analysis, Atlas America allocates a portion of Mr. Cohen s compensation cost based on an estimate of the time spent by Mr. Cohen on our activities. Atlas America adds 14% to the compensation amount allocated to us to cover the costs of health insurance and similar benefits. The following discussion of Mr. Cohen s employment agreement summarizes those elements of Mr. Cohen s compensation that are allocated in part to us.

Mr. Cohen s employment agreement requires him to devote such time to Atlas America as is reasonably necessary to the fulfillment of his duties, although it permits him to invest and participate in outside business endeavors. The agreement provided for initial base compensation of $600,000 per year, which may be increased by the Atlas America based upon its evaluation of Mr. Cohen s performance. Mr. Cohen is eligible to receive incentive bonuses and stock option grants and to participate in all employee benefit plans in effect during his period of employment. The agreement has a term of three years and, until notice to the contrary, the term is automatically extended so that on any day on which the agreement is in effect it has a then-current three-year term. The rolling three-year term and the multiples of the compensation components upon termination or a change of control, discussed below, were generally aligned with competitive market practice for similar executives at the time that the employment agreement was negotiated.

Table of Contents

The agreement provides the following regarding termination and termination benefits:

Upon termination of employment due to death, Mr. Cohen s estate will receive (a) accrued but unpaid bonus and vacation pay and (b) automatic vesting of all equity-based awards.

Atlas America may terminate Mr. Cohen s employment without cause upon 90 days prior notice or if he is physically or mentally disabled for 180 days in the aggregate or 90 consecutive days during any 365-day period and Atlas America s board determines, in good faith based upon medical evidence, that he is unable to perform his duties. Upon termination by Atlas America other than for cause, including disability, or by Mr. Cohen for good reason (defined as any action or inaction that constitutes a material breach by Atlas America of the employment agreement or a change of control), Mr. Cohen will receive either (a) if Mr. Cohen does not sign a release, severance benefits under our then-current severance policy, if any, or (b) if Mr. Cohen signs a release, (i) a lump sum payment in an amount equal to three years of his average compensation (which is defined as his base salary in effect immediately before termination plus the average of the cash bonuses earned for the three calendar years preceding the year in which the termination occurred), less, in the case of termination by reason of disability, any amounts paid under disability insurance provided by us, (ii) monthly reimbursement of any COBRA premium paid by Mr. Cohen, less the amount Mr. Cohen would be required to contribute for health and dental coverage if he were an active employee and (iv) automatic vesting of all equity-based awards.

Atlas America may terminate Mr. Cohen s employment for cause (defined as a felony conviction or conviction of a crime involving fraud, deceit or misrepresentation, failure by Mr. Cohen to materially perform his duties after notice other than as a result of physical or mental illness, or violation of confidentiality obligations or representations contained in the employment agreement). Upon termination by Atlas America for cause or by Mr. Cohen for other than good reason, Mr. Cohen s vested equity-based awards will not be subject to forfeiture.

Change of control is defined as:

the acquisition of beneficial ownership, as defined in the Securities Exchange Act, of 25% or more of Atlas America s voting securities or all or substantially all of Atlas America s assets by a single person or entity or group of affiliated persons or entities, other than an entity affiliated with Mr. Cohen or any member of his immediate family;

Atlas America consummates a merger, consolidation, combination, share exchange, division or other reorganization or transaction with an unaffiliated entity in which either (a) Atlas America s directors immediately before the transaction constitute less than a majority of the board of the surviving entity, unless $^{1}/2$ of the surviving entity s board were our directors immediately before the transaction and Atlas America s Chief Executive Officer immediately before the transaction continues as the Chief Executive Officer of the surviving entity; or (b) Atlas America s voting securities immediately prior to the transaction represent less than 60% of the combined voting power immediately after the transaction of Atlas America, the surviving entity or, in the case of a division, each entity resulting from the division;

during any period of 24 consecutive months, individuals who were Atlas America board members at the beginning of the period cease for any reason to constitute a majority of Atlas America s board, unless the election or nomination for election by Atlas America s stockholders of each new director was approved by a vote of at least $^{2}/3$ of the directors then still in office who were directors at the beginning of the period; or

Table of Contents

Atlas America s stockholders approve a plan of complete liquidation of winding up, or agreement of sale of all or substantially all of Atlas America s assets or all or substantially all of the assets of its primary subsidiaries to an unaffiliated entity.

Termination amounts will not be paid until 6 months after the termination date, if such delay is required by Section 409A. We anticipate that lump sum termination amounts paid to Mr. Cohen would be allocated to us consistent with past practice and, with respect to payments based on three years of compensation, would be allocated to us based on the average amount of time Mr. Cohen devoted to our activities during the prior three-year period. The following table provides an estimate of the value of the benefits to Mr. Cohen if a termination event had occurred as of December 31, 2008.

Reason for termination	Lump sum severance payment	Benefits[(1)]	Accelerated vesting of stock awards and option awards[(2)]
Death			$ 233,850
Termination by us other than for cause (including disability) or by Mr. Cohen for good reason (including a change of control)	$ 1,224,000 (3)		$ 233,850
Termination by us for cause or by Mr. Cohen for other than good reason			

(1) Mr. J. Cohen does not currently receive benefits from Atlas America.

(2) Represents the value of unexercisable option and unvested stock awards disclosed in the Outstanding Equity Awards at Fiscal Year-End Table. The payments relating to option awards are calculated by multiplying the number of accelerated options by the difference between the exercise price and the closing price of the applicable stock on December 31, 2008. The payments relating to stock awards are calculated by multiplying the number of accelerated shares or units by the closing price of the applicable stock on December 31, 2008.

(3) Calculated based on Mr. J. Cohen s average 2008, 2007 and 2006 base salary and bonus.

Robert R. Firth

Atlas America entered into an employment agreement in July 2004 with Robert R. Firth in connection with our acquisition of Spectrum, pursuant to which he serves as president of our Mid-Continent operations. The agreement expired on July 16, 2007. The agreement provides for initial base compensation of $200,000 per year, subject to increase, but not decrease, at the discretion of the board of directors of Atlas America. Mr. Firth is eligible to receive discretionary bonuses in the discretion of the Atlas America board. Mr. Firth is also entitled to receive awards under our executive group incentive program, described below. Mr. Firth s current allocation under this program is 40%, but the allocation is subject to change at Mr. Firth s election.

The agreement restricts Mr. Firth, for 18 months following the expiration of his employment agreement, from engaging in any business in direct competition with Atlas America and located in the counties in which Atlas Pipeline Mid-Continent, LLC maintains operations or in which Mr. Firth worked; soliciting any of Atlas America s clients; recruiting, soliciting or hiring any of Atlas America s employees or consultants; or inducing any employee or consultant to terminate its relationship with Atlas America. Pursuant to the terms of the grant agreements related to Mr. Firth s stock and option awards, upon Mr. Firth s death or disability, the stock and options awards will automatically vest.

Our Long-Term Incentive Plan

We have a Long-Term Incentive Plan for officers, employees and non-employee managers of our general partner and officers and employees of our general partner s affiliates, consultants and joint venture partners who perform services for us or in furtherance of our business. Our Plan is administered by the Atlas America compensation committee, under delegation from our general partner s managing board which sets the terms of awards under it. Under our Plan, the compensation committee may make awards of either phantom units or options covering an aggregate of 435,000 common units.

A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, at the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the compensation committee may grant a participant the right, which we refer to as a DER, to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions we make on a common unit during the period the phantom unit is outstanding.

An option entitles the grantee to purchase our common units at an exercise price determined by the compensation committee, which may be less than, equal to or more than the fair market value of our common units on the date of grant. The compensation committee will also have discretion to determine how the exercise price may be paid.

Each non-employee manager of our general partner is awarded the lesser of 500 phantom units, with DERs, or that number of phantom units, with DERs, equal to $15,000 divided by the then fair market value of a common unit for each year of service on the managing board beginning when the plan is adopted by our unitholders. Up to 10,000 phantom units may be awarded to non-employee managers. Except for phantom units awarded to non-employee managers of our general partner, the compensation committee will determine the vesting period for phantom units and the exercise period for options. Phantom units awarded to non-employee managers will generally vest over a 4-year period at the rate of 25% per year. Both types of awards will automatically vest upon a change of control, defined as follows:

Atlas Pipeline Partners GP (or an affiliate of Atlas America) ceasing to be our general partner;

a merger, consolidation, share exchange, division or other reorganization or transaction of us, our general partner or a direct or indirect parent of our general partner with any entity, other than a transaction which would result in the voting securities of the us, our general partner or its parent, as appropriate, outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity) at least 60% of the combined voting power immediately after such transaction of the surviving entity s outstanding securities or, in the case of a division, the outstanding securities of each entity resulting from the division;

the equity holders of us or a direct or indirect parent of our general partner approve a plan of complete, liquidation or winding-up or an agreement for the sale or disposition (in one transaction or a series of transactions) of all or substantially all of our or such parent s assets; or

during any period of 24 consecutive months, individuals who at the beginning of such period constituted the board of directors of Atlas Pipeline GP or a direct or indirect parent of our general partner (including for this purpose any new director whose election or nomination for election or appointment was approved by a vote of at least $^{2}/_{3}$ of the directors then still in office who were directors at the beginning of such period) cease for any reason to constitute at least a majority of the board or, in the case of a spin off of the parent, if Edward E. Cohen and Jonathan Z. Cohen cease to be directors of the parent.

If a grantee terminates employment, the grantee s award will be automatically forfeited unless the compensation committee provides otherwise. However, the award will automatically vest if the reason for the termination is the participant s death or disability. Common units to be delivered upon vesting of phantom units or upon exercise of options may be newly issued units, units acquired in the open market or from any of our affiliates, or any combination of these sources at the discretion of the compensation committee. If we issue new common units upon vesting of the phantom units or upon the exercise of options, the total number of common units outstanding will increase. We filed a registration statement with the SEC in order to permit participants to publicly re-sell any common units received by them under the plan.

The compensation committee may terminate our Plan at any time with respect to any of the common units for which it has not made a grant. In addition, the compensation committee may amend our Plan from time to time, including, subject to applicable law or the rules of the principal securities exchange on which our common units are traded, increasing the number of common units with respect to which it may grant awards, provided that, without the participant s consent, no change may be made in any outstanding grant that would materially impair the rights of the participant. NYSE rules would require us to obtain unitholder approval for all material amendments to our Plan, including amendments to increase the number of common units issuable under it.

Executive Group Incentive Program

In connection with our acquisition of Spectrum, and our retention of certain Spectrum s executive officers, we created an executive group incentive program for our Mid-Continent operations. Eligible participants in the executive group incentive program are Robert R. Firth, David D. Hall and such other of our officers as agreed upon by Messrs. Firth and Hall and the managing board of our general partner. The executive group incentive program has three award components: base incentive, additional incentive and acquisition look-back incentive, as follows:

- Base incentive. An award of 29,411 of our common units on the day following the earlier to occur of the filing of our quarterly report on Form 10-Q for the quarter ending September 30, 2007 or a change in control if the following conditions were met:
  - distributable cash flow (defined as earnings before interest, depreciation, amortization and any allocation of overhead from Atlas Pipeline, less maintenance capital expenditures on the Spectrum assets) generated by the Spectrum assets, as expanded since Atlas Pipeline s acquisition of them, has averaged at least 10.7%, on an annualized basis, of average gross long term assets (defined as total assets less current assets, closing costs associated with any acquisition and plus accumulated depreciation, depletion and amortization) over the 13 quarters ending September 30, 2007; and
  - there having been no more than 2 quarters with distributable cash flow of less than 7%, on an annualized basis, of gross long term assets for that quarter.

We issued 29,411 common units under this component.

- Additional incentive. An award of common units, promptly upon the filing of our September 30, 2007 Form 10-Q, in an amount equal to 7.42% of the base incentive for each 0.1% by which average annual distributable cash flow exceeds 10.7% of average gross long term assets, as described above, up to a maximum of an additional 29,411 common units. 29,411 common units were issued under this component.

Table of Contents

Acquisition look-back incentive. If the requirements for the base incentive have been met, an award of Atlas Pipeline common units determined by dividing (x) 1.5% of the imputed value of the Elk City system plus 1.0% of the imputed value of all Mid-Continent acquisitions completed before December 31, 2007 that were identified by members of the Mid-Continent executive group by (y) the average closing price of Atlas Pipeline common units for the 5 trading days before December 31, 2008. Imputed value of an acquisition is equal to the distributable cash flow generated by the acquired entity during the 12 months ending December 31, 2008 divided by the yield. Yield is determined by dividing (i) the sum of Atlas Pipeline s quarterly distributions for the quarter ending December 31, 2008 multiplied by 4 by (ii) the closing price of its common units on December 31, 2008. We expect to award 348,620 common units under this component in March 2009.

AHD Plan

The AHD Plan provides performance incentive awards to officers, employees and board members and employees of its affiliates, consultants and joint-venture partners who perform services for Atlas Pipeline Holdings. The AHD Plan is administered by Atlas America s compensation committee under delegation from the Atlas Pipeline Holdings board. The compensation committee may grant awards of either phantom units or unit options for an aggregate of 2,100,000 common limited partner units.

Partnership Phantom Units. A phantom unit entitles a participant to receive an Atlas Pipeline Holdings common unit upon vesting of the phantom unit or, at the discretion of the compensation committee, cash equivalent to the then fair market value of a common unit. In tandem with phantom unit grants, the compensation committee may grant a DER. The compensation committee determines the vesting period for phantom units. Through December 31, 2008, phantom units granted under the AHD Plan generally vest 25% on the third anniversary of the date of grant and 75% on the fourth anniversary of the date of grant.

Partnership Unit Options. A unit option entitles a participant to receive a common unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option may be equal to or more than the fair market value of a common unit as determined by the compensation committee on the date of grant of the option. The compensation committee determines the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Through December 31, 2008, unit options generally will vest 25% on the third anniversary of the date of grant and 75% on the fourth anniversary of the date of grant.

The vesting of both types of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the compensation committee, although no awards currently outstanding contain any such provision. Awards will automatically vest upon a change of control, as defined in the AHD Plan.

Atlas Plan

The Atlas Plan authorizes the granting of up to 4.5 million shares of Atlas common stock to its employees, affiliates, consultants and directors in the form of incentive stock options, non-qualified stock options, stock appreciation rights (SARs), restricted stock and deferred units. SARs represent a right to receive cash in the amount of the difference between the fair market value of a share of Atlas America common stock on the exercise date and the exercise price, and may be free-standing or tied to grants of options. A deferred unit represents the right to receive one share of Atlas common stock upon vesting. Awards under the Atlas Plan generally become exercisable as to 25% each anniversary after the date of grant, except that deferred units awarded to our non-executive board members vest 33 $^{1}/3$% on the second, third and fourth anniversaries of the grant, and expire not later than ten years after the date of grant. Units will vest sooner upon a change in control of Atlas America or death or disability of a grantee, provided the grantee has completed at least six months service.

Table of Contents

As required by SEC guidelines, the following table disclosed awards under our Plan as well as under the AHD Plan and the Atlas Plan.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END TABLE

	Option Awards				Stock Awards	
Name	**Number of Securities Underlying Unexercised Options (#) Exercisable**	**Number of Securities Underlying Unexercised Options (#) Unexercisable**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock That Have Not Vested (#)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)**
Edward E. Cohen	1,012,500 (1)		$ 11.32	7/1/2015		$
	75,000 (2)	225,000 (3)	$ 32.53	1/29/2018	15,000 (4)	$ 90,000 (5)
		500,000 (6)	$ 22.56	11/10/2016	90,000 (7)	$ 340,200 (8)
Matthew A. Jones	202,500 (9)	67,500 (10)	$ 11.32	7/1/2015		$
	30,000 (11)	90,000 (12)	$ 32.53	1/29/2018	6,250 (13)	$ 37,500 (5)
		100,000 (14)	$ 22.56	11/10/2016	20,000 (15)	$ 75,600 (8)
Jonathan Z. Cohen	675,000 (16)		$ 11.32	7/1/2015		$
	60,000 (17)	180,000 (18)	$ 32.53	1/29/2018	10,625 (19)	$ 63,750 (5)
		200,000 (20)	$ 22.56	11/10/2016	45,000 (21)	$ 170,100 (8)
Robert R. Firth	16,875 (22)	16,875 (23)	$ 11.32	7/1/2015	12,250 (24)	$ 73,500 (5)
		360,000 (25)	$ 22.56	11/10/2016	45,000 (26)	$ 170,100(8)
Michael L. Staines	12,656 (27)	4,220 (28)	$ 11.32	7/1/2015	1,000 (29)	$ 6,000(5)

(1) Represents 1,012,500 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America, which vested immediately. Reflects a 3-for-2 stock split which was effected on June 2, 2008.

(2) Represents 75,000 options to purchase Atlas America stock, granted on 1/29/08. Reflects a 3-for-2 stock split which was effected on June 2, 2008.

(3) Represents options to purchase Atlas America stock, which vest as follows: 1/29/09 75,000, 1/29/09 75,000 and 1/29/10 75,000.

(4) Represents our phantom units, which vest as follows: 3/16/09 5,000; 11/1/09 5,000 and 11/1/10 5,000.

(5) Based on closing market price of our common units on December 31, 2008 of $ 6.00.

(6) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 125,000 and 11/10/10 375,000.

(7) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 22,500 and 11/10/10 67,500.

(8) Based on closing market price of Atlas Pipeline Holdings common units on December 31, 2008 of $ 3.78.

(9) Represents 202,500 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America. Reflects a 3-for-2 stock split which was effected on June 2, 2008.

(10) Represents options to purchase Atlas America stock, which vest as follows: 7/1/09 67,500.

(11) Represents 30,000 options to purchase Atlas America stock, granted on 1/29/08. Reflects a 3-for-2 stock split which was effected on June 2, 2008.

(12) Represents options to purchase Atlas America stock, which vest as follows: 1/29/09 30,000, 1/29/09 30,000 and 1/29/10 30,000.

(13) Represents our phantom units, which vest as follows: 3/16/09 3,750; 11/1/09 1,250 and 11/1/10 1,250.

(14) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 25,000 and 11/10/10 75,000.

(15) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 5,000 and 11/10/10 15,000.

Table of Contents

(16) Represents 675,000 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America, which vested immediately. Reflects a 3-for-2 stock split which was effected on June 2, 2008.
(17) Represents 60,000 options to purchase Atlas America stock, granted on 1/29/08. Reflects a 3-for-2 stock split which was effected on June 2, 2008.
(18) Represents options to purchase Atlas America stock, which vest as follows: 1/29/09 60,000, 1/29/09 60,000 and 1/29/10 60,000.
(19) Represents our phantom units, which vest as follows: 3/16/09 3,125; 11/1/09 3,750 and 11/1/10 3,750.
(20) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 50,000 and 11/10/10 150,000.
(21) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 11,250 and 11/10/10 33,750.
(22) Represents 16,875 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America. Reflects a 3-for-2 stock split which was effected on June 2, 2008.
(23) Represents options to purchase Atlas America stock, which vest as follows: 7/1/09 16,875.
(24) Represents our phantom units, which vest as follows: 1/24/09 5,750, 3/16/09 750 and 1/24/10 5,750.
(25) Represents Atlas Pipeline Holdings options, which vest as follows: 11/10/09 90,000 and 11/10/10 270,000.
(26) Represents Atlas Pipeline Holdings phantom units, which vest as follows: 11/10/09 11,250 and 11/10/10 33,750.
(27) Represents 12,656 options to purchase Atlas America stock, granted on 7/1/05 in connection with its spin-off from Resource America. Reflects a 3-for-2 stock split which was effected on June 2, 2008.
(28) Represents options to purchase Atlas America stock, which vest as follows: 7/1/09 4,220.
(29) Represents our phantom units, which vest as follows: 3/16/09 1,000.

2008 OPTION EXERCISES AND STOCK VESTED TABLE

	Stock Awards	
Name	Number of Shares Acquired on Vesting	Value Realized on Vesting ($)
Edward E. Cohen	16,250(1)	$ 557,500
Matthew A. Jones	5,000(1)	$ 176,562
Jonathan Z. Cohen	10,625(1)	$ 353,100
Robert R. Firth	6,500(2)	$ 280,892
Michael L. Staines	3,000(1)	$ 124,160

(1) Represents awards under our Plan.

(2) Represents options to purchase Atlas America common stock.

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Tony C. Banks	$ 35,000	$ (5,862) (3)	$ 3,222	$ 32,360
Curtis D. Clifford	$ 35,000	$ (4,458) (4)	$ 3,344	$ 33,885
Eugene N. Dubay	$ 7,514(5)	$ 391(6)	$ 480	$ 8,384
Gayle P.W. Jackson	$ 35,000	$ (6,120) (7)	$ 3,204	$ 32,084
Martin Rudolph	$ 35,000	$ (6,120) (7)	$ 3,204	$ 32,084

Table of Contents

(1) Represents the dollar amount of expense we recognized for financial statement reporting purposes with respect to phantom units granted under our Plan in accordance with FAS 123R.

(2) Represents payments on DERs with respect to the phantom units awarded under our Plan.

(3) Represents 844 phantom units outstanding for Mr. Banks. The shares vest one-quarter on each of the first through fourth anniversaries of the date of grant. The vesting schedule for the units is as follows: 2/11/10 254; 2/11/211 245; and 2/11/12 84. Also includes an award of 335 phantom units on 2/11/08 with a fair market value of $44.72.

(4) Represents 863 phantom units outstanding for Mr. Clifford. The shares vest one-quarter on each of the first through fourth anniversaries of the date of grant. The vesting schedule for the shares is as follows: 5/10/09 359; 5/10/10 253 5/10/11 161; and 5/10/12 90. Also includes an award of 345 phantom units on 5/10/08 with a fair market value of $43.42.

(5) Represents a pro-rated portion of the managing board member fee for Mr. Dubay, who began service in July, 2008.

(6) Represents 500 phantom units outstanding for Mr. Dubay which were granted to Mr. Dubay on 10/14/08 with a fair market value of $21.66. The shares vest one-quarter on each of the first through fourth anniversaries of the date of grant. The vesting schedule for the shares is as follows: 10/14/09 125; 10/14/10 125; 10/14/11 125; and 10/14/12 125.

(7) Represents 879 phantom units outstanding for each of Ms. Jackson and Mr. Rudolph. The shares vest one-quarter on each of the first through fourth anniversaries of the date of grant. The vesting schedule for the shares is as follows: 3/17/09 341; 3/17/10 264; 3/17/11 176; 3/17/12 98. Also includes an award of 383 on 3/17/08 with a fair market value of $39.12.

Our general partner does not pay additional remuneration to officers or employees of Atlas America who also serve as managing board members. In fiscal year 2008, each non-employee managing board member received an annual retainer of $35,000 in cash and an annual grant of phantom units with DERs in an amount equal to the lesser of 500 units or $15,000 worth of units (based upon the market price of our common units) pursuant to our Long-Term Incentive Plan. In addition, our general partner reimburses each non-employee board member for out-of-pocket expenses in connection with attending meetings of the board or committees. We reimburse our general partner for these expenses and indemnify our general partner s managing board members for actions associated with serving as managing board members to the extent permitted under Delaware law.

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

The following table sets forth the number and percentage of shares of common stock owned, as of February 23, 2009, by (a) each person who, to our knowledge, is the beneficial owner of more than 5% of the outstanding shares of common stock, (b) each of the members of the managing board of our general partner, (c) each of the executive officers named in the Summary Compensation Table in Item 11, and (d) all of the named executive officers and board members as a group. This information is reported in accordance with the beneficial ownership rules of the Securities and Exchange Commission under which a person is deemed to be the beneficial owner of a security if that person has or shares voting power or investment power with respect to such security or has the right to acquire such ownership within 60 days. Unless otherwise indicated in footnotes to the table, each person listed has sole voting and dispositive power with respect to the securities owned by such person. The address of our general partner, its executive officers and managing board members is 1550 Coraopolis Heights Road, Moon Township, Pennsylvania 15108.

Name of Beneficial Owner	Common Units	Percent of Class
Members of the Managing Board		
Edward E. Cohen	73,884(1)	*
Jonathan Z. Cohen	45,834(2)	*
Eugene N. Dubay	2,000	*
Matthew A. Jones	17,500(3)	*
Tony C. Banks	995	*

Curtis D. Clifford	1,023	*
Gayle P.W. Jackson	832(4)	*
Martin Rudolph	1,332(4)	*
Michael L. Staines	12,000(5)	*
Managing Board Members as a group (9 persons)	162,755	*
Other Owners of More than 5% of Outstanding Units		
Atlas Pipeline Holdings, L.P.	4,113,227	8.95%
Leon Cooperman	4,574,318(6)	9.90%
Kayne Anderson Capital Advisors, L.P.	2,565,318(7)	5.58%
Swank Capital, LLC	2,370,800(8)	5.16%
Elliott Associates, L.P.	3,189,792(9)	6.50%

* Less than 1%.

(1) This amount includes 5,000 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(2) This amount includes 3,125 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(3) This amount includes 3,750 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(4) This amount includes 341 phantom units which vest in 60 days and which, upon vesting, may be converted into an equal number of our common units or into their then fair market value in cash.

(5) This amount includes 1,000 phantom units which vest in 60 days and which, upon vesting, convert into an equal number of our common units.

(6) This information is based upon a Schedule 13G which was filed with the SEC on February 4, 2009. The address for Mr. Cooperman is 88 Pine Street, Wall Street Plaza 31st Floor, New York, NY 10005.

(7) This information is based upon a Schedule 13G/A which was filed with the SEC on February 4, 2009. The address for Kayne Anderson is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, CA 90067.

(8) This information is based upon a Schedule 13G which was filed with the SEC on February 17, 2009. The address for Swank Capital, LLC is 330 Oak Lawn Avenue, Suite 650, Dallas, TX 75219.

(9) This information is based upon a Schedule 13G/A which was filed with the SEC on February 10, 2009. The address for Elliott Associates is 712 Fifth Avenue, New York, NY 10019.

Equity Compensation Plan Information

The following table contains information about our Plan as of December 31, 2008:

Plan category		(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	phantom units	126,565	n/a	155,009

Table of Contents

The following table contains information about the AHD Plan as of December 31, 2008:

Plan category		(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	phantom units	226,300	n/a	
Equity compensation plans approved by security holders	unit options	1,215,000	$ 22.56	
Equity compensation plans approved by security holders	Total	1,441,300		657,650

The following table contains information about the Atlas Plan as of December 31, 2008:

Plan category		(a) Number of securities to be issued upon exercise of equity instruments	(b) Weighted-average exercise price of outstanding equity instruments	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	restricted units	12,232	n/a	
Equity compensation plans approved by security holders	options	3,495,351	$ 16.97	
Equity compensation plans approved by security holders	Total	3,507,583		838,160

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

We do not directly employ any persons to manage or operate our business. These functions are provided by our general partner and employees of Atlas America. Our general partner does not receive a management fee in connection with its management of our operations, but we reimburse our general partner and its affiliates for compensation and benefits related to Atlas America employees who perform services to us, based upon an estimate of the time spent by such persons on our activities. Other indirect costs, such as rent for offices, are allocated to us by Atlas America based on the number of its employees who devote substantially all of their time to our activities. Our partnership agreement provides that our general partner will determine the costs and expenses that are allocable to us in any reasonable manner determined at its sole discretion. We reimbursed our general partner and its affiliates $1.5 million for the year ended December 31, 2008 for compensation and benefits related to their employees. Our general partner believes that the method utilized in allocating costs to us is reasonable.

Our omnibus agreement and the natural gas gathering agreements with Atlas America and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), were not the result of arms-length negotiations and, accordingly, we cannot assure you that we could have obtained more favorable terms from independent third parties similarly situated. However, since these agreements principally involve the imposition of obligations on Atlas America and its affiliates, we do not believe that we could obtain similar agreements from independent third parties.

The managing board of our general partner has determined that Messrs. Curtis Clifford, Tony Banks, Martin Rudolph and Dr. Gayle P.W. Jackson each satisfy the requirement for independence set out in Section 303A.02 of the rules of the New York Stock Exchange (the NYSE) including those set forth in Rule 10A-3(b)(1) of the Securities Exchange Act, and meet the definition of an independent member set forth in our Partnership Governance Guidelines. In making theses determinations, the managing board reviewed information from each of these non-management board members concerning all their respective relationships with us and analyzed the materiality of those relationships.

Table of Contents

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees recognized by us during the years ended December 31, 2008 and 2007 by our principal accounting firm, Grant Thornton LLP, are set forth below:

	2008	2007
Audit fees [1]	$ 1,943,280	$ 1,642,981
Audit related fees		
Tax fees [2]	165,750	180,568
Total aggregate fees billed	$ 2,109,030	$ 1,823,549

(1) Represents the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP for the audit of our annual financial statements and the review of financial statements included in Form 10-Q. The fees are for services that are normally provided by Grant Thornton LLP in connection with statutory or regulatory filings or engagements.

(2) Represents the aggregate fees recognized in each of the last two years for professional services rendered by Grant Thornton LLP for tax compliance, tax advice, and tax planning.

Audit Committee Pre-Approval Policies and Procedures

Pursuant to its charter, the audit committee of the managing board of our general partner is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent auditors. All of such services and fees were pre-approved during 2008 and 2007.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

(1) Financial Statements

The financial statements required by this Item 15(a)(1) are set forth in Item 8.

(2) Financial Statement Schedules

No schedules are required to be presented.

(3) Exhibits:

Exhibit No.	Description
3.1	Certificate of Limited Partnership[1]
3.2(a)	Second Amended and Restated Agreement of Limited Partnership[2]
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership[3]

3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership[4]
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership[6]

3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership[7]
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership[11]
3.3	Second Amended and Restated Certificate of Designation for 12% Cumulative Convertible Preferred Units[5]
3.4	Certificate of Designation for 12% Cumulative Convertible Class B Preferred Units[11]
4.1	Common unit certificate[1]
4.2	8 $^{1}/8$% Senior Notes Indenture dated December 20, 2005[12]
4.3	8 $^{3}/4$% Senior Notes Indenture dated June 27, 2008[9]
10.1(a)	Revolving Credit and Term Loan Agreement dated July 27, 2007[4]
10.1(b)	Amendment No. 1 and Agreement to the Revolving Credit and Term Loan Agreement, dated June 12, 2008[7]
10.1(c)	Increase Joinder dated June 27, 2008[10]
10.2	Common Unit Purchase Agreement dated June 17, 2008, by and among Atlas Pipeline Partners, L.P., Atlas America, Inc. and Atlas Pipeline Holdings, L.P.[8]
10.3	8 $^{3}/4$% Senior Notes Purchase Agreement dated June 24, 2008, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corp., the subsidiary guarantors and Wachovia Capital Markets LLC, as representative of the several initial purchasers[9]
10.4	Registration Rights Agreement dated June 27, 2008, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corp., the subsidiary guarantors and Wachovia Capital Markets LLC, as representative of the several initial purchasers[9]
10.5	Class B Preferred Unit Purchase Agreement dated December 30, 2008, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P.[11]
10.6	Registration Rights Agreement dated December 30, 2008, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P. [11]
10.7	Purchase Agreement dated as of January 27, 2009, between Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, Sunlight Capital Partners, LLC, Elliott Associates, L.P. and Elliott International, L.P. [5]
10.8	Purchase Option Agreement between Atlas Pipeline Mid-Continent WestTex, LLC and Pioneer Natural Resources USA, Inc. dated July 27, 2007[4]

10.9	Long-Term Incentive Plan
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of Registrant
23.1	Consent of Grant Thornton LLP
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(5) Previously filed as an exhibit to current report on Form 8-K on January 29, 2009.
(6) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
(7) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
(8) Previously filed as an exhibit to current report on Form 8-K on June 23, 2008.
(9) Previously filed as an exhibit to current report on Form 8-K on June 27, 2008.
(10) Previously filed as an exhibit to current report on Form 8-K on July 3, 2008.
(11) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
(12) Previously filed as an exhibit to current report on Form 8-K on December 21, 2005.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATLAS PIPELINE PARTNERS, L.P.

By: Atlas Pipeline Partners GP, LLC,
its General Partner

March 2, 2009

By: /s/ EUGENE N. DUBAY
Chief Executive Officer, President and Managing
Board Member of the General Partner

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of March 2, 2009.

/s/ EDWARD E. COHEN Edward E. Cohen	Chairman of the Managing Board of the General Partner
/s/ JONATHAN Z. COHEN Jonathan Z. Cohen	Vice Chairman of the Managing Board of the General Partner
/s/ EUGENE N. DUBAY Eugene N. Dubay	Chief Executive Officer, President and Managing Board Member of the General Partner
/s/ MATTHEW A. JONES Matthew A. Jones	Chief Financial Officer of the General Partner
/s/ SEAN P. MCGRATH Sean P. McGrath	Chief Accounting Officer of the General Partner
/s/ TONY C. BANKS Tony C. Banks	Managing Board Member of the General Partner
/s/ CURTIS D. CLIFFORD Curtis D. Clifford	Managing Board Member of the General Partner
/s/ GAYLE P.W. JACKSON Gayle P.W. Jackson	Managing Board Member of the General Partner
/s/ MARTIN RUDOLPH Martin Rudolph	Managing Board Member of the General Partner
/s/ MICHAEL L. STAINES Michael L. Staines	Managing Board Member of the General Partner