

ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 06, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from _____ to _____

Commission file number: 1-14998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

| | |
|---|--|
| DELAWARE (State or other jurisdiction of | 23-3011077 (I.R.S. Employer |
| incorporation or organization) | Identification No.) |
| Park Place Corporate Center One 1000 Commerce Drive, 4th Floor Pittsburgh, Pennsylvania (Address of principal executive office) | 15275-1011 (Zip code) |
| Registrant's telephone number, including area code: (877) 950-7473 | |

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

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

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

Large accelerated filer Accelerated filer

Non-accelerated filer (Do not check if a smaller reporting company) Smaller reporting company

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

The number of common units of the registrant outstanding on August 4, 2014 was 82,191,639.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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ON FORM 10-Q

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Glossary of Terms

Definitions of terms and acronyms generally used in the energy industry and in this report are as follows:

| | |
|--------------------------------|---|
| BPD | Barrels per day. Barrel measurement for a standard US barrel is 42 gallons. Crude oil and condensate are generally reported in barrels. |
| BTU | British thermal unit, a basic measure of heat energy |
| Condensate | Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing. |
| EBITDA | Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is a non-GAAP measure. |
| FASB | Financial Accounting Standards Board |
| Fractionation | The process used to separate an NGL stream into its individual components. |
| GAAP | Generally Accepted Accounting Principles |
| G.P. | General Partner or General Partnership |
| Keep-Whole | A contract with a natural gas producer whereby the plant operator pays for or returns gas having an equivalent BTU content to the gas received at the well-head. |
| L.P. | Limited Partner or Limited Partnership |
| MCF | Thousand cubic feet |
| MCFD | Thousand cubic feet per day |
| MMBTU | Million British thermal units |
| MMCFD | Million cubic feet per day |
| NGL(s) | Natural Gas Liquid(s), primarily ethane, propane, normal butane, isobutane and natural gasoline |
| Percentage of Proceeds (POP) | A contract with a natural gas producer whereby the plant operator retains a negotiated percentage of the sale proceeds. |
| Residue gas | The portion of natural gas remaining after natural gas is processed for removal of NGLs and impurities. |

Table of Contents**PART I. FINANCIAL INFORMATION****ITEM 1. FINANCIAL STATEMENTS****ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED BALANCE SHEETS**

(in thousands)

(Unaudited)

| | June 30, 2014 | December 31, 2013 |
|--|--------------------------|------------------------------|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | \$ 4,074 | \$ 4,914 |
| Accounts receivable | 254,953 | 219,297 |
| Current portion of derivative assets | | 174 |
| Prepaid expenses and other | 26,549 | 17,393 |
| Total current assets | 285,576 | 241,778 |
| Property, plant and equipment, net | 2,984,168 | 2,724,192 |
| Goodwill | 365,763 | 368,572 |
| Intangible assets, net | 634,086 | 696,271 |
| Equity method investment in joint ventures | 179,054 | 248,301 |
| Long-term portion of derivative assets | 451 | 2,270 |
| Other assets, net | 43,931 | 46,461 |
| Total assets | \$ 4,493,029 | \$ 4,327,845 |
| LIABILITIES AND EQUITY | | |
| Current liabilities: | | |
| Current portion of long-term debt | \$ 320 | \$ 524 |
| Accounts payable affiliates | 4,302 | 2,912 |
| Accounts payable | 124,074 | 79,051 |
| Accrued liabilities | 52,810 | 47,449 |
| Accrued interest payable | 26,746 | 26,737 |
| Current portion of derivative liabilities | 11,454 | 11,244 |
| Accrued producer liabilities | 179,843 | 152,309 |
| Total current liabilities | 399,549 | 320,226 |
| Long-term portion of derivative liabilities | 216 | 320 |
| Long-term debt, less current portion | 1,654,319 | 1,706,786 |
| Deferred income taxes, net | 32,394 | 33,290 |
| Other long-term liabilities | 7,011 | 7,318 |

Commitments and contingencies**Equity:**

| | | |
|---|--------------|--------------|
| Class D convertible preferred limited partners' interests | 493,630 | 450,749 |
| Class E preferred limited partners' interests | 121,852 | |
| Common limited partners' interests | 1,666,438 | 1,703,778 |
| General Partner's interest | 45,840 | 46,118 |
| Total partners' capital | 2,327,760 | 2,200,645 |
| Non-controlling interest | 71,780 | 59,260 |
| Total equity | 2,399,540 | 2,259,905 |
| Total liabilities and equity | \$ 4,493,029 | \$ 4,327,845 |

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|--------------------------------|-------------------|------------------------------|--------------------|
| | 2014 | 2013 | 2014 | 2013 |
| Revenue: | | | | |
| Natural gas and liquids sales | \$ 667,549 | \$ 491,230 | \$ 1,330,679 | \$ 875,078 |
| Transportation, processing and other fees third parties | 49,952 | 40,229 | 93,334 | 72,883 |
| Transportation, processing and other fees affiliates | 91 | 77 | 146 | 148 |
| Derivative gain (loss), net | (6,367) | 27,107 | (15,038) | 15,024 |
| Other income, net | 2,731 | 2,296 | 4,839 | 5,718 |
| Total revenues | 713,956 | 560,939 | 1,413,960 | 968,851 |
| Costs and expenses: | | | | |
| Natural gas and liquids cost of sales | 580,885 | 424,216 | 1,156,353 | 749,756 |
| Operating expenses | 26,983 | 24,770 | 52,111 | 46,629 |
| General and administrative | 17,166 | 11,296 | 33,856 | 23,844 |
| Compensation reimbursement affiliates | 1,250 | 1,250 | 2,500 | 2,500 |
| Other (revenues) costs | (20) | 18,370 | 17 | 18,900 |
| Depreciation and amortization | 49,220 | 46,383 | 98,459 | 76,841 |
| Interest | 23,059 | 22,581 | 46,722 | 41,267 |
| Total costs and expenses | 698,543 | 548,866 | 1,390,018 | 959,737 |
| Equity income (loss) in joint ventures | (3,875) | (472) | (5,753) | 1,568 |
| Gain (loss) on asset dispositions | 48,465 | (1,519) | 48,465 | (1,519) |
| Loss on early extinguishment of debt | | (19) | | (26,601) |
| Income (loss) before tax | 60,003 | 10,063 | 66,654 | (17,438) |
| Income tax benefit | (498) | (28) | (896) | (37) |
| Net income (loss) | 60,501 | 10,091 | 67,550 | (17,401) |
| Income attributable to non-controlling interests | (3,965) | (1,810) | (6,427) | (3,179) |
| Preferred unit imputed dividend effect | (11,378) | (6,729) | (22,756) | (6,729) |
| Preferred unit dividends in kind | (10,406) | (5,341) | (20,125) | (5,341) |
| Preferred unit dividends | (2,609) | | (3,015) | |
| Net income (loss) attributable to common limited partners and the General Partner | \$ 32,143 | \$ (3,789) | \$ 15,227 | \$ (32,650) |

Allocation of net income (loss) attributable to:

| | | | | |
|---------------------------------|-----------|------------|-----------|-------------|
| Common limited partner interest | \$ 25,740 | \$ (8,408) | \$ 4,296 | \$ (39,614) |
| General Partner interest | 6,403 | 4,619 | 10,931 | 6,964 |
| | \$ 32,143 | \$ (3,789) | \$ 15,227 | \$ (32,650) |

Net income (loss) attributable to common limited partners per unit:

| | | | | |
|---|---------|-----------|---------|-----------|
| Basic | \$ 0.27 | \$ (0.11) | \$ 0.04 | \$ (0.57) |
| Weighted average common limited partner units (basic) | 80,979 | 74,340 | 80,788 | 69,520 |
| Diluted | \$ 0.27 | \$ (0.11) | \$ 0.04 | \$ (0.57) |
| Weighted average common limited partner units (diluted) | 96,890 | 74,340 | 96,498 | 69,520 |

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands, except unit data)

(Unaudited)

| | Class D Preferred Limited Partner Units | Class E Preferred Limited Partner Units | Common Limited Partner Units | Class D Preferred Limited Partners | Class E Preferred Limited Partners | Common Limited Partners | General Partner | Non- controlling Interest | Total |
|--|---|---|---------------------------------------|---|---|-------------------------------|--------------------|---------------------------------|--------------|
| Balance at December 31, 2013 | 13,823,869 | | 80,585,148 | \$ 450,749 | \$ | \$ 1,703,778 | \$ 46,118 | \$ 59,260 | \$ 2,259,905 |
| Issuance of units and General Partner capital contribution | | 5,060,000 | 1,462,187 | | 122,258 | 47,421 | 985 | | 170,664 |
| Issuance of common units under incentive plans | | | 115,632 | | | 91 | | | 91 |
| Units issued common units under incentive plans | | | | | | 12,731 | | | 12,731 |
| Distributions paid in kind units | 580,768 | | | | | | | | |
| Distributions paid | | | | | | (101,879) | (12,194) | | (114,073) |
| Distributions payable | | | | | (3,421) | | | | (3,421) |
| Contributions from non-controlling interests | | | | | | | | 7,880 | 7,880 |
| Distributions to non-controlling interests | | | | | | | | (1,787) | (1,787) |
| Net income | | | | 42,881 | 3,015 | 4,296 | 10,931 | 6,427 | 67,550 |
| | 14,404,637 | 5,060,000 | 82,162,967 | \$ 493,630 | \$ 121,852 | \$ 1,666,438 | \$ 45,840 | \$ 71,780 | \$ 2,399,540 |

See accompanying notes to consolidated financial statements

Table of Contents**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(in thousands)****(Unaudited)**

| | Six Months Ended June 30, | |
|--|--------------------------------------|----------------|
| | 2014 | 2013 |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net income (loss) | \$ 67,550 | \$ (17,401) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation and amortization | 98,459 | 76,841 |
| Equity (income) loss in joint ventures | 5,753 | (1,568) |
| Distributions received from equity method joint ventures | 4,200 | 3,600 |
| Non-cash compensation expense | 12,882 | 7,820 |
| Amortization of deferred finance costs | 3,730 | 3,283 |
| Loss on early extinguishment of debt | | 26,601 |
| Loss (gain) on asset dispositions | (48,465) | 1,519 |
| Income tax benefit | (896) | (37) |
| Change in operating assets and liabilities: | | |
| Accounts receivable, prepaid expenses and other | (44,604) | (57,274) |
| Accounts payable and accrued liabilities | 37,811 | 38,982 |
| Accounts payable and accounts receivable affiliates | 1,390 | (1,933) |
| Derivative accounts payable and receivable | 2,099 | (8,712) |
| Net cash provided by operating activities | 139,909 | 71,721 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Capital expenditures | (280,579) | (215,709) |
| Cash paid for business combinations, net of cash received | | (1,000,785) |
| Net proceeds from asset disposition | 132,666 | |
| Capital contributions to joint ventures | (1,649) | |
| Other | (850) | 250 |
| Net cash used in investing activities | \$ (150,412) | \$ (1,216,244) |

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS CONTINUED

(in thousands)

(Unaudited)

| | Six Months Ended | |
|--|-------------------------|-------------|
| | June 30, | |
| | 2014 | 2013 |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Borrowings under credit facility | \$ 503,500 | \$ 865,000 |
| Repayments under credit facility | (555,500) | (1,078,000) |
| Net proceeds from issuance of long term debt | | 1,028,449 |
| Repayment of long-term debt | | (365,822) |
| Payment of premium on retirement of debt | | (25,581) |
| Payment of deferred financing costs | (350) | (893) |
| Payment for acquisition-based contingent consideration | | (6,000) |
| Principal payments on capital lease | (333) | (10,578) |
| Net proceeds from issuance of common and preferred limited partner units | 169,679 | 825,235 |
| General Partner capital contributions | 985 | 17,280 |
| Contributions from non-controlling interest holders | 7,880 | 5,176 |
| Distributions to non-controlling interest holders | (1,787) | (500) |
| Distributions paid to common limited partners and the General Partner | (114,073) | (91,115) |
| Other | (338) | (445) |
| Net cash provided by financing activities | 9,663 | 1,162,206 |
| Net change in cash and cash equivalents | (840) | 17,683 |
| Cash and cash equivalents, beginning of period | 4,914 | 3,398 |
| Cash and cash equivalents, end of period | \$ 4,074 | \$ 21,081 |

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2014

(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States and natural gas gathering services in the Appalachian Basin in the northeastern region of the United States. 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 majority-owned subsidiary of the Partnership. At June 30, 2014, Atlas Pipeline Partners GP, LLC (the General Partner) owned a combined 2.0% general partner interest in the consolidated operations of the Partnership, through which it manages and effectively controls both the Partnership and the Operating Partnership. The General Partner is a wholly-owned subsidiary of Atlas Energy, L.P. (ATLS), a publicly-traded limited partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations of the Partnership consists of limited partner interests. At June 30, 2014, the Partnership had 82,162,967 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS; 14,404,637 Class D convertible preferred units (Class D Preferred Units) outstanding (see Note 5); and 5,060,000 8.25% Class E cumulative redeemable perpetual preferred units (Class E Preferred Units) outstanding (see Note 5).

The accompanying consolidated financial statements, which are unaudited, except the balance sheet dated December 31, 2013, which is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States for interim reporting. The accompanying consolidated financial statements and notes thereto do not include all disclosures normally made in financial statements contained in Form 10-K. In management's opinion, all adjustments necessary for a fair presentation of the Partnership's financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2013. Certain amounts in the prior year's consolidated financial statements have been reclassified to conform to the current year presentation. The results of operations for the six month period ended June 30, 2014 may not necessarily be indicative of the results of operations for the full year ending December 31, 2014.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership's significant accounting policies is included in its audited consolidated financial statements and notes thereto in its Annual Report on Form 10-K for the year ended December 31, 2013.

Principles of Consolidation and Non-Controlling Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership, a variable interest entity of which the Partnership is the primary beneficiary, 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 2.0% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

Table of Contents*Comprehensive Income (Loss)*

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as other comprehensive income (loss). The Partnership does not have any type of transaction, which would be included within other comprehensive income (loss), thus comprehensive income (loss) is equal to net income (loss).

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 by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner's and the preferred unitholders' interests. The General Partner's interest in net income (loss) is calculated on a quarterly basis based upon its 2.0% general partner interest and incentive distributions to be distributed for the quarter (see Note 5), with a priority allocation of net income to the General Partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner's and limited partners' ownership interests.

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

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

Class D Preferred Units participate in distributions with the common limited partner units according to a predetermined formula (see Note 5), thus they are considered participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution.

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However, the contractual terms of the Class D Preferred Units do not require the holders to share in the losses of the entity, therefore the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the Class D Preferred Units on a pro-rata basis.

Class E Preferred Units do not participate in distributions with the common limited partner units according to a predetermined formula, but rather receive distributions based upon a set percentage rate (see Note 5), thus they are not considered participating securities. However, income available to common limited partners is reduced by the distributions accumulated for the period on the Class E Preferred Units, whether declared or not since the distributions on Class E Preferred Units are cumulative.

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) attributable to common limited partners per unit (in thousands):

| | Three Months | | Six Months Ended | |
|--|---------------------|-------------|-------------------------|-------------|
| | Ended | | June 30, | |
| | 2014 | 2013 | 2014 | 2013 |
| Net income (loss) | \$ 60,501 | \$ 10,091 | \$ 67,550 | \$ (17,401) |
| Income attributable to non-controlling interests | (3,965) | (1,810) | (6,427) | (3,179) |
| Preferred unit imputed dividend effect | (11,378) | (6,729) | (22,756) | (6,729) |
| Preferred unit dividends in kind | (10,406) | (5,341) | (20,125) | (5,341) |
| Preferred unit dividends | (2,609) | | (3,015) | |
| Net income (loss) attributable to common limited partners and the General Partner | 32,143 | (3,789) | 15,227 | (32,650) |
| General Partner's cash incentive distributions | 5,875 | 4,790 | 10,843 | 7,776 |
| General Partner's ownership interest | 528 | (171) | 88 | (812) |
| Net income attributable to the General Partner's ownership interests | 6,403 | 4,619 | 10,931 | 6,964 |
| Net income (loss) attributable to common limited partners | 25,740 | (8,408) | 4,296 | (39,614) |
| Net income attributable to participating securities - phantom unit ⁽¹⁾ | 440 | | 71 | |
| Net income attributable to participating securities - Class D Preferred Units ⁽²⁾ | 3,826 | | 635 | |
| Net income attributable to participating securities | 4,266 | | 706 | |
| Net income (loss) utilized in the calculation of net loss attributable to common limited partners per unit | \$ 21,474 | \$ (8,408) | \$ 3,590 | \$ (39,614) |

(1) Net loss attributable to common limited partners' ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three and six months ended June 30, 2013, net loss

attributable to common limited partners' ownership interest is not allocated to approximately 967,000 and 1,011,000 weighted average phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

- (2) Net loss attributable to common limited partners' ownership interest is allocated to the Class D Preferred Units on a pro-rata basis (weighted average Class D Preferred Units outstanding, plus a contractual yield premium of 1%, as a percentage of the sum of the weighted average Class D Preferred Units and common limited partner units outstanding). For the three and six months ended June 30, 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 9,013,000 and 4,531,000 weighted average Class D Preferred Units, respectively, because the contractual terms of the Class D Preferred Units as participating securities do not require the holders to share in the losses of the entity.

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Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities and the effects of outstanding convertible securities. The phantom units and Class D Preferred Units are participating securities included in the calculation of diluted net income (loss) attributable to common units, due to their participation rights and due to their dilution if converted. The Class E Preferred Units are not participating securities and are not convertible and thus are not included in the units outstanding for calculation of diluted net income (loss) attributable to common limited partners per unit.

The following table sets forth the reconciliation of the Partnership's 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):

| | Three Months Ended | | Six Months Ended | |
|--|--------------------|--------|------------------|--------|
| | June 30, | | June 30, | |
| | 2014 | 2013 | 2014 | 2013 |
| Weighted average number of common limited partner units basic | 80,979 | 74,340 | 80,788 | 69,520 |
| Add effect of dilutive securities – phantom units ⁽¹⁾ | 1,654 | | 1,599 | |
| Add effect of convertible preferred limited partner units ⁽²⁾ | 14,257 | | 14,111 | |
| Weighted average common limited partner units – diluted | 96,890 | 74,340 | 96,498 | 69,520 |

- (1) For the three and six months ended June 30, 2013, approximately 967,000 and 1,011,000 weighted average phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.
- (2) For the three and six months ended June 30, 2013, approximately 9,013,000 and 4,531,000 weighted average Class D Preferred Units, respectively, 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.

Revenue Recognition

The Partnership accrues unbilled revenue and the related purchase costs 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 gathering and compression fees and applicable product prices. The Partnership had unbilled revenues at June 30, 2014 and December 31, 2013 of \$179.5 million and \$134.9 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Cash and 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. Checks outstanding at the end of a period that exceed available cash balances

held at the bank are considered to be book overdrafts and are reclassified to accounts payable. At June 30, 2014 and December 31, 2013, the Partnership reclassified the balances related to book overdrafts of \$23.0 million and \$28.8 million, respectively, from cash and cash equivalents to accounts payable on the Partnership's consolidated balance sheets.

Table of Contents*Recently Adopted Accounting Standards*

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

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). ASU 2014-09 will supersede the revenue recognition requirements in Topic 605 Revenue Recognition, and most industry-specific guidance. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.

The amendments in ASU 2014-09 are effective for interim and annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. An entity should apply the amendments in this ASU using one of the following methods: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect of initially applying the standard recognized at the date of initial application.

The Partnership will apply these requirements upon the adoption of ASU 2014-09 on January 1, 2017. The Partnership is currently in the process of evaluating which method to use for application of ASU 2014-09 and is still determining the impacts of ASU 2014-09 on its financial position, results of operations and disclosures.

NOTE 3 ACQUISITIONS

On May 7, 2013, the Partnership completed the acquisition of 100% of the equity interests of TEAK Midstream, LLC (TEAK) for \$974.7 million in cash, including final purchase price adjustments, less cash received (the TEAK Acquisition). The assets of these companies include gas gathering and processing facilities in Texas. The acquisition included a 75% interest in T2 LaSalle Gathering Company L.L.C. (T2 LaSalle); a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (T2 Eagle Ford); and a 50% interest in T2 EF Cogeneration Holdings L.L.C. (T2 Co-Gen and together with T2 Eagle Ford and T2 LaSalle, the T2 Joint Ventures).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their acquisition date fair values. The following table presents the values assigned to the assets acquired and liabilities assumed in the TEAK Acquisition, based on their final estimated fair values at the date of the acquisition (in thousands):

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| | |
|--|-------------------|
| Cash | \$ 8,074 |
| Accounts receivable | 11,055 |
| Prepaid expenses and other | 1,626 |
| Property, plant and equipment | 197,683 |
| Intangible assets | 430,000 |
| Goodwill | 186,050 |
| Equity method investment in joint ventures | 184,327 |
| | |
| Total assets acquired | 1,018,815 |
| | |
| Accounts payable and accrued liabilities | (34,995) |
| Other long term liabilities | (1,075) |
| | |
| Total liabilities acquired | (36,070) |
| | |
| Net assets acquired | 982,745 |
| Less cash received | (8,074) |
| | |
| Net cash paid for acquisition | \$ 974,671 |

NOTE 4 EQUITY METHOD INVESTMENTS*West Texas LPG Pipeline Limited Partnership*

On May 14, 2014, the Partnership completed the sale of two indirect subsidiaries, which held an aggregate 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), to a subsidiary of Martin Midstream Partners L.P. (NYSE: MMLP). The Partnership received \$132.7 million in proceeds, net of selling costs, which were used to pay down the Partnership's revolving credit facility (see Note 13). As a result of the sale, the Partnership recorded a \$48.5 million gain on asset dispositions on its consolidated statements of operations for the three and six months ended June 30, 2014.

WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (NYSE: CVX), which owns the remaining 80% interest. The Partnership accounted for its subsidiaries' ownership interest in WTLPG under the equity method of accounting, with recognition of income of WTLPG as equity income in joint ventures on its consolidated statements of operations.

T2 Joint Ventures

On May 7, 2013, the Partnership acquired a 75% interest in T2 LaSalle, a 50% interest in T2 Eagle Ford and a 50% interest in T2 EF Co-Gen as part of the TEAK Acquisition (see Note 3). The T2 Joint Ventures are operated by TexStar Midstream Services, L.P. (TexStar), the investor owning the remaining interests. The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The Partnership accounts for its investments in the joint ventures under the equity method of accounting.

The Partnership evaluated whether the T2 Joint Ventures should be subject to consolidation. The T2 Joint Ventures do meet the qualifications of a Variable Interest Entity (VIE), but the Partnership does not meet the qualifications as the

primary beneficiary. Even though the Partnership owns a 50% or

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greater interest in the T2 Joint Ventures, the Partnership does not have controlling financial interests in these entities. Since the Partnership shares equal management rights with TexStar, and TexStar is the operator of the T2 Joint Ventures, the Partnership determined that it is not the primary beneficiary of the VIEs and should not consolidate the T2 Joint Ventures. The Partnership accounts for its investment in the T2 Joint Ventures under the equity method, since the Partnership does not have a controlling financial interest, but does have a significant influence. The Partnership's maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment, any additional capital contribution commitments and the Partnership's share of any approved operating expenses incurred by the VIEs.

The following table presents the value of the Partnership's equity method investments in joint ventures as of June 30, 2014 and December 31, 2013 (in thousands):

| | June 30, 2014 | December 31, 2013 |
|--|--------------------------|------------------------------|
| WTLPG | \$ | \$ 85,790 |
| T2 LaSalle | 57,578 | 50,534 |
| T2 Eagle Ford | 107,314 | 97,437 |
| T2 EF Co-Gen | 14,162 | 14,540 |
| Equity method investment in joint ventures | \$ 179,054 | \$ 248,301 |

The following table presents the Partnership's equity income (loss) in joint ventures for the three and six months ended June 30, 2014 and 2013 (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--|--|-------------|--------------------------------------|-------------|
| | 2014 | 2013 | 2014 | 2013 |
| WTLPG | \$ 884 | \$ 1,687 | \$ 2,611 | \$ 3,727 |
| T2 LaSalle | (1,364) | (898) | (2,477) | (898) |
| T2 Eagle Ford | (2,693) | (1,078) | (4,738) | (1,078) |
| T2 EF Co-Gen | (702) | (183) | (1,149) | (183) |
| Equity income (loss) in joint ventures | \$ (3,875) | \$ (472) | \$ (5,753) | \$ 1,568 |

NOTE 5 EQUITY***Common Units***

On May 12, 2014, the Partnership entered into an Equity Distribution Agreement (the "2014 EDA") with Citigroup Global Markets Inc. ("Citigroup"), Wells Fargo Securities, LLC and MLV & Co. LLC (together, the "Sales Agents"). Pursuant to the 2014 EDA, the Partnership may offer and sell from time to time through its Sales Agents, common units having an aggregate value up to \$250.0 million. Sales are at market prices prevailing at the time of the sale.

In November 2012, the Partnership entered into an Equity Distribution Agreement (the 2012 EDA , and together with the 2014 EDA, the EDAs) with Citigroup. Pursuant to this program, the Partnership offered and sold through Citigroup, as its sales agent, common units for \$150.0 million. The Partnership used the full capacity under the 2012 EDA during the year ended 2013.

During the three months ended June 30, 2014 and 2013, the Partnership issued 1,462,187 and 642,495 common units, respectively, under the EDAs for net proceeds of \$47.4 million and \$24.5 million,

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respectively, net of \$0.5 million and \$0.5 million, respectively, in commissions paid to the Sales Agents. During the six months ended June 30, 2014 and 2013, the Partnership issued 1,462,187 and 1,090,280 common units, respectively, under the EDAs for net proceeds of \$47.4 million and \$38.9 million, respectively, net of \$0.5 million and \$0.8 million, respectively, in commissions paid to the Sales Agents. The Partnership also received capital contributions from the General Partner of \$1.0 million and \$0.5 million, respectively, during the three months ended June 30, 2014 and 2013, and \$1.0 million and \$0.8 million, respectively, during the six months ended June 30, 2014 and 2013, to maintain its 2.0% general partner interest in the Partnership. The net proceeds from the common unit offerings were utilized for general partnership purposes.

Cash Distributions

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders (subject to the rights of any other class or series of the Partnership's securities with the right to share in the Partnership's cash distributions) and to 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, including the General Partner's 2.0% interest. The General Partner, which holds all the incentive distribution rights in the Partnership, has agreed to allocate up to \$3.75 million of its incentive distribution rights per quarter back to the Partnership after the General Partner receives the initial \$7.0 million per quarter of incentive distribution rights.

Common unit and General Partner distributions declared by the Partnership for quarters ending from March 31, 2013 through March 31, 2014 were as follows:

| For Quarter Ended | Date Cash Distribution Paid | 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) |
|--------------------------|------------------------------------|--|--|--|
| March 31, 2013 | May 15, 2013 | \$ 0.59 | \$ 45,382 | \$ 3,980 |
| June 30, 2013 | August 14, 2013 | 0.62 | 48,165 | 5,875 |
| September 30, 2013 | November 14, 2013 | 0.62 | 49,298 | 6,013 |
| December 31, 2013 | February 14, 2014 | 0.62 | 49,969 | 6,095 |
| March 31, 2014 | May 15, 2014 | 0.62 | 49,998 | 6,099 |

On July 23, 2014, the Partnership declared a cash distribution of \$0.63 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2014. The \$58.8 million distribution, including \$7.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2014 to unitholders of record at the close of business on August 7, 2014.

Class D Preferred Units

The Partnership's Class D Preferred Units are presented combined with a net \$38.8 million unaccreted beneficial conversion discount on the Partnership's consolidated balance sheets as of June 30, 2014. The Partnership recorded \$11.4 million and \$6.7 million for the three months ended June 30, 2014 and 2013, respectively, and \$22.8 million and \$6.7 million for the six months ended June 30, 2014 and 2013, respectively, within preferred unit imputed

dividend effect on the Partnership's consolidated statements of operations to recognize the accretion of the beneficial conversion discount.

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The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance in May 2013, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of the General Partner. The Partnership recorded Class D Preferred Unit distributions in kind of \$10.4 million and \$5.3 million for the three months ended June 30, 2014 and 2013, respectively, and \$20.1 million and \$5.3 million for the six months ended June 30, 2014 and 2013, respectively, as preferred unit dividends in kind on the Partnership's consolidated statements of operations. During the three and six months ended June 30, 2014, the Partnership distributed 305,983 and 580,768, respectively, Class D Preferred Units to the holders of the Class D Preferred Units. The Partnership did not distribute any Class D Preferred Units during the three and six months ended June 30, 2013. The Partnership considers preferred unit distributions paid in kind to be a non-cash financing activity.

On July 23, 2014, the Partnership declared a cash distribution of \$0.63 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2014. Based on this declaration, on August 14, 2014, the Partnership will issue approximately 305,000 Class D Preferred Units as a preferred unit distribution in kind for the quarter ended June 30, 2014 to the preferred unitholders of record at the close of business on August 7, 2014.

Class E Preferred Units

On March 17, 2014, the Partnership issued 5,060,000 of its Class E Preferred Units to the public at an offering price of \$25.00 per Class E Preferred Unit. The Partnership received \$122.3 million in net proceeds. The proceeds were used to pay down the Partnership's revolving credit facility.

The Partnership will make cumulative cash distributions on the Class E Preferred Units from the date of original issue. The cash distributions will be payable quarterly in arrears on January 15, April 15, July 15, and October 15 of each year, when, and if, declared by the board of directors. The initial distribution on the Class E Preferred Units was paid on July 15, 2014 in an amount equal to \$0.67604 per unit, or approximately \$3.4 million, representing the distribution for the period March 17, 2014 to July 14, 2014. Going forward, the Partnership will pay cumulative distributions in cash on the Class E Preferred Units on a quarterly basis at a rate of \$0.515625 per unit, or 8.25% per year. For the three and six months ended June 30, 2014, the Partnership allocated net income of \$2.6 million and \$3.0 million, respectively, to the Class E Preferred Units for the dividends earned during the period, which was recorded as preferred unit dividends on its consolidated statements of operations.

At any time on or after March 17, 2019, or in the event of a liquidation or certain changes of control, the Partnership may redeem the Class E Preferred Units, in whole or in part, at a redemption price of \$25.00 per unit plus an amount equal to all accumulated and unpaid distributions on the date of redemption, whether or not declared. If the Partnership does not exercise this redemption right upon a change of control, then the holders of the Class E Preferred Units will have the option to convert their Class E Preferred Units into a number of the Partnership's common units, as set forth in the Certificate of Designation relating to the Class E Preferred Units.

Table of Contents**NOTE 6 PROPERTY, PLANT AND EQUIPMENT**

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 13) (in thousands):

| | June 30, 2014 | December 31, 2013 | Estimated Useful Lives in Years |
|--|--------------------------|------------------------------|--|
| Pipelines, processing and compression facilities | \$ 3,202,816 | \$ 2,885,303 | 2 40 |
| Rights of way | 201,860 | 203,136 | 20 40 |
| Buildings | 10,447 | 10,291 | 40 |
| Furniture and equipment | 13,811 | 13,800 | 3 7 |
| Other | 15,165 | 15,805 | 3 10 |
| | 3,444,099 | 3,128,335 | |
| Less accumulated depreciation | (459,931) | (404,143) | |
| | \$ 2,984,168 | \$ 2,724,192 | |

The Partnership recorded depreciation expense on property, plant and equipment, including capital lease arrangements (see Note 13), of \$28.5 million and \$24.2 million for the three months ended June 30, 2014 and 2013, respectively, and \$56.3 million and \$46.5 million for the six months ended June 30, 2014 and 2013, respectively, on its consolidated statements of operations.

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds was 5.6% and 5.8% for the three months ended June 30, 2014 and 2013, respectively, and 5.6% and 6.0% for the six months ended June 30, 2014 and 2013, respectively. The amount of interest capitalized was \$3.2 million and \$1.3 million for the three months ended June 30, 2014 and 2013, respectively, and \$6.1 million and \$3.8 million for the six months ended June 30, 2014 and 2013, respectively.

NOTE 7 GOODWILL AND INTANGIBLE ASSETS

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. Impairment testing for goodwill is done at the reporting unit level. A reporting unit is an operating segment or one level below an operating segment (also known as a component). The Partnership evaluates goodwill for impairment annually, on December 31, for all reporting units, except SouthTX, which is evaluated on April 30. The Partnership tested the SouthTX reporting unit goodwill for impairment as of April 30, 2014. The results indicated the fair value of the SouthTX reporting unit was higher than its carrying value, and thus, goodwill recorded on the SouthTX reporting unit was not impaired as of April 30, 2014. The following table reflects the carrying amounts of goodwill by reporting unit at June 30, 2014 and December 31, 2013 (in thousands):

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| | June 30, 2014 | December 31, 2013 |
|---|--------------------------|------------------------------|
| Carrying amount of goodwill by reporting unit: | | |
| Barnett system | \$ 951 | \$ 951 |
| SouthOK system | 170,381 | 170,381 |
| SouthTX system | 186,050 | 188,859 |
| WestOK system | 8,381 | 8,381 |
| | \$ 365,763 | \$ 368,572 |

The change in goodwill is related to a \$2.8 million decrease in goodwill related to an adjustment of the fair value of assets acquired and liabilities assumed from the TEAK Acquisition (See Note 3). The Partnership expects all goodwill recorded to be deductible for tax purposes.

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at June 30, 2014 and December 31, 2013 (in thousands):

| | June 30, 2014 | December 31, 2013 | Estimated Useful Lives In Years |
|----------------------------------|--------------------------|------------------------------|--|
| Gross carrying amount: | | | |
| Customer contracts | \$ 3,419 | \$ 3,419 | 2 10 |
| Customer relationships | 867,653 | 887,653 | 7 15 |
| | 871,072 | 891,072 | |
| Accumulated amortization: | | | |
| Customer contracts | (1,030) | (779) | |
| Customer relationships | (235,956) | (194,022) | |
| | (236,986) | (194,801) | |
| Net carrying amount: | | | |
| Customer contracts | 2,389 | 2,640 | |
| Customer relationships | 631,697 | 693,631 | |
| Net carrying amount | \$ 634,086 | \$ 696,271 | |

The weighted-average amortization period for customer contracts and customer relationships, as of June 30, 2014, is 9.7 years and 11.5 years, respectively. The Partnership recorded amortization expense on intangible assets of \$20.7 million and \$22.2 million for the three months ended June 30, 2014 and 2013, respectively, and \$42.2 million and \$30.3 million for the six months ended June 30, 2014 and 2013, respectively, on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: remainder of 2014 \$37.8 million; 2015 through 2016 \$74.0 million per year; 2017 \$68.0 million per year; 2018 \$59.5 million.

Table of Contents**NOTE 8 OTHER ASSETS**

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

| | June 30, 2014 | December 31, 2013 |
|--|--------------------------|------------------------------|
| Deferred finance costs, net of accumulated amortization of \$25,764 and \$22,034 at June 30, 2014 and December 31 2013, respectively | \$ 37,714 | \$ 41,094 |
| Security deposits | 6,217 | 5,367 |
| | \$ 43,931 | \$ 46,461 |

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). The Partnership incurred \$0.1 million and \$9.4 million of deferred finance costs during the three months ended June 30, 2014 and 2013, respectively, and \$0.3 million and \$22.4 million deferred finance costs during the six months ended June 30, 2014 and 2013, respectively, related to various financing activities (see Note 13).

During the six months ended June 30, 2013, the Partnership redeemed all of its outstanding \$365.8 million 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes) (see Note 13) and recognized \$5.3 million of accelerated amortization of deferred financing costs, included in loss on early extinguishment of debt on the Partnership's consolidated statement of operations. There was no accelerated amortization of deferred financing costs during the six months ended June 30, 2014. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was \$1.9 million and \$1.7 million for the three months ended June 30, 2014 and 2013, respectively, and \$3.7 million and \$3.3 million for the six months ended June 30, 2014 and 2013, respectively, which is recorded within interest expense on the Partnership's consolidated statements of operations.

NOTE 9 INCOME TAXES

The Partnership owns APL Arkoma, Inc., a taxable subsidiary. The components of the federal and state income tax benefit of the Partnership's taxable subsidiary for the three and six months ended June 30, 2014 and 2013 are summarized as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|--------------------------|--|-------------|--------------------------------------|-------------|
| | 2014 | 2013 | 2014 | 2013 |
| Income tax benefit: | | | | |
| Federal | \$ (446) | \$ (25) | \$ (803) | \$ (33) |
| State | (52) | (3) | (93) | (4) |
| Total income tax benefit | \$ (498) | \$ (28) | \$ (896) | \$ (37) |

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The components of net deferred tax liabilities as of June 30, 2014 and December 31, 2013 consist of the following (in thousands):

| | June 30, 2014 | December 31, 2013 |
|--|--------------------------|------------------------------|
| Deferred tax assets: | | |
| Net operating loss tax carryforwards and alternative minimum tax credits | \$ 16,198 | \$ 14,900 |
| Deferred tax liabilities: | | |
| Excess of asset carrying value over tax basis | (48,592) | (48,190) |
| Net deferred tax liabilities | \$ (32,394) | \$ (33,290) |

As of June 30, 2014, the Partnership had net operating loss carry forwards for federal income tax purposes of approximately \$41.9 million, which expire at various dates from 2029 to 2034. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 10 DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price risk management activities. The Partnership uses 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. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. Due to the right of setoff, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty.

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

Offsetting of Derivative Assets

| | Gross Amounts of Recognized Assets | Gross Amounts Offset in the Consolidated Balance Sheets | Net Amounts of Assets Presented in the Consolidated Balance Sheets |
|---|---|--|---|
| As of June 30, 2014: | | | |
| Long-term portion of derivative assets | \$ 1,365 | \$ (914) | \$ 451 |
| Current portion of derivative liabilities | 2,478 | (2,478) | |
| Long-term portion of derivative liabilities | 1,651 | (1,651) | |

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| | | | |
|---|----------|------------|----------|
| Total derivative assets, net | \$ 5,494 | \$ (5,043) | \$ 451 |
| <u>As of December 31, 2013:</u> | | | |
| Current portion of derivative assets | \$ 1,310 | \$ (1,136) | \$ 174 |
| Long-term portion of derivative assets | 5,082 | (2,812) | 2,270 |
| Current portion of derivative liabilities | 1,612 | (1,612) | |
| Long-term portion of derivative liabilities | 949 | (949) | |
| Total derivative assets, net | \$ 8,953 | \$ (6,509) | \$ 2,444 |

Table of Contents**Offsetting of Derivative Liabilities**

| | Gross Amounts of Recognized Liabilities | Gross Amounts Offset in the Consolidated Balance Sheets | Net Amounts of Liabilities Presented in the Consolidated Balance Sheets |
|---|--|--|--|
| <u>As of June 30, 2014:</u> | | | |
| Long-term portion of derivative assets | \$ (914) | \$ 914 | \$ |
| Current portion of derivative liabilities | (13,932) | 2,478 | (11,454) |
| Long-term portion of derivative liabilities | (1,867) | 1,651 | (216) |
| Total derivative liabilities, net | \$ (16,713) | \$ 5,043 | \$ (11,670) |
| <u>As of December 31, 2013:</u> | | | |
| Current portion of derivative assets | \$ (1,136) | \$ 1,136 | \$ |
| Long-term portion of derivative assets | (2,812) | 2,812 | |
| Current portion of derivative liabilities | (12,856) | 1,612 | (11,244) |
| Long-term portion of derivative liabilities | (1,269) | 949 | (320) |
| Total derivative liabilities, net | \$ (18,073) | \$ 6,509 | \$ (11,564) |

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The following table summarizes the Partnership's commodity derivatives as of June 30, 2014, (fair value and volumes in thousands):

| Production Period | Commodity | Volumes⁽¹⁾ | Average Fixed Price (\$/Volume) | Fair Value⁽²⁾ Asset/ (Liability) |
|--------------------------------|------------------|------------------------------|--|--|
| Sold fixed price swaps | | | | |
| 2014 | Natural gas | 10,400 | \$ 4.11 | \$ (3,611) |
| 2015 | Natural gas | 19,510 | 4.27 | 495 |
| 2016 | Natural gas | 8,100 | 4.28 | 48 |
| 2017 | Natural gas | 1,200 | 4.47 | (72) |
| 2014 | NGLs | 38,052 | 1.24 | (3,132) |
| 2015 | NGLs | 68,166 | 1.21 | (2,472) |
| 2016 | NGLs | 9,450 | 1.03 | (84) |
| 2014 | Crude oil | 159 | 92.09 | (1,828) |
| 2015 | Crude oil | 210 | 90.26 | (1,597) |
| 2016 | Crude oil | 30 | 90.00 | (73) |
| Total fixed price swaps | | | | (12,326) |
| Purchased put options | | | | |
| 2014 | Natural gas | 200 | 4.15 | 11 |
| 2014 | NGLs | 5,040 | 0.96 | 51 |
| 2015 | NGLs | 3,150 | 0.94 | 88 |
| 2014 | Crude oil | 207 | 90.85 | 120 |
| 2015 | Crude oil | 270 | 89.18 | 866 |
| Sold call options | | | | |
| 2014 | NGLs | 2,520 | 1.32 | (5) |
| 2015 | NGLs | 1,260 | 1.28 | (24) |
| Total options | | | | 1,107 |
| Total derivatives | | | | \$ (11,219) |

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.

(2) See Note 11 for discussion on fair value methodology.

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The following table summarizes the gross effect of all derivative instruments on the Partnership's consolidated statements of operations for the periods indicated (in thousands):

| | For the Three Months Ended | | For the Six Months Ended | |
|--|----------------------------|------------------|--------------------------|------------------|
| | June 30, 2014 | June 30, 2013 | June 30, 2014 | June 30, 2013 |
| Derivatives not designated as hedges | | | | |
| Gain (loss) recognized in derivative gain (loss), net: | | | | |
| Commodity contract realized ⁽¹⁾ | \$ (6,619) | \$ 2,844 | \$ (16,454) | \$ 4,480 |
| Commodity contract unrealized ⁽²⁾ | 252 | 24,263 | 1,416 | 10,544 |
| Derivative gain (loss), net | \$ (6,367) | \$ 27,107 | \$ (15,038) | \$ 15,024 |

- (1) Realized gain (loss) represents the gain or loss incurred when the derivative contract expires and/or is cash settled.
- (2) Unrealized gain represents the mark-to-market gain recognized on open derivative contracts, which have not yet settled.

NOTE 11 FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

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

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

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

Derivative Instruments

At June 30, 2014, the valuations for all the Partnership's derivative contracts are defined as Level 2 assets and liabilities within the same class of nature and risk, with the exception of the Partnership's NGL fixed price swaps and NGL options, which are defined as Level 3 assets and liabilities within the same class of nature and risk.

The Partnership's Level 2 commodity derivatives include natural gas and crude oil swaps and options, which are calculated based upon observable market data related to the change in price of the underlying commodity. These

swaps and options are calculated by utilizing the New York Mercantile Exchange (NYMEX) quoted prices for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

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Valuations for the Partnership's NGL options are based on forward price curves developed by financial institutions, and therefore are defined as Level 3. The NGL options are over-the-counter instruments that are not actively traded in an open market, thus the Partnership utilizes the valuations provided by the financial institutions that provide the NGL options for trade. The Partnership tests these valuations for reasonableness through the use of an internal valuation model.

Valuations for the Partnership's NGL fixed price swaps are based on forward price curves provided by a third party, which the Partnership considers to be Level 3 inputs. The prices are adjusted based upon the relationship between the prices for the product/locations quoted by the third party and the underlying product/locations utilized for the swap contracts, as determined by a regression model of the historical settlement prices for the different product/locations. The regression model is recalculated on a quarterly basis. This adjustment is an unobservable Level 3 input. The NGL fixed price swaps are over-the-counter instruments which are not actively traded in an open market. However, the prices for the underlying products and locations do have a direct correlation to the prices for the products and locations provided by the third party, which are based upon trading activity for the products and locations quoted. A change in the relationship between these prices would have a direct impact upon the unobservable adjustment utilized to calculate the fair value of the NGL fixed price swaps.

The following table represents the Partnership's derivative assets and liabilities recorded at fair value as of June 30, 2014 and December 31, 2013 (in thousands):

| | Level 1 | Level 2 | Level 3 | Total |
|--------------------------|---------|----------------|----------------|-----------------|
| June 30, 2014 | | | | |
| Assets | | | | |
| Commodity swaps | \$ | \$ 2,595 | \$ 1,763 | \$ 4,358 |
| Commodity options | | 997 | 139 | 1,136 |
| Total assets | | 3,592 | 1,902 | 5,494 |
| Liabilities | | | | |
| Commodity swaps | | (9,233) | (7,451) | (16,684) |
| Commodity options | | | (29) | (29) |
| Total liabilities | | (9,233) | (7,480) | (16,713) |
| Total derivatives | \$ | \$ (5,641) | \$ (5,578) | \$ (11,219) |
| December 31, 2013 | | | | |
| Assets | | | | |
| Commodity swaps | \$ | \$ 2,994 | \$ 1,412 | \$ 4,406 |
| Commodity options | | 4,337 | 210 | 4,547 |
| Total assets | | 7,331 | 1,622 | 8,953 |
| Liabilities | | | | |
| Commodity swaps | | (4,695) | (13,378) | (18,073) |

| | | | | |
|-------------------|----|----------|-------------|------------|
| Total liabilities | | (4,695) | (13,378) | (18,073) |
| Total derivatives | \$ | \$ 2,636 | \$ (11,756) | \$ (9,120) |

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The Partnership's Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership's Level 3 derivative instruments for the six months ended June 30, 2014 (in thousands):

| | | NGL Fixed Price Swaps | | NGL Put Options | | NGL Call Options | | Total Amount |
|--|-------------------|-----------------------|-------------|-----------------|--------|------------------|---------|--------------|
| | | Gallons | Amount | Gallons | Amount | Gallons | Amount | |
| Balance | December 31, 2013 | 130,158 | \$ (11,966) | 6,300 | \$ 210 | | \$ | \$ (11,756) |
| New contracts ⁽¹⁾ | | 31,626 | | 5,040 | 200 | 5,040 | (200) | |
| Cash settlements from unrealized gain (loss) ⁽²⁾⁽³⁾ | | (46,116) | 8,447 | (3,150) | 225 | (1,260) | (20) | 8,652 |
| Net change in unrealized gain (loss) ⁽²⁾ | | | (2,169) | | (271) | | 171 | (2,269) |
| Deferred option premium recognition ⁽³⁾ | | | | | (225) | | 20 | (205) |
| Balance | June 30, 2014 | 115,668 | \$ (5,688) | 8,190 | \$ 139 | 3,780 | \$ (29) | \$ (5,578) |

(1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.

(2) Included within derivative gain (loss), net on the Partnership's consolidated statements of operations.

(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

The following table provides a summary of the unobservable inputs used in the fair value measurement of the Partnership's NGL fixed price swaps at June 30, 2014 and December 31, 2013 (in thousands):

| | Gallons | Third Party Quotes ⁽¹⁾ | Adjustments ⁽²⁾ | Total Amount | |
|--------------------------------|---------------|-----------------------------------|----------------------------|--------------|------------|
| As of June 30, 2014 | | | | | |
| Propane swaps | 89,460 | \$ (5,008) | \$ | \$ (5,008) | |
| Isobutane swaps | 2,520 | (767) | 313 | (454) | |
| Normal butane swaps | 2,520 | 342 | 85 | 427 | |
| Natural gasoline swaps | 21,168 | 539 | (1,192) | (653) | |
| Total NGL swaps | June 30, 2014 | 115,668 | \$ (4,894) | \$ (794) | \$ (5,688) |
| As of December 31, 2013 | | | | | |
| Propane swaps | 100,296 | \$ (10,260) | \$ | \$ (10,260) | |
| Isobutane swaps | 6,300 | (2,342) | 955 | (1,387) | |
| Normal butane swaps | 7,560 | 40 | 322 | 362 | |
| Natural gasoline swaps | 16,002 | 132 | (813) | (681) | |

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| | | | | | | |
|-----------------|-------------------|---------|-------------|----|-----|-------------|
| Total NGL swaps | December 31, 2013 | 130,158 | \$ (12,430) | \$ | 464 | \$ (11,966) |
|-----------------|-------------------|---------|-------------|----|-----|-------------|

- (1) Based upon the difference between the quoted market price provided by the third party and the fixed price of the swap.
- (2) Product and location basis differentials calculated through the use of a regression model, which compares the difference between the settlement prices for the products and locations quoted by the third party and the settlement prices for the actual products and locations underlying the derivatives, using a three year historical period.

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The following table provides a summary of the regression coefficient utilized in the calculation of the unobservable inputs for the Level 3 fair value measurements for the NGL fixed price swaps for the periods indicated (in thousands):

| | Level 3 NGL Swap Fair Value Adjustments | Adjustment based upon Regression Coefficient | | |
|---|--|---|--------------|---------|
| | | Lower 95% | Upper 95% | Average |
| <u>As of June 30, 2014:</u> | | | | |
| Isobutane | \$ 313 | 1.1090 | 1.1194 | 1.1142 |
| Normal butane | 85 | 1.0292 | 1.0329 | 1.0311 |
| Natural gasoline | (1,192) | 0.9695 | 0.9726 | 0.9711 |
| Total Level 3 adjustments June 30, 2014 | \$ (794) | | | |
| <u>As of December 31, 2013:</u> | | | | |
| Isobutane | \$ 955 | 1.1184 | 1.1284 | 1.1234 |
| Normal butane | 322 | 1.0341 | 1.0386 | 1.0364 |
| Natural gasoline | (813) | 0.9727 | 0.9751 | 0.9739 |
| Total Level 3 adjustments December 31, 2013 | \$ 464 | | | |

NGL Linefill

The Partnership had \$23.4 million and \$14.5 million of NGL linefill at June 30, 2014 and December 31, 2013, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties, for which the counterparty will pay at a designated later period at a price determined by the then market price. The Partnership's NGL linefill held by some counterparties will be settled at various periods in the future and is defined as a Level 3 asset, which is valued using the same forward price curve utilized to value the Partnership's NGL fixed price swaps. The product/location adjustment based upon the multiple regression analysis, which was included in the value of the linefill, was a reduction of \$0.4 million and \$0.4 million as of June 30, 2014 and December 31, 2013, respectively. The Partnership's NGL linefill held by other counterparties is adjusted on a monthly basis according to the volumes delivered to the counterparties each period and is valued on a first in first out (FIFO) basis.

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The following table provides a summary of changes in fair value of the Partnership's NGL linefill for the six months ended June 30, 2014 (in thousands):

| | | Linefill Valued at Market | | Linefill Valued on FIFO | | Total NGL Linefill | |
|---|-------------------|---------------------------|----------|-------------------------|-----------|--------------------|-----------|
| | | Gallons | Amount | Gallons | Amount | Gallons | Amount |
| Balance | December 31, 2013 | 5,788 | \$ 4,738 | 11,538 | \$ 9,778 | 17,326 | \$ 14,516 |
| Deliveries into NGL linefill | | 1,050 | 1,013 | 42,604 | 31,549 | 43,654 | 32,562 |
| NGL linefill sales | | | | (34,557) | (23,725) | (34,557) | (23,725) |
| Net change in NGL linefill valuation ⁽¹⁾ | | | 94 | | | | 94 |
| Balance | June 30, 2014 | 6,838 | \$ 5,845 | 19,585 | \$ 17,602 | 26,423 | \$ 23,447 |

(1) Included within natural gas and liquids sales on the Partnership's consolidated statements of operations.

Contingent Consideration

In February 2012, the Partnership acquired a gas gathering system and related assets for an initial net purchase price of \$19.0 million. The Partnership agreed to pay up to an additional \$12.0 million in contingent payments, payable in two equal amounts, if certain volumes are achieved on the acquired gathering system within a specified time period. Sufficient volumes were achieved in December 2012 and the Partnership paid the first contingent payment of \$6.0 million in January 2013. As of June 30, 2014, the fair value of the remaining contingent payment resulted in a \$6.0 million long term liability, which was recorded within other long term liabilities on the Partnership's consolidated balance sheets. The range of the undiscounted amount the Partnership could pay related to the remaining contingent payment is between \$0.0 and \$6.0 million.

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 the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership's current assets and liabilities on its consolidated balance sheets, other than the derivatives, NGL linefill and contingent consideration discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1 values. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value and thus is categorized as a Level 1 value. The estimated fair value of the Partnership's Senior Notes (see Note 13) is based upon the market approach and calculated using the yield of the Senior Notes as provided by financial institutions and thus is categorized as a Level 3 value. The estimated fair values of the Partnership's total debt at June 30, 2014 and December 31, 2013, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were \$1,685.3 million and \$1,663.6 million, respectively, compared with the carrying amounts of \$1,654.6 million and \$1,707.3 million, respectively.

Acquisitions

On May 7, 2013, the Partnership completed the TEAK Acquisition (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. These inputs require significant judgments and estimates at the time of the valuation.

Table of Contents**NOTE 12 ACCRUED LIABILITIES**

The following is a summary of accrued liabilities (in thousands):

| | June 30, 2014 | December 31, 2013 |
|---|--------------------------|------------------------------|
| Accrued capital expenditures | \$ 12,217 | \$ 17,898 |
| Acquisition-related liabilities | 6,712 | 8,933 |
| Accrued ad valorem and production taxes | 13,619 | 3,551 |
| Other | 20,262 | 17,067 |
| | \$ 52,810 | \$ 47,449 |

NOTE 13 DEBT

Total debt consists of the following (in thousands):

| | June 30, 2014 | December 31, 2013 |
|------------------------------|--------------------------|------------------------------|
| Revolving credit facility | \$ 100,000 | \$ 152,000 |
| 6.625% Senior notes due 2020 | 504,219 | 504,556 |
| 5.875% Senior notes due 2023 | 650,000 | 650,000 |
| 4.750% Senior notes due 2021 | 400,000 | 400,000 |
| Capital lease obligations | 420 | 754 |
| Total debt | 1,654,639 | 1,707,310 |
| Less current maturities | (320) | (524) |
| Total long term debt | \$ 1,654,319 | \$ 1,706,786 |

Cash payments for interest related to debt, net of capitalized interest, were \$8.2 million and \$0.4 million for the three months ended June 30, 2014 and 2013, respectively, and \$43.0 million and \$22.5 million for the six months ended June 30, 2014 and 2013.

Revolving Credit Facility

At June 30, 2014, the Partnership had a \$600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. The weighted average interest rate for borrowings on the revolving credit facility, at June 30, 2014, was 3.2%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$3.1 million was outstanding at June 30, 2014. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At June 30, 2014, the Partnership had \$496.9 million of remaining committed capacity under its revolving credit facility.

The events that constitute an event of default for the revolving credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the General Partner.

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On March 11, 2014, the Partnership entered into an amendment to the credit agreement governing the revolving credit facility which, among other changes:

adjusted the duration of, and maximum ratios allowed during, the Acquisition Period, as defined in the credit agreement, for the Consolidated Funded Debt Ratio, as defined in the credit agreement; and

permitted the payment of cash distributions, if any, on the Class E Preferred Units so long as the Partnership has a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to \$50 million.

As of June 30, 2014, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At June 30, 2014, the Partnership had \$500.0 million principal outstanding of 6.625% unsecured senior notes due October 1, 2020 (6.625% Senior Notes), \$650.0 million principal outstanding of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes), and \$400.0 million of 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes and with the 6.625% Senior Notes and 5.875% Senior Notes, the Senior Notes). The 6.625% Senior Notes are presented combined with a net \$4.2 million unamortized premium as of June 30, 2014.

Indentures governing the Senior Notes 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 its assets. The Partnership is in compliance with these covenants as of June 30, 2014.

4.75% Senior Notes

On May 10, 2013, the Partnership issued \$400.0 million of the 4.75% Senior Notes in a private placement transaction. The 4.75% Senior Notes were issued at par. The Partnership received net proceeds of \$391.2 million after underwriting commissions and other transactions costs and utilized the proceeds to repay a portion of the outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition (see Note 3).

5.875% Senior Notes

On February 11, 2013, the Partnership issued \$650.0 million of the 5.875% Senior Notes in a private placement transaction. The 5.875% Senior Notes were issued at par. The Partnership received net proceeds of \$637.3 million after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the credit facility.

8.75% Senior Notes

On January 28, 2013, the Partnership commenced a cash tender offer for any and all of its outstanding 8.75% Senior Notes and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default contained in the indenture governing the 8.75% Senior

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Notes (8.75% Senior Notes Indenture). Approximately \$268.4 million aggregate principal amount of the 8.75% Senior Notes were validly tendered as of the expiration date of the consent solicitation. In February 2013, the Partnership accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and paid \$291.4 million to redeem the \$268.4 million principal plus \$11.2 million make-whole premium, \$3.7 million accrued interest and \$8.0 million consent payment. The Partnership entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture.

On March 12, 2013, the Partnership paid \$105.6 million to redeem the remaining \$97.3 million 8.75% Senior Notes not purchased in connection with the tender offer, plus a \$6.3 million make-whole premium and \$2.0 million in accrued interest. The Partnership funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

Capital Leases

The following is a summary of the leased property under capital leases as of June 30, 2014 and December 31, 2013, which are included within property, plant and equipment (see Note 6) (in thousands):

| | June 30, 2014 | December 31, 2013 |
|--|--------------------------|------------------------------|
| Pipelines, processing and compression facilities | \$ 1,142 | \$ 2,281 |
| Less accumulated depreciation | (175) | (330) |
| | \$ 967 | \$ 1,951 |

During the six months ended June 30, 2014, the Partnership took ownership of \$1.1 million of facilities in connection with the conclusion of a capital lease. Depreciation expense for leased properties was \$32 thousand and \$39 thousand for the three months ended June 30, 2014 and 2013, respectively, and \$64 thousand and \$250 thousand for the six months ended June 30, 2014 and 2013, respectively, which is included within depreciation and amortization expense on the Partnership's consolidated statements of operations (see Note 6).

NOTE 14 COMMITMENTS AND CONTINGENCIES

The Partnership has certain long-term unconditional purchase obligations and commitments, consisting primarily of transportation contracts. These agreements provide for transportation services to be used in the ordinary course of the Partnership's operations. Transportation fees paid related to these contracts, including minimum shipment payments, were \$7.9 million and \$3.1 million for the three months ended June 30, 2014 and 2013, respectively, and \$15.2 million and \$6.1 million for the six months ended June 30, 2014 and 2013, respectively. The future fixed and determinable portion of the obligations as of June 30, 2014 was as follows: remainder of 2014 \$3.0 million; 2015 \$3.4 million; 2016 to 2017 \$3.5 million per year; and 2018 \$2.7 million.

The Partnership had committed approximately \$182.4 million for the purchase of property, plant and equipment at June 30, 2014.

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.

Table of Contents**NOTE 15 BENEFIT PLANS***Long-Term Incentive Plans*

The Partnership has a 2004 Long-Term Incentive Plan (2004 LTIP) and a 2010 Long-Term Incentive Plan (2010 LTIP) and collectively with the 2004 LTIP, the LTIPs) in which officers, employees, non-employee managing board members of the General Partner, employees of the General Partner's affiliates and consultants are eligible to participate. The LTIPs are administered by the compensation committee appointed by the General Partner's managing board (the Compensation Committee). Under the LTIPs, the Compensation Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At June 30, 2014, the Partnership had 2,046,819 phantom units outstanding under the Partnership's LTIPs, with 121,946 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options that have vested and have been exercised.

Partnership Phantom Units

Phantom units granted to employees under the LTIPs generally have vesting periods of four years. However, in February 2014, the Partnership granted 227,000 phantom units with a vesting period of three years. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards to non-employee members of the board automatically vest upon a change of control, as defined in the LTIPs. At June 30, 2014, there were 621,295 phantom units outstanding under the LTIPs that will vest within twelve months.

All phantom units outstanding under the LTIPs at June 30, 2014 include distribution equivalent rights (DERs), which are rights 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. The DERs were granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were \$1.0 million and \$0.6 million during the three months ended June 30, 2014 and 2013, respectively, and \$1.9 million and \$1.2 million during the six months ended June 30, 2014 and 2013, respectively. These amounts were recorded as reductions of equity on the Partnership's consolidated balance sheets.

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The following table sets forth the Partnership's LTIPs phantom unit activity for the periods indicated:

| | Three Months Ended June 30, | | | | Six Months Ended June 30, | | | |
|---|-----------------------------|---------------------------|-----------------|---------------------------|---------------------------|---------------------------|-----------------|---------------------------|
| | 2014 | | 2013 | | 2014 | | 2013 | |
| | Number of Units | Fair Value ⁽¹⁾ | Number of Units | Fair Value ⁽¹⁾ | Number of Units | Fair Value ⁽¹⁾ | Number of Units | Fair Value ⁽¹⁾ |
| Outstanding, beginning of period | 1,664,642 | \$ 35.59 | 1,057,083 | \$ 33.22 | 1,446,553 | \$ 36.32 | 1,053,242 | \$ 33.21 |
| Granted | 487,873 | 33.92 | 36,971 | 38.10 | 722,574 | 32.98 | 43,775 | 37.32 |
| Forfeited | (1,450) | 36.34 | (2,100) | 32.95 | (3,650) | 38.25 | (2,100) | 32.95 |
| Matured and issued ⁽²⁾⁽³⁾ | (104,246) | 30.49 | (182,942) | 32.65 | (118,658) | 30.92 | (185,905) | 32.59 |
| Outstanding, end of period ⁽⁴⁾ | 2,046,819 | \$ 35.45 | 909,012 | \$ 33.54 | 2,046,819 | \$ 35.45 | 909,012 | \$ 33.54 |
| Matured and not issued ⁽⁵⁾ | 112,423 | \$ 32.19 | 39,347 | \$ 24.91 | 112,423 | \$ 32.19 | 39,347 | \$ 24.91 |
| Non-cash compensation expense recognized (in thousands) | | \$ 6,443 | | \$ 3,436 | | \$ 12,882 | | \$ 7,820 |

(1) Fair value based upon weighted average grant date price.

(2) The intrinsic values for phantom unit awards exercised during the three months ended June 30, 2014 and 2013 were \$3.3 million and \$6.6 million, respectively, and \$3.8 million and \$6.7 million during the six months ended June 30, 2014 and 2013, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2014 and December 31, 2013 was \$70.4 million and \$50.7 million, respectively.

(4) There were 26,042 and 22,539 outstanding phantom unit awards at June 30, 2014 and December 31, 2013, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.

(5) The aggregate intrinsic value for phantom unit awards vested but not issued at June 30, 2014 and 2013 was \$3.6 million and \$1.5 million, respectively.

At June 30, 2014, the Partnership had approximately \$41.6 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.1 years.

NOTE 16 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 ATLS. 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 its 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 ATLS 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 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 \$1.3 million in each of the three month periods ended June 30, 2014 and 2013, and \$2.5 million in each of the six month periods ended June 30, 2014 and 2013, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the six months ended June 30, 2014 and 2013. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

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The Partnership compresses and gathers gas for Atlas Resource Partners, L.P. (NYSE: ARP) (ARP) on its gathering systems located in Tennessee. ARP 's general partner is wholly-owned by ATLS, and two members of the General Partner 's managing board are members of ARP 's board of directors. The Partnership entered into an agreement to provide these services, which extends for the life of ARP 's leases, in February 2008. The Partnership charged ARP approximately \$0.1 million and \$0.1 million in compression and gathering fees for the three months ended June 30, 2014 and 2013, respectively, and \$0.1 million and \$0.1 million in compression and gathering fees for the six months ended June 30, 2014 and 2013, respectively.

NOTE 17 SEGMENT INFORMATION

As a result of the sale of the Partnership 's subsidiaries owning an interest in WTLPG on May 14, 2014 (see Note 4), the Partnership assessed its reportable segments and realigned its reportable segments into two new segments: Oklahoma Gathering and Processing (Oklahoma) and Texas Gathering and Processing (Texas). These reportable segments reflect the way the Partnership will manage its operations going forward. The Partnership has adjusted its segment presentation from the amounts previously presented to reflect the realignment of the segments.

The Oklahoma segment consists of the SouthOK and WestOK operations, which are comprised of natural gas gathering, processing and treating assets servicing drilling activity in the Anadarko and Arkoma Basins and which were formerly included within the previous Gathering and Processing segment. Oklahoma revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas within the state of Oklahoma.

The Texas segment consists of (1) the SouthTX and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Permian Basin and the Eagle Ford Shale play in south Texas; and (2) the natural gas gathering assets located in the Barnett Shale play in Texas. These assets were formerly included within the previous Gathering and Processing segment. Texas revenues are primarily derived from the sale of residue gas and NGLs and the gathering and processing of natural gas within the state of Texas.

The previous Transportation and Treating segment, which consisted of (1) the gas treating operations, which own contract gas treating facilities located in various shale plays; and (2) the former subsidiaries ' interest in WTLPG, has been eliminated and the financial information is now included within Corporate and Other. The natural gas gathering assets located in the Appalachian Basin in Tennessee, which were formerly included in the previous Gathering and Processing Segment, are now included within Corporate and Other.

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

| | Oklahoma | Texas | Corporate and Other | Consolidated |
|---|------------------|-----------------|------------------------|------------------|
| Three Months Ended June 30, 2014: | | | | |
| Revenue: | | | | |
| Revenues - third party ⁽¹⁾ | \$ 435,346 | \$ 283,221 | \$ (4,702) | \$ 713,865 |
| Revenues - affiliates | | | 91 | 91 |
| Total revenues | 435,346 | 283,221 | (4,611) | 713,956 |
| Costs and Expenses: | | | | |
| Natural gas and liquids cost of sales | 345,711 | 235,174 | | 580,885 |
| Operating expenses | 14,910 | 11,561 | 512 | 26,983 |
| General and administrative ⁽¹⁾ | | | 18,416 | 18,416 |
| Other (revenues) costs | | | (20) | (20) |
| Depreciation and amortization | 26,118 | 21,948 | 1,154 | 49,220 |
| Interest expense ⁽¹⁾ | | | 23,059 | 23,059 |
| Total costs and expenses | 386,739 | 268,683 | 43,121 | 698,543 |
| Equity income (loss) in joint ventures | | (4,760) | 885 | (3,875) |
| Gain on asset disposition | | | 48,465 | 48,465 |
| Income before tax | 48,607 | 9,778 | 1,618 | 60,003 |
| Income tax benefit | (498) | | | (498) |
| Net income | \$ 49,105 | \$ 9,778 | \$ 1,618 | \$ 60,501 |
| Three Months Ended June 30, 2013: | | | | |
| Revenue: | | | | |
| Revenues - third party ⁽¹⁾ | \$ 360,600 | \$ 171,721 | \$ 28,541 | \$ 560,862 |
| Revenues - affiliates | | | 77 | 77 |
| Total revenues | 360,600 | 171,721 | 28,618 | 560,939 |
| Costs and Expenses: | | | | |
| Natural gas and liquids cost of sales | 283,458 | 140,758 | | 424,216 |
| Operating expenses | 16,532 | 7,765 | 473 | 24,770 |
| General and administrative ⁽¹⁾ | | | 12,546 | 12,546 |
| Other costs | | | 18,370 | 18,370 |
| Depreciation and amortization | 30,055 | 13,795 | 2,533 | 46,383 |

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| | | | | |
|--------------------------------------|-----------|----------|-------------|-----------|
| Interest expense ⁽¹⁾ | | | 22,581 | 22,581 |
| Total costs and expenses | 330,045 | 162,318 | 56,503 | 548,866 |
| Equity income in joint ventures | | (2,159) | 1,687 | (472) |
| Loss on asset disposition | (1,519) | | | (1,519) |
| Loss on early extinguishment of debt | | | (19) | (19) |
| Income (loss) before tax | 29,036 | 7,244 | (26,217) | 10,063 |
| Income tax benefit | (28) | | | (28) |
| Net income (loss) | \$ 29,064 | \$ 7,244 | \$ (26,217) | \$ 10,091 |

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| | Oklahoma | Texas | Corporate and Other | Consolidated |
|---|------------------|------------------|------------------------|------------------|
| Six Months Ended June 30, 2014: | | | | |
| Revenue: | | | | |
| Revenues third party ⁽⁴⁾ | \$ 866,370 | \$ 559,780 | \$ (12,336) | \$ 1,413,814 |
| Revenues affiliates | | | 146 | 146 |
| Total revenues | 866,370 | 559,780 | (12,190) | 1,413,960 |
| Costs and Expenses: | | | | |
| Natural gas and liquids cost of sales | 692,355 | 463,998 | | 1,156,353 |
| Operating expenses | 29,143 | 21,914 | 1,054 | 52,111 |
| General and administrative ⁽¹⁾ | | | 36,356 | 36,356 |
| Other costs | | | 17 | 17 |
| Depreciation and amortization | 51,651 | 44,495 | 2,313 | 98,459 |
| Interest expense ⁽¹⁾ | | | 46,722 | 46,722 |
| Total costs and expenses | 773,149 | 530,407 | 86,462 | 1,390,018 |
| Equity income (loss) in joint ventures | | (8,365) | 2,612 | (5,753) |
| Gain on asset disposition | | | 48,465 | 48,465 |
| Income (loss) before tax | 93,221 | 21,008 | (47,575) | 66,654 |
| Income tax benefit | (896) | | | (896) |
| Net income (loss) | \$ 94,117 | \$ 21,008 | \$ (47,575) | \$ 67,550 |
| | Oklahoma | Texas | Corporate and Other | Consolidated |
| Six Months Ended June 30, 2013: | | | | |
| Revenue: | | | | |
| Revenues third party ⁽⁴⁾ | \$ 657,630 | \$ 293,129 | \$ 17,944 | \$ 968,703 |
| Revenues affiliates | | | 148 | 148 |
| Total revenues | 657,630 | 293,129 | 18,092 | 968,851 |
| Costs and Expenses: | | | | |
| Natural gas and liquids cost of sales | 509,900 | 239,856 | | 749,756 |
| Operating expenses | 31,988 | 13,684 | 957 | 46,629 |
| General and administrative ⁽¹⁾ | | | 26,344 | 26,344 |
| Other costs | | | 18,900 | 18,900 |
| Depreciation and amortization | 51,502 | 22,171 | 3,168 | 76,841 |
| Interest expense ⁽¹⁾ | | | 41,267 | 41,267 |
| Total costs and expenses | 593,390 | 275,711 | 90,636 | 959,737 |
| Equity income in joint ventures | | (2,159) | 3,727 | 1,568 |

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| | | | | |
|--------------------------------------|-----------|-----------|-------------|-------------|
| Loss on asset disposition | (1,519) | | | (1,519) |
| Loss on early extinguishment of debt | | | (26,601) | (26,601) |
| Income (loss) before tax | 62,721 | 15,259 | (95,418) | (17,438) |
| Income tax benefit | (37) | | | (37) |
| Net income (loss) | \$ 62,758 | \$ 15,259 | \$ (95,418) | \$ (17,401) |

(1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to the reportable segments as it would be unfeasible to reasonably do so.

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| Capital Expenditures: | Three Months Ended | | Six Months Ended | |
|------------------------------|---------------------------|-------------|-------------------------|-------------|
| | June 30, | | June 30, | |
| | 2014 | 2013 | 2014 | 2013 |
| Oklahoma | \$ 77,764 | \$ 55,352 | \$ 126,552 | \$ 118,804 |
| Texas | 74,185 | 50,620 | 153,312 | 94,772 |
| Corporate and other | 299 | 1,221 | 715 | 2,133 |
| | \$ 152,248 | \$ 107,193 | \$ 280,579 | \$ 215,709 |

| Balance Sheet | June 30, | December 31, |
|--|-----------------|---------------------|
| | 2014 | 2013 |
| Equity method investment in joint ventures: | | |
| Texas | \$ 179,054 | \$ 162,511 |
| Corporate and other | | 85,790 |
| | \$ 179,054 | \$ 248,301 |
| Goodwill: | | |
| Oklahoma | \$ 178,762 | \$ 178,762 |
| Texas | 187,001 | 189,810 |
| | \$ 365,763 | \$ 368,572 |
| Total assets: | | |
| Oklahoma | \$ 2,397,683 | \$ 2,265,231 |
| Texas | 1,995,467 | 1,872,165 |
| Corporate and other | 99,879 | 190,449 |
| | \$ 4,493,029 | \$ 4,327,845 |

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The following table summarizes the Partnership's natural gas and liquids sales by product or service for the periods indicated (in thousands):

| | Three Months Ended | | Six Months Ended | |
|---------------------------------------|--------------------|------------|------------------|------------|
| | June 30, | | June 30, | |
| | 2014 | 2013 | 2014 | 2013 |
| Natural gas and liquids sales: | | | | |
| Natural gas | \$ 285,197 | \$ 191,885 | \$ 556,249 | \$ 333,369 |
| NGLs | 341,695 | 270,240 | 702,449 | 488,071 |
| Condensate | 40,707 | 30,444 | 71,888 | 55,009 |
| Other | (50) | (1,339) | 93 | (1,371) |
| Total | \$ 667,549 | \$ 491,230 | \$ 1,330,679 | \$ 875,078 |

NOTE 18 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership's Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership's consolidated financial statements as of June 30, 2014 and December 31, 2013 and for the three and six months ended June 30, 2014 and 2013 include the financial statements of Atlas Pipeline Mid-Continent WestOK, LLC (WestOK, LLC), Atlas Pipeline Mid-Continent WestTex, LLC (WestTex, LLC) and Centrahoma Processing, LLC (Centrahoma), as well as the equity interest of two of the Partnership's subsidiaries in WTLPG, prior to the sale on May 14, 2014 (see Note 4), and the equity interests in the T2 Joint Ventures. Under the terms of the Senior Notes and the revolving credit facility, WestOK, LLC, WestTex, LLC, Centrahoma and the T2 Joint Ventures 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 June 30, 2014 and December 31, 2013 and for the three and six months ended June 30, 2014 and 2013. 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):

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| Balance Sheets June 30, 2014 | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
|---|---------------------|-----------------------------------|---------------------------------------|--------------------------------------|---------------------|
| Assets | | | | | |
| Cash and cash equivalents | \$ | \$ 170 | \$ 3,904 | \$ | \$ 4,074 |
| Accounts receivable affiliates | | 210,759 | | (210,759) | |
| Other current assets | 134 | 46,553 | 235,765 | (950) | 281,502 |
| Total current assets | 134 | 257,482 | 239,669 | (211,709) | 285,576 |
| Property, plant and equipment, net | | 848,833 | 2,135,335 | | 2,984,168 |
| Intangible assets, net | | 554,237 | 79,849 | | 634,086 |
| Goodwill | | 320,869 | 44,894 | | 365,763 |
| Equity method investment in joint ventures | | | 179,054 | | 179,054 |
| Long term portion of derivative assets | | 451 | | | 451 |
| Long term notes receivable | | | 1,852,928 | (1,852,928) | |
| Equity investments | 4,122,015 | 970,042 | | (5,092,057) | |
| Other assets, net | 37,714 | 1,787 | 4,430 | | 43,931 |
| Total assets | \$ 4,159,863 | \$ 2,953,701 | \$ 4,536,159 | \$ (7,156,694) | \$ 4,493,029 |
| Liabilities and Equity | | | | | |
| Accounts payable affiliates | \$ 78,741 | \$ | \$ 136,320 | \$ (210,759) | \$ 4,302 |
| Other current liabilities | 27,201 | 97,761 | 270,285 | | 395,247 |
| Total current liabilities | 105,942 | 97,761 | 406,605 | (210,759) | 399,549 |
| Long-term portion of derivative liabilities | | 216 | | | 216 |
| Long-term debt, less current portion | 1,654,219 | 100 | | | 1,654,319 |
| Deferred income taxes, net | | 32,394 | | | 32,394 |
| Other long-term liabilities | 162 | 849 | 6,000 | | 7,011 |
| Equity | 2,399,540 | 2,822,381 | 4,123,554 | (6,945,935) | 2,399,540 |
| Total liabilities and equity | \$ 4,159,863 | \$ 2,953,701 | \$ 4,536,159 | \$ (7,156,694) | \$ 4,493,029 |

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| December 31, 2013 | Parent | Guarantor Subsidiaries | Non- Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
|---|---------------------|-----------------------------------|--|--------------------------------------|---------------------|
| Assets | | | | | |
| Cash and cash equivalents | \$ | \$ 168 | \$ 4,746 | \$ | \$ 4,914 |
| Accounts receivable affiliates | 765,236 | | | (765,236) | |
| Other current assets | 215 | 52,910 | 185,975 | (2,236) | 236,864 |
| Total current assets | 765,451 | 53,078 | 190,721 | (767,472) | 241,778 |
| Property, plant and equipment, net | | 723,302 | 2,000,890 | | 2,724,192 |
| Intangible assets, net | | 603,533 | 92,738 | | 696,271 |
| Goodwill | | 323,678 | 44,894 | | 368,572 |
| Equity method investment in joint venture | | | 248,301 | | 248,301 |
| Long term portion of derivative assets | | 2,270 | | | 2,270 |
| Long term notes receivable | | | 1,852,928 | (1,852,928) | |
| Equity investments | 3,186,938 | 1,487,358 | | (4,674,296) | |
| Other assets, net | 41,094 | 1,787 | 3,580 | | 46,461 |
| Total assets | \$ 3,993,483 | \$ 3,195,006 | \$ 4,434,052 | \$ (7,294,696) | \$ 4,327,845 |
| Liabilities and Equity | | | | | |
| Accounts payable affiliates | \$ | \$ 423,078 | \$ 345,070 | \$ (765,236) | \$ 2,912 |
| Other current liabilities | 26,819 | 75,031 | 215,464 | | 317,314 |
| Total current liabilities | 26,819 | 498,109 | 560,534 | (765,236) | 320,226 |
| Long-term portion of derivative liabilities | | 320 | | | 320 |
| Long-term debt, less current portion | 1,706,556 | 230 | | | 1,706,786 |
| Deferred income taxes, net | | 33,290 | | | 33,290 |
| Other long-term liabilities | 203 | 1,115 | 6,000 | | 7,318 |
| Equity | 2,259,905 | 2,661,942 | 3,867,518 | (6,529,460) | 2,259,905 |
| Total liabilities and equity | \$ 3,993,483 | \$ 3,195,006 | \$ 4,434,052 | \$ (7,294,696) | \$ 4,327,845 |

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| Statements of Operations | Parent | Guarantor Subsidiaries | Non- Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
|---|-----------|---------------------------|-----------------------------------|------------------------------|--------------|
| Three Months Ended June 30, 2014 | | | | | |
| Total revenues | \$ | \$ 129,504 | \$ 588,248 | \$ (3,796) | \$ 713,956 |
| Total costs and expenses | (23,215) | (153,351) | (525,773) | 3,796 | (698,543) |
| Equity income (loss) | 79,751 | 54,635 | (3,875) | (134,386) | (3,875) |
| Gain on asset disposition | | 48,465 | | | 48,465 |
| Income (loss), before tax | 56,536 | 79,253 | 58,600 | (134,386) | 60,003 |
| Income tax benefit | | (498) | | | (498) |
| Net income (loss) | 56,536 | 79,751 | 58,600 | (134,386) | 60,501 |
| Income attributable to non-controlling interest | | | (3,965) | | (3,965) |
| Preferred unit imputed dividend effect | (11,378) | | | | (11,378) |
| Preferred unit dividends in kind | (10,406) | | | | (10,406) |
| Preferred unit dividends | (2,609) | | | | (2,609) |
| Net income (loss) attributable to common limited partners and the General Partner | \$ 32,143 | \$ 79,751 | \$ 54,635 | \$ (134,386) | \$ 32,143 |
| Three Months Ended June 30, 2013 | | | | | |
| Total revenues | \$ | \$ 158,014 | \$ 425,516 | \$ (22,591) | \$ 560,939 |
| Total costs and expenses | (21,332) | (164,950) | (384,580) | 21,996 | (548,866) |
| Equity income (loss) | 29,635 | 38,654 | | (68,761) | (472) |
| Loss on early extinguishment of debt | (19) | | | | (19) |
| Loss on asset disposition | | (1,519) | | | (1,519) |
| Income (loss), before tax | 8,284 | 30,199 | 40,936 | (69,356) | 10,063 |
| Income tax benefit | | (28) | | | (28) |
| Net income (loss) | 8,284 | 30,227 | 40,936 | (69,356) | 10,091 |
| Income attributable to non-controlling interest | | | (1,810) | | (1,810) |
| Preferred unit imputed dividend effect | | (6,729) | | | (6,729) |
| Preferred unit dividends in kind | | (5,341) | | | (5,341) |
| Preferred unit dividends | | | | | |
| Net income (loss) attributable to common limited partners and the General Partner | \$ 8,284 | \$ 18,157 | \$ 39,126 | \$ (69,356) | \$ (3,789) |

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| Statements of Operations | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
|---|-------------|---------------------------|-------------------------------|------------------------------|--------------|
| Six Months Ended June 30, 2014 | | | | | |
| Total revenues | \$ | \$ 276,340 | \$ 1,144,786 | \$ (7,166) | \$ 1,413,960 |
| Total costs and expenses | (47,020) | (325,215) | (1,024,949) | 7,166 | (1,390,018) |
| Equity income (loss) | 108,143 | 107,657 | (5,753) | (215,800) | (5,753) |
| Gain on asset disposition | | 48,465 | | | 48,465 |
| Income (loss), before tax | 61,123 | 107,247 | 114,084 | (215,800) | 66,654 |
| Income tax benefit | | (896) | | | (896) |
| Net income (loss) | 61,123 | 108,143 | 114,084 | (215,800) | 67,550 |
| Income attributable to non-controlling interest | | | (6,427) | | (6,427) |
| Preferred unit imputed dividend effect | (22,756) | | | | (22,756) |
| Preferred unit dividends in kind | (20,125) | | | | (20,125) |
| Preferred unit dividends | (3,015) | | | | (3,015) |
| Net income (loss) attributable to common limited partners and the General Partner | \$ 15,227 | \$ 108,143 | \$ 107,657 | \$ (215,800) | \$ 15,227 |
| Six Months Ended June 30, 2013 | | | | | |
| Total revenues | \$ | \$ 249,856 | \$ 760,887 | \$ (41,892) | \$ 968,851 |
| Total costs and expenses | (39,929) | (279,176) | (681,929) | 41,297 | (959,737) |
| Equity income (loss) | 45,951 | 77,348 | | (121,731) | 1,568 |
| Loss on early extinguishment of debt | (26,601) | | | | (26,601) |
| Loss on asset disposition | | (1,519) | | | (1,519) |
| Income (loss), before tax | (20,579) | 46,509 | 78,958 | (122,326) | (17,438) |
| Income tax benefit | | (37) | | | (37) |
| Net income (loss) | (20,579) | 46,546 | 78,958 | (122,326) | (17,401) |
| Income attributable to non-controlling interest | | | (3,179) | | (3,179) |
| Preferred unit imputed dividend effect | | (6,729) | | | (6,729) |
| Preferred unit dividends in kind | | (5,341) | | | (5,341) |
| Preferred unit dividends | | | | | |
| Net income (loss) attributable to common limited partners and the General Partner | \$ (20,579) | \$ 34,476 | \$ 75,779 | \$ (122,326) | \$ (32,650) |

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| Statements of Cash Flows | Parent | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Adjustments | Consolidated |
|--|--------------|---------------------------|-------------------------------|------------------------------|--------------|
| Six Months Ended June 30, 2014 | | | | | |
| Net cash provided by (used in): | | | | | |
| Operating activities | \$ 311,927 | \$ 108,955 | \$ 171,974 | \$ (452,947) | \$ 139,909 |
| Investing activities | (321,923) | (140,298) | (105,953) | 417,762 | (150,412) |
| Financing activities | 9,996 | 31,345 | (66,863) | 35,185 | 9,663 |
| Net change in cash and cash equivalents | | | | | |
| | | 2 | (842) | | (840) |
| Cash and cash equivalents, beginning of period | | 168 | 4,746 | | 4,914 |
| Cash and cash equivalents, end of period | | | | | |
| | \$ | \$ 170 | \$ 3,904 | \$ | \$ 4,074 |
| Six Months Ended June 30, 2013 | | | | | |
| Net cash provided by (used in): | | | | | |
| Operating activities | \$ (371,569) | \$ 69,916 | \$ 92,738 | \$ 280,636 | \$ 71,721 |
| Investing activities | (807,215) | (978,215) | (213,535) | 782,721 | (1,216,244) |
| Financing activities | 1,178,784 | 947,617 | 99,162 | (1,063,357) | 1,162,206 |
| Net change in cash and cash equivalents | | | | | |
| | | 39,318 | (21,635) | | 17,683 |
| Cash and cash equivalents, beginning of period | | 157 | 3,241 | | 3,398 |
| Cash and cash equivalents, end of period | | | | | |
| | \$ | \$ 39,475 | \$ (18,394) | \$ | \$ 21,081 |

NOTE 19 SUBSEQUENT EVENTS

On July 23, 2014, the Partnership declared a cash distribution of \$0.63 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2014. The \$58.8 million distribution, including \$7.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2014 to unitholders of record at the close of business on August 7, 2014 (see Note 5). Based on this declaration, the Partnership will also issue approximately 305,000 additional Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution in kind for the quarter ended June 30, 2014.

On July 15, 2014, the Partnership paid a cash distribution of \$0.67604 per unit, or approximately \$3.4 million, on its Class E Preferred Units, representing the cash distribution for the period March 17, 2014 to July 14, 2014.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements

When used in this Form 10-Q, the words **believes**, **anticipates**, **expects** and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 1A, under the caption **Risk Factors**, in our Annual Report on Form 10-K for the year ended December 31, 2013. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

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 and with our Annual Report on Form 10-K for the year ended December 31, 2013.

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, processing and treating services in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States, and a provider of natural gas gathering services in the Appalachian Basin in the northeastern region of the United States.

As a result of the sale of two former subsidiaries holding an interest in West Texas LPG Pipeline Limited Partnership (**WTLPG**) on May 14, 2014 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 4 West Texas LPG Limited Partnership), we assessed our reportable segments and realigned them into two new segments: Oklahoma Gathering and Processing (**Oklahoma**) and Texas Gathering and Processing (**Texas**). These reportable segments reflect the way we will manage our operations going forward.

The Oklahoma segment consists of the SouthOK and WestOK operations, which are comprised of natural gas gathering, processing and treating assets servicing drilling activity in the Anadarko and Arkoma Basins of Oklahoma. The Texas segment consists of (1) the SouthTX and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Permian Basin and the Eagle Ford Shale play in south Texas; and (2) natural gas gathering assets located in the Barnett Shale play in Texas. Revenues for both segments are primarily derived from the sale of residue gas and NGLs and the gathering and processing of natural gas.

The previous Transportation and Treating segment, which consisted of (1) the gas treating operations, which own contract gas treating facilities located in various shale plays; and (2) two subsidiaries holding an interest in WTLPG, has been eliminated and the financial information is now included within Corporate and Other. The natural gas gathering assets located in the Appalachian Basin in Tennessee, which were formerly included in the previous Gathering and Processing Segment, are now included within Corporate and Other.

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As of June 30, 2014, our Oklahoma segment owns, has interests in and operates ten natural gas processing plants with aggregate capacity of approximately 950 MMCFD, a gas treating facility and approximately 7,100 miles of active natural gas gathering systems located in Oklahoma and Kansas. As of June 30, 2014, our Texas segment owns, has interests in and operates six natural gas processing plants with aggregate capacity of approximately 850 MMCFD and approximately 4,100 miles of active natural gas gathering systems located in Texas. Our gathering systems gather natural gas from oil and natural gas wells and central delivery points and deliver this gas to processing plants, as well as third-party pipelines.

Our Oklahoma and Texas segments are all located in or near areas of abundant and long-lived natural gas production. In Oklahoma, our operations are in or near the Golden Trend, Mississippian Limestone and Hugoton field in the Anadarko Basin and the Woodford Shale. In Texas, our operations are in or near the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin; the Barnett Shale; and the Eagle Ford Shale. Our gathering systems are connected to primarily individual well connections and, secondarily, central delivery points, which are linked to multiple wells. We believe we have significant scale in each of our primary service areas. We provide gathering, processing and treating services to the wells connected to our systems, primarily under long-term contracts. As a result of the location and capacity of our gathering, processing and treating assets, we believe we are strategically positioned to capitalize on the drilling activity in our service areas.

Recent Events

On June 25, 2014, we placed in service a new 200 MMCFD cryogenic processing plant, known as the Silver Oak II plant, in our SouthTX system in the Eagleford Shale play of South Texas, increasing the SouthTX system capacity to 400 MMCFD.

On May 14, 2014, we completed the sale of two indirect subsidiaries, which held an aggregate 20% interest in WTLPG, to a subsidiary of Martin Midstream Partners L.P. (NYSE: MMLP). We received \$132.7 million in proceeds, net of selling costs, which were used to pay down the revolving credit facility. As a result of the sale, we recorded a \$48.5 million gain on asset dispositions on our consolidated statements of operations for the three and six months ended June 30, 2014. (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 4 West Texas LPG Pipeline Limited Partnership).

On May 12, 2014, we entered into an Equity Distribution Agreement (the 2014 EDA) with Citigroup Global Markets Inc., Wells Fargo Securities, LLC and MLV & Co. LLC (together, the Sales Agents). Pursuant to the 2014 EDA, we may offer and sell from time to time through our Sales Agents, common units having an aggregate value of up to \$250.0 million. Sales are at market prices prevailing at the time of the sale. (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Common Units).

On May 1, 2014, we placed in service a new 120 MMCFD cryogenic processing plant, known as the Stonewall plant, in our SouthOK system in the Arkoma Basin of Oklahoma, increasing the SouthOK system capacity to 500 MMCFD.

On March 17, 2014, we issued 5,060,000 of our Class E Preferred Units to the public at an offering price of \$25.00 per Class E Preferred Unit. We received \$122.3 million in net proceeds. The proceeds were used to pay down the revolving credit facility (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Class E Preferred Units).

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On March 11, 2014, we entered into an amendment to the credit agreement governing our revolving credit facility which, among other changes:

adjusted the duration of, and maximum ratios allowed during, the Acquisition Period, as defined in the credit agreement, for the Consolidated Funded Debt Ratio, as defined in the credit agreement; and

permitted the payment of cash distributions, if any, on the Class E cumulative redeemable perpetual preferred units (Class E Preferred Units) so long as we have a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to \$50 million.

Subsequent Events

On July 23, 2014, we declared a cash distribution of \$0.63 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2014. The \$58.8 million distribution, including \$7.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2014 to unitholders of record at the close of business on August 7, 2014 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Cash Distributions). Based on this declaration, we will also distribute approximately 305,000 additional Class D convertible preferred units (Class D Preferred Units) to the holders of the Class D Preferred Units as a preferred unit distribution for the quarter ended June 30, 2014.

On July 15, 2014, we paid a cash distribution of \$0.67604 per unit, or approximately \$3.4 million, on our Class E Preferred Units, representing the cash distribution for the period March 17, 2014 through July 14, 2014 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Class E Preferred Units).

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.

We face competition 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, quality of assets, flexibility, service history 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 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.

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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, NGLs and crude oil. We believe 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. However, energy market uncertainty has negatively impacted North American drilling activity in the past. Lower drilling levels and shut-in wells over a sustained period would have a negative effect on natural gas volumes gathered, processed and treated.

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-based derivative instruments such as natural gas, crude oil and NGL financial contracts to hedge a portion of the value of our assets and operations from such price risks.

Currently, there is a significant 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 ability to raise additional capital, and an increase in the volatility of the price of our common units.

How We Evaluate Our Operations

Our principal revenue is generated from the gathering, processing and treating of natural gas; the sale of natural gas, NGLs and condensate; the transportation of NGLs; and the leasing of gas treating facilities. Our profitability is a function of the difference between the revenues we receive and the costs associated with conducting our operations, including the cost of natural gas, NGLs and condensate we purchase as well as operating and general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Variables that affect our profitability include:

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

the price of the natural gas we gather; process and treat; and the NGLs and condensate we recover and sell, which is a function of the relevant supply and demand in the mid-continent and northeastern areas of the United States;

the NGL and BTU content of the gas gathered and processed;

the contract terms with each producer; and

the efficiency of our gathering systems and processing and treating plants.

Our management uses a variety of financial measures and operational measurements other than our GAAP financial statements to analyze our performance. These include: (1) volumes, (2) operating expenses and (3) the following non-GAAP measures gross margin, EBITDA, adjusted EBITDA and distributable cash flow. Our management views these measures as important performance measures of core profitability for our operations and as key components of our internal financial reporting. We believe investors benefit from having access to the same financial measures that our management uses.

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Volumes. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our gathering, processing and treating systems. This is achieved by connecting new wells and adding new volumes in existing areas of production. Our performance at our plants is also significantly impacted by the quality of the natural gas we process, the NGL content of the natural gas and the plants' recovery capability. In addition, we monitor fuel consumption and losses because they have a significant impact on the gross margin realized from our processing operations.

Operating Expenses. Plant operating, 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, ad valorem taxes and other overhead costs.

Gross Margins. We define gross margin as natural gas and liquids sales revenue plus transportation, processing and other fee revenues less purchased product costs, subject to certain non-cash adjustments. Product costs include the cost of natural gas, NGLs and condensate we purchase from third parties. Gross margin, as we define it, does not include plant operating expenses; transportation and compression expenses; and derivative gain (loss) related to undesignated hedges, as movements in gross margin generally do not result in directly correlated movements in these categories.

Gross margin is a non-GAAP measure. The GAAP measure most directly comparable to gross margin is net income. Gross margin is not an alternative to GAAP net income and has important limitations as an analytical tool. Investors should not consider gross margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of gross margin may not be comparable to gross margin measures of other companies, thereby diminishing its utility.

EBITDA and Adjusted EBITDA. EBITDA represents net income (loss) before interest expense, income taxes, 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, impairment charges and other cash items such as non-recurring cash derivative early termination expense. The GAAP measure most directly comparable to EBITDA and Adjusted EBITDA is net income. 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 Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies. The Adjusted EBITDA calculation is similar to the Consolidated EBITDA calculation utilized within the financial covenants under our credit facility, with the exception that Adjusted EBITDA includes certain non-cash items specifically excluded under our credit facility and excludes the capital expansion add back included in Consolidated EBITDA as defined in the credit facility (see [Revolving Credit Facility](#)).

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity's financial performance, such as cost of capital and 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 GAAP or as indicators of our operating performance or liquidity. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our unit holders.

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Distributable Cash Flow. We define distributable cash flow as net income plus tax, depreciation and amortization; amortization of deferred financing costs included in interest expense; and non-cash gain (losses) on derivative contracts, less income attributable to non-controlling interests, preferred unit dividends, maintenance capital expenditures, gains (losses) on asset sales and other non-cash gains (losses).

Distributable cash flow is a significant performance metric used by our management and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can compute the ratio of distributable cash flow per unit to the declared cash distribution per unit to determine the rate at which the distributable cash flow covers the distribution. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships because the value of a unit of such an entity is generally determined by the unit's yield, which in turn is based on the amount of cash distributions the entity pays to a unitholder.

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income or GAAP cash flows from operating activities. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Table of Contents**Non-GAAP Financial Measures**

The following tables reconcile the non-GAAP financial measurements used by management to their most directly comparable GAAP measures for the three and six months ended June 30, 2014 and 2013 (in thousands):

RECONCILIATION OF GROSS MARGIN

| | Three Months Ended | | Six Months Ended | |
|---|---------------------------|-------------------|-------------------------|-------------------|
| | June 30, | | June 30, | |
| | 2014 | 2013 | 2014 | 2013 |
| Net income (loss) | \$ 60,501 | \$ 10,091 | \$ 67,550 | \$ (17,401) |
| Adjustments: | | | | |
| Derivative (gain) loss, net | 6,367 | (27,107) | 15,038 | (15,024) |
| Other income, net | (2,731) | (2,296) | (4,839) | (5,718) |
| Operating expenses ⁽¹⁾ | 26,963 | 43,140 | 52,128 | 65,529 |
| General and administrative expense ⁽²⁾ | 18,416 | 12,546 | 36,356 | 26,344 |
| Depreciation and amortization | 49,220 | 46,383 | 98,459 | 76,841 |
| Interest | 23,059 | 22,581 | 46,722 | 41,267 |
| Income tax benefit | (498) | (28) | (896) | (37) |
| Equity (income) loss in joint ventures | 3,875 | 472 | 5,753 | (1,568) |
| Loss on early extinguishment of debt | | 19 | | 26,601 |
| (Gain) loss on asset sales and other | (48,465) | 1,519 | (48,465) | 1,519 |
| Non-cash linefill (gain) loss ⁽³⁾ | 49 | 1,339 | (94) | 1,371 |
| Gross margin | \$ 136,756 | \$ 108,659 | \$ 267,712 | \$ 199,724 |

- (1) Operating expenses include plant operating expenses; transportation and compression expenses; and other costs.
(2) General and administrative includes compensation reimbursement to affiliates.
(3) Represents the non-cash impact of commodity price movements on pipeline linefill.

Table of Contents**RECONCILIATION OF EBITDA, ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW**

| | Three Months Ended | | Six Months Ended | |
|---|--------------------|-----------|------------------|-------------|
| | June 30, | | June 30, | |
| | 2014 | 2013 | 2014 | 2013 |
| Net income (loss) | \$ 60,501 | \$ 10,091 | \$ 67,550 | \$ (17,401) |
| Adjustments: | | | | |
| Interest expense | 23,059 | 22,581 | 46,722 | 41,267 |
| Income tax benefit | (498) | (28) | (896) | (37) |
| Depreciation and amortization | 49,220 | 46,383 | 98,459 | 76,841 |
| EBITDA | 132,282 | 79,027 | 211,835 | 100,670 |
| Adjustments: | | | | |
| Income attributable to non-controlling interests ⁽¹⁾ | (3,965) | (1,810) | (6,427) | (3,179) |
| Non-controlling interest depreciation, amortization and interest expense ⁽²⁾ | (906) | (1,121) | (1,612) | (1,971) |
| Equity (income) loss in joint ventures | 3,875 | 472 | 5,753 | (1,568) |
| Distributions from joint ventures | 2,200 | 1,800 | 4,200 | 3,600 |
| Loss on early extinguishment of debt | | 19 | | 26,601 |
| (Gain) loss on asset disposition | (48,465) | 1,519 | (48,465) | 1,519 |
| Non-cash gain on derivatives | (252) | (24,263) | (1,416) | (10,544) |
| Premium expense on derivative instruments | 892 | 3,745 | 3,515 | 7,020 |
| Unrecognized economic impact of acquisitions | | 1,126 | | 1,126 |
| Other (revenues) costs | (20) | 18,370 | 17 | 18,900 |
| Non-cash compensation | 6,443 | 3,436 | 12,882 | 7,820 |
| Non-cash line fill (gain) loss ⁽³⁾ | 49 | 1,339 | (94) | 1,371 |
| Minimum volume adjustment ⁽⁴⁾ | 754 | 2,653 | 3,503 | 2,653 |
| Adjusted EBITDA | 92,887 | 86,312 | 183,691 | 154,018 |
| Adjustments: | | | | |
| Interest expense | (23,059) | (22,581) | (46,722) | (41,267) |
| Preferred dividend obligation | (2,609) | | (3,015) | |
| Amortization of deferred finance costs | 1,874 | 1,739 | 3,730 | 3,283 |
| Premium expense on derivative instruments | (892) | (3,745) | (3,515) | (7,020) |
| Maintenance capital, net ⁽⁵⁾ | (5,405) | (3,713) | (10,538) | (7,527) |
| Distributable Cash Flow | \$ 62,796 | \$ 58,012 | \$ 123,631 | \$ 101,487 |

(1) Represents Anadarko Petroleum Corporation's (Anadarko (NYSE: APC)) non-controlling interest in the operating results of Atlas Pipeline Mid-Continent WestOk, LLC (WestOK) and Atlas Pipeline Mid-Continent WestTex, LLC (WestTX); and MarkWest Oklahoma Gas Company, LLC's, (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE) non-controlling interest in Centrahoma Processing, LLC (Centrahoma).

(2)

Represents the depreciation, amortization and interest expense included in income attributable to non-controlling interest for MarkWest's interest in Centrahoma.

- (3) Represents the non-cash impact of commodity price movements on pipeline linefill.
- (4) Represents minimum volume adjustments on certain producer throughput contracts.
- (5) Net of non-controlling interest maintenance capital of \$150 thousand and \$135 thousand for the three months ended June 30, 2014 and 2013, respectively, and \$342 thousand and \$176 thousand for the six months ended June 30, 2014 and 2013, respectively.

Table of Contents**Results of Operations**

The following tables illustrate selected pricing before the effect of derivatives and volumetric information for the periods indicated:

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|--------------------------------------|--------------------------------|---------|-------------------|------------------------------|---------|-------------------|
| | 2014 | 2013 | Percent Change | 2014 | 2013 | Percent Change |
| Pricing: | | | | | | |
| Weighted Average Market Prices: | | | | | | |
| NGL price per gallon Conway hub | \$ 0.87 | \$ 0.75 | 16.0% | \$ 0.94 | \$ 0.79 | 19.0% |
| NGL price per gallon Mt. Belvieu hub | 0.87 | 0.80 | 8.7% | 0.92 | 0.83 | 10.8% |
| Oklahoma | | | | | | |
| Natural gas sales (\$/Mcf): | | | | | | |
| SouthOK | 4.29 | 3.88 | 10.6% | 4.52 | 3.53 | 28.0% |
| WestOK | 4.16 | 3.84 | 8.3% | 4.44 | 3.54 | 25.4% |
| NGL sales (\$/gallon): | | | | | | |
| SouthOK | 1.00 | 0.71 | 40.8% | 1.03 | 0.69 | 49.3% |
| WestOK | 1.11 | 0.96 | 15.6% | 1.15 | 0.97 | 18.6% |
| Condensate sales (\$/barrel): | | | | | | |
| SouthOK | 96.45 | 91.76 | 5.1% | 92.96 | 90.89 | 2.3% |
| WestOK | 96.71 | 84.53 | 14.4% | 91.36 | 84.10 | 8.6% |
| Texas | | | | | | |
| Natural gas sales (\$/Mcf): | | | | | | |
| WestTX | 4.23 | 3.74 | 13.1% | 4.46 | 3.45 | 29.3% |
| NGL sales (\$/gallon): | | | | | | |
| SouthTX | 0.76 | 0.75 | 1.3% | 0.93 | 0.75 | 24.0% |
| WestTX | 0.93 | 0.86 | 8.1% | 0.96 | 0.89 | 7.9% |
| Condensate sales (\$/barrel): | | | | | | |
| SouthTX | 87.14 | 92.78 | (6.1)% | 86.57 | 92.78 | (6.7)% |
| WestTX | 95.02 | 93.96 | 1.1% | 96.25 | 91.97 | 4.7% |
| Weighted Average | | | | | | |
| Natural gas sales (\$/Mcf): | 4.19 | 3.82 | 9.7% | 4.45 | 3.59 | 24.0% |
| NGL sales (\$/gallon): | 0.98 | 0.84 | 16.7% | 1.02 | 0.84 | 21.4% |
| Condensate sales (\$/barrel): | 95.78 | 89.15 | 7.4% | 92.74 | 88.09 | 5.3% |

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| | Three Months Ended | | | Six Months Ended | | |
|-----------------------------------|--------------------|---------|-------------------|------------------|---------|-------------------|
| | June 30, | | Percent Change | June 30, | | Percent Change |
| | 2014 | 2013 | | 2014 | 2013 | |
| Operating data: | | | | | | |
| Oklahoma | | | | | | |
| SouthOK system ⁽¹⁾ : | | | | | | |
| Gathered gas volume (MCFD) | 433,294 | 422,974 | 2.4% | 416,590 | 407,323 | 2.3% |
| Processed gas volume (MCFD) | 408,615 | 334,812 | 22.0% | 390,733 | 330,767 | 18.1% |
| Residue gas volume (MCFD) | 378,325 | 319,650 | 18.4% | 356,980 | 314,892 | 13.4% |
| NGL volume (BPD) | 29,344 | 41,791 | (29.8)% | 28,810 | 37,841 | (23.9)% |
| Condensate volume (BPD) | 585 | 536 | 9.1% | 693 | 550 | 26.0% |
| WestOK system: | | | | | | |
| Gathered gas volume (MCFD) | 554,233 | 506,487 | 9.4% | 543,003 | 479,577 | 13.2% |
| Processed gas volume (MCFD) | 530,455 | 483,504 | 9.7% | 520,364 | 454,628 | 14.5% |
| Residue gas volume (MCFD) | 488,224 | 444,670 | 9.8% | 477,805 | 420,815 | 13.5% |
| NGL volume (BPD) | 23,678 | 22,233 | 6.5% | 23,346 | 19,258 | 21.2% |
| Condensate volume (BPD) | 2,420 | 1,949 | 24.2% | 2,292 | 1,959 | 17.0% |
| Texas | | | | | | |
| SouthTX system: | | | | | | |
| Gathered gas volume (MCFD) | 118,133 | 122,245 | (3.4)% | 107,293 | 122,245 | (12.2)% |
| Processed gas volume (MCFD) | 114,623 | 121,338 | (5.5)% | 104,249 | 121,338 | (14.1)% |
| Residue gas volume (MCFD) | 94,537 | 96,606 | (2.1)% | 85,317 | 96,606 | (11.7)% |
| NGL volume (BPD) | 13,805 | 15,041 | (8.2)% | 12,843 | 15,041 | (14.6)% |
| Condensate volume (BPD) | 171 | 65 | 163.1% | 159 | 65 | 144.6% |
| WestTX system ⁽¹⁾ : | | | | | | |
| Gathered gas volume (MCFD) | 460,410 | 352,865 | 30.5% | 434,614 | 332,829 | 30.6% |
| Processed gas volume (MCFD) | 439,447 | 313,504 | 40.2% | 414,867 | 297,220 | 39.6% |
| Residue gas volume (MCFD) | 327,994 | 229,777 | 42.7% | 307,577 | 219,889 | 39.9% |
| NGL volume (BPD) | 56,165 | 39,901 | 40.8% | 53,231 | 36,591 | 45.5% |
| Condensate volume (BPD) | 2,219 | 1,993 | 11.3% | 1,708 | 1,516 | 12.7% |
| Barnett system: | | | | | | |
| Average throughput volumes (MCFD) | 20,657 | 20,081 | 2.9% | 20,281 | 20,737 | (2.2)% |

(1) Operating data for SouthOK and WestTX represent 100% of operating activity for these systems. SouthOK gathered volumes include volumes gathered by MarkWest and processed through the Arkoma facilities.

Table of Contents**Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013**

The following table and discussion is a summary of our consolidated results of operations for the three months ended June 30, 2014 and 2013 (in thousands):

| | Three Months Ended June 30, | | | Percent Change |
|---|--|-------------|-----------------|---------------------------|
| | 2014 | 2013 | Variance | |
| <i>Gross margin</i> ⁽¹⁾ | | | | |
| Natural gas and liquids sales | \$ 667,549 | \$ 491,230 | \$ 176,319 | 35.9% |
| Transportation, processing and other fees | 50,043 | 40,306 | 9,737 | 24.2% |
| Less: non-cash line fill loss ⁽²⁾ | (49) | (1,339) | 1,290 | 96.3% |
| Less: natural gas and liquids cost of sales | 580,885 | 424,216 | 156,669 | 36.9% |
| Gross margin | 136,756 | 108,659 | 28,097 | 25.9% |
| Gross margin % | 20.5% | 22.1% | | |
| <i>Expenses:</i> | | | | |
| Operating expenses | 26,983 | 24,770 | 2,213 | 8.9% |
| General and administrative ⁽³⁾ | 18,416 | 12,546 | 5,870 | 46.8% |
| Other (revenues) costs | (20) | 18,370 | (18,390) | (100.1)% |
| Depreciation and amortization | 49,220 | 46,383 | 2,837 | 6.1% |
| Interest expense | 23,059 | 22,581 | 478 | 2.1% |
| Total expenses | 117,658 | 124,650 | (6,992) | (5.6)% |
| <i>Other income items:</i> | | | | |
| Derivative gain (loss), net | (6,367) | 27,107 | (33,474) | (123.5)% |
| Other income, net | 2,731 | 2,296 | 435 | 18.9% |
| Non-cash line fill loss ⁽²⁾ | (49) | (1,339) | 1,290 | 96.3% |
| Equity loss in joint ventures | (3,875) | (472) | (3,403) | (721.0)% |
| Gain (loss) on asset disposition | 48,465 | (1,519) | 49,984 | 3,290.6% |
| Loss on early extinguishment of debt | | (19) | 19 | 100.0% |
| Income tax benefit | 498 | 28 | 470 | 1,678.6% |
| Income attributable to non-controlling interests ⁽⁴⁾ | (3,965) | (1,810) | (2,155) | (119.1)% |
| Preferred unit imputed dividend effect | (11,378) | (6,729) | (4,649) | (69.1)% |
| Preferred unit dividends in kind | (10,406) | (5,341) | (5,065) | (94.8)% |
| Preferred unit dividends | (2,609) | | (2,609) | (100.0)% |
| Net income (loss) attributable to common limited partners and General Partner | \$ 32,143 | \$ (3,789) | \$ 35,932 | 948.3% |
| <i>Non-GAAP financial data:</i> | | | | |
| EBITDA ⁽¹⁾ | \$ 132,282 | \$ 79,027 | \$ 53,255 | 67.4% |
| Adjusted EBITDA ⁽¹⁾ | 92,887 | 86,312 | 6,575 | 7.6% |
| Distributable cash flow ⁽¹⁾ | 62,796 | 58,012 | 4,784 | 8.2% |

- (1) Gross margin, EBITDA, Adjusted EBITDA and distributable cash flow are non-GAAP financial measures (see *How We Evaluate Our Operations* and *Non-GAAP Financial Measures*).
- (2) Includes the non-cash impact of commodity price movements on pipeline linefill.
- (3) General and administrative also includes compensation reimbursement to affiliates.
- (4) Represents Anadarko's non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest's non-controlling interest in Centrahoma.

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Gross margin

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the three months ended June 30, 2014 increased primarily due to higher production volumes. Overall gross margin percentages are lower for the three months ended June 30, 2014 due to an increase in POP contracts during the period, which reduced our commodity price risk, but negatively impacted our gross margin rate.

Oklahoma For the three months ended June 30, 2014, Oklahoma gross margins increased \$12.5 million compared to the prior year period.

Processed volumes on the SouthOK system for the three months ended June 30, 2014 increased from the prior year period volumes primarily due to the start-up of the Stonewall Plant on May 1, 2014 (see Recent Events), which allowed for the processing of gathered volumes that were previously offloaded to third parties.

Gathering and processing volumes on the WestOK system for the three months ended June 30, 2014 increased as a result of increased production on the gathering systems, which continue to be expanded to meet producer demand.

Transportation, processing and other fees for the three months ended June 30, 2014 increased due to an increase of processing fee revenue of \$2.9 million on the WestOK system related to the increased volumes gathered on the systems.

Texas For the three months ended June 30, 2014, Texas gross margins increased \$17.1 million compared to the prior year period.

WestTX system gathering and processing volumes for the three months ended June 30, 2014 increased compared to the prior year period due to continued increased volumes from Pioneer Natural Resources Company (NYSE: PXD) and others as a result of their continued drilling programs.

SouthTX system gathering and processing volumes per day for the three months ended June 30, 2014 were slightly lower than the prior year period.

Transportation, processing and other fees for the three months ended June 30, 2014 increased in our Texas segment primarily due to \$3.4 million in additional fee-based revenues on the SouthTX system acquired in the TEAK Acquisition on May 7, 2013 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3).

Expenses

Operating expenses, comprised primarily of plant operating expenses and transportation and compression expenses, for the three months ended June 30, 2014 increased mainly in our Texas segment due to \$2.0 million in additional

expenses from the SouthTX systems acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3).

General and administrative expense, including amounts reimbursed to affiliates, increased for the three months ended June 30, 2014 mainly due to a \$3.0 million increase in share-based compensation related to phantom units granted to employees (see Item 1: Notes to Consolidated Financial Statements

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(Unaudited) Note 15) and a \$2.2 million increase in salaries and wages partially due to the increase in the number of employees as a result of the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3), and continued growth in our other operating areas.

Other costs for the three months ended June 30, 2014 decreased mainly due to acquisition costs related to the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3) recorded in the prior year period.

Depreciation and amortization expense for the three months ended June 30, 2014 increased primarily in our Texas segment mainly due to additional expense related to assets acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3), and due to growth capital expenditures incurred subsequent to June 30, 2013.

Interest expense for the three months ended June 30, 2014 increased primarily due to \$2.1 million additional interest related to the 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes); offset by a \$1.8 million increase in capitalized interest expense. The increase in the interest on the 4.75% Senior Notes is due to its issuance in 2013 (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 13 Senior Notes). The increase in capitalized interest is due to increased capital expenditures over the same period last year.

Other income items

Derivative gain (loss), net for the three months ended June 30, 2014 had a \$24.0 million unfavorable mark-to-market gain (loss) variance compared to the prior year period primarily due to a decrease in forward prices during the prior year period resulting in mark-to-market gains on derivatives; and a \$9.5 million unfavorable variance in cash settlements in the current year period compared to the prior year period. While we utilize either quoted market prices or observable market data to calculate the fair value of natural gas and crude oil derivatives, valuations of NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGLs for similar geographic locations, and valuations of NGL options are based on forward price curves developed by third-party financial institutions. The use of unobservable market data for NGL fixed price swaps and NGL options has no impact on the settlement of these derivatives. However, a change in management's estimated fair values for these derivatives could impact net income, although it would have no impact on liquidity or capital resources (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 10 for further discussion of derivative instrument valuations). We recognized a \$1.2 million mark-to-market loss and a \$17.8 million mark-to-market gain on derivatives that were valued based upon unobservable inputs for the three months ended June 30, 2014 and 2013, respectively. 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 Item 3: Quantitative and Qualitative Disclosures About Market Risk.

Other income is primarily comprised of interest income on a note receivable from Anadarko in connection with our WestOK and WestTX systems. For the three months ended June 30, 2014, other income approximated the prior year period.

Non-cash linefill loss had a favorable variance for the three months ended June 30, 2014 compared to the prior year period primarily due to a mark-to-market loss on linefill volumes in the SouthTX system.

Equity income (loss) in joint ventures had an unfavorable variance for the three months ended June 30, 2014 primarily due to a \$4.8 million loss in the current period from the SouthTX equity method

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investments. The T2 LaSalle and T2 Eagle Ford joint ventures are structured to earn revenues equal to their operating costs, exclusive of depreciation expense. The loss primarily represents depreciation expense.

Income tax benefit for the three months ended June 30, 2014 represents the accrued income tax related to the income earned on APL Arkoma, Inc. The favorable variance compared to the prior period is due to APL Arkoma, Inc. incurring a larger taxable loss compared to the prior period.

Income attributable to non-controlling interests for the three months ended June 30, 2014 increased \$1.6 million in our Oklahoma segment primarily due to Anadarko's non-controlling interest in higher net income for the WestOK joint venture, and due to MarkWest's non-controlling interest in higher net income for the Centrahoma joint venture. The increase in net income of the WestOK joint venture was principally due to higher gross margins on the sale of commodities, resulting from higher volumes. The increase in net income of the Centrahoma joint venture was due to the start-up of the Stonewall Plant on May 1, 2014 (see Recent Events), which resulted in higher processed volumes during the period.

Income attributable to non-controlling interests for the three months ended June 30, 2014 increased \$0.6 million in our Texas segment primarily due to Anadarko's non-controlling interest in higher net income for the WestTX joint venture. The increase in net income of the WestTX joint venture was principally due to higher gross margins on the sale of commodities, resulting from higher volumes.

Preferred unit imputed dividend effect for the three months ended June 30, 2014 represents the accretion of the beneficial conversion discount of the Class D Preferred Units (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 5 Class D Preferred Units). The unfavorable variance compared to the prior period is due to the issuance of the Class D Preferred Units during May 2013.

Preferred unit dividends in-kind for the three months ended June 30, 2014 represent the distributions to the Class D Preferred Units, which have been declared (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 5 Class D Preferred Units). The unfavorable variance compared to the prior period is due to the issuance of the Class D Preferred Units during May 2013.

Preferred unit dividends for the three months ended June 30, 2014 represent the distributions to the Class E Preferred Units, attributable to the three month period ended June 30, 2014 (see Class E Preferred Units).

Non-GAAP financial data

Adjusted EBITDA had a favorable variance for the three months ended June 30, 2014 compared to the prior year period mainly due to the improved gross margin variance, as discussed above in Gross Margin, partially offset by higher operating expenses and general and administrative expenses as discussed above in Expenses.

Distributable cash flow had a favorable variance for the three months ended June 30, 2014 compared to the prior year period mainly due to the favorable Adjusted EBITDA variance, as discussed above, partially offset by higher interest expense as discussed above in Expenses and higher maintenance capital expenditures (see further discussion of capital expenditures under Capital Requirements).

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The following table and discussion is a summary of our consolidated results of operations for the six months ended June 30, 2014 and 2013 (in thousands):

| | Six Months Ended June 30, | | | |
|---|--------------------------------------|-------------|-----------------|---------------------------|
| | 2014 | 2013 | Variance | Percent Change |
| <i>Gross margin</i> ⁽¹⁾ | | | | |
| Natural gas and liquids sales | \$ 1,330,679 | \$ 875,078 | \$ 455,601 | 52.1% |
| Transportation, processing and other fees | 93,480 | 73,031 | 20,449 | 28.0% |
| Less: non-cash line fill gain (loss) ⁽²⁾ | 94 | (1,371) | 1,465 | 106.9% |
| Less: natural gas and liquids cost of sales | 1,156,353 | 749,756 | 406,597 | 54.2% |
| Gross margin | 267,712 | 199,724 | 67,988 | 34.0% |
| Gross margin % | 20.1% | 22.8% | | |
| <i>Expenses:</i> | | | | |
| Operating expenses | 52,111 | 46,629 | 5,482 | 11.8% |
| General and administrative ⁽³⁾ | 36,356 | 26,344 | 10,012 | 38.0% |
| Other costs | 17 | 18,900 | (18,883) | (99.9)% |
| Depreciation and amortization | 98,459 | 76,841 | 21,618 | 28.1% |
| Interest expense | 46,722 | 41,267 | 5,455 | 13.2% |
| Total expenses | 233,665 | 209,981 | 23,684 | 11.3% |
| <i>Other income items:</i> | | | | |
| Derivative gain (loss), net | (15,038) | 15,024 | (30,062) | (200.1)% |
| Other income, net | 4,839 | 5,718 | (879) | (15.4)% |
| Non-cash line fill gain (loss) ⁽²⁾ | 94 | (1,371) | 1,465 | 106.9% |
| Equity income (loss) in joint ventures | (5,753) | 1,568 | (7,321) | (466.9)% |
| Gain (loss) on asset disposition | 48,465 | (1,519) | 49,984 | 3,290.6% |
| Loss on early extinguishment of debt | | (26,601) | 26,601 | 100.0% |
| Income tax benefit | 896 | 37 | 859 | 2,321.6% |
| Income attributable to non-controlling interests ⁽⁴⁾ | (6,427) | (3,179) | (3,248) | (102.2)% |
| Preferred unit imputed dividend effect | (22,756) | (6,729) | (16,027) | (238.2)% |
| Preferred unit dividends in kind | (20,125) | (5,341) | (14,784) | (276.8)% |
| Preferred unit dividends | (3,015) | | (3,015) | (100.0)% |
| Net income (loss) attributable to common limited partners and General Partner | \$ 15,227 | \$ (32,650) | \$ 47,877 | 146.6% |
| <i>Non-GAAP financial data:</i> | | | | |
| EBITDA ⁽¹⁾ | \$ 211,835 | \$ 100,670 | \$ 111,165 | 110.4% |
| Adjusted EBITDA ⁽¹⁾ | 183,691 | 154,018 | 29,673 | 19.3% |
| Distributable cash flow ⁽¹⁾ | 123,631 | 101,487 | 22,144 | 21.8% |

- (1) Gross Margin, EBITDA, Adjusted EBITDA and Distributable cash flow are non-GAAP financial measures (see [How We Evaluate Our Operations](#) and [Non-GAAP Financial Measures](#)).
- (2) Includes the non-cash impact of commodity price movements on pipeline linefill.
- (3) General and administrative also includes any compensation reimbursement to affiliates.
- (4) Represents Anadarko's non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest's non-controlling interest in the operating results of Centrahoma.

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Gross margin

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the six months ended June 30, 2014 increased primarily due to higher production volumes. Overall gross margin percentages are lower for the six months ended June 30, 2014 due to the increase in natural gas prices, which increased at a higher rate than NGL prices, negatively impacting the gross margin rate achieved on Keep-Whole contracts.

Oklahoma For the six months ended June 30, 2014, Oklahoma gross margins increased \$27.4 million compared to the prior year period.

Processed volumes on the SouthOK system for the six months ended June 30, 2014 increased from the prior year period volumes primarily due to the start-up of the Stonewall Plant on May 1, 2014 (see Recent Events), which allowed for the processing of gathered volumes that were previously offloaded to third parties.

Gathering and processing volumes on the WestOK system for the six months ended June 30, 2014 increased as a result of increased production on the gathering systems, which continue to be expanded to meet producer demand.

Transportation, processing and other fees increased due to an increase of processing fee revenue of \$4.4 million on the WestOK system related to the increased volumes gathered on the systems

Texas For the six months ended June 30, 2014, Texas gross margins increased \$42.4 million compared to the prior year period.

WestTX system gathering and processing volumes for the six months ended June 30, 2014 increased compared to the prior year period due to continued increased volumes from Pioneer Natural Resources Company (NYSE: PXD) and others as a result of their continued drilling programs, and due to the April 2013 start-up of the Driver plant during the prior year period.

Gross margins also increased compared to the prior year period due to the acquisition of the SouthTX system as part of the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3) during the prior year period.

Transportation, processing and other fees for the six months ended June 30, 2014 increased primarily due to \$10.8 million in additional fee-based revenues on the SouthTX system acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3).

Expenses

Operating expenses, comprised primarily of plant operating expenses and transportation and compression expenses, for the six months ended June 30, 2014 increased mainly in our Texas segment due to \$5.1 million in additional

expenses from the SouthTX systems acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3).

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General and administrative expense, including amounts reimbursed to affiliates, increased for the six months ended June 30, 2014 mainly due to a \$5.1 million increase in share-based compensation related to phantom units granted to employees (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 15) and a \$4.3 million increase in salaries and wages partially due to the increase in the number of employees as a result of the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3), and continued growth in our other operating areas.

Other costs for the six months ended June 30, 2014 decreased mainly due to acquisition costs related to the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3) recorded in the prior year period.

Depreciation and amortization expense for the six months ended June 30, 2014 increased primarily in our Texas segment mainly due to \$18.3 million additional expense related to assets acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3), and due to growth capital expenditures incurred subsequent to June 30, 2013.

Interest expense for the six months ended June 30, 2014 increased primarily due to \$6.9 million additional interest related to the 4.75% Senior Notes and \$4.2 million of additional interest related to the 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes); offset by \$4.2 million reduced interest expense on the 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes) and a \$2.2 million increase in capitalized interest expense. The increase in the interest on the 4.75% Senior Notes and the 5.875% Senior Notes is due to their issuance in 2013 (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 13 Senior Notes). The decrease in the interest for the 8.75% Senior Notes is due to their redemption in February 2013 (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 13 Senior Notes). The increase in capitalized interest is due to increased capital expenditures over the same period last year.

Other income items

Derivative income (loss), net for the six months ended June 30, 2014 had a \$9.1 million unfavorable mark-to-market gain (loss) variance compared to the prior year period primarily due to a decrease in forward prices during the prior year period resulting in mark-to-market gains and a \$20.9 million unfavorable cash settlements in the current year period compared to the prior year period. We recognized a \$2.3 million and a \$15.4 million mark-to-market loss on derivatives that were valued based upon unobservable inputs for the six months ended June 30, 2014 and 2013, respectively.

Other income is primarily comprised of interest income on a note receivable from Anadarko in connection with acquiring our WestOK and WestTX systems. For the six months ended June 30, 2014, other income approximated the prior year period.

Non-cash linefill loss had a favorable variance for the six months ended June 30, 2014 compared to the prior year period primarily due to a loss on additional linefill volumes at SouthTX that are valued at mark-to-market due to an increase in the forward price curve.

Equity income (loss) in joint ventures decreased for the six months ended June 30, 2014 primarily due to a \$8.4 million loss in the current period from the SouthTX equity method investments. The T2 LaSalle and T2 Eagle Ford joint ventures are structured to earn revenues equal to their operating costs, exclusive of depreciation expense. The loss primarily represents depreciation expense.

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Income tax benefit for the six months ended June 30, 2014 represents the accrued income tax related to the income earned on APL Arkoma, Inc. The favorable variance compared to the prior period is due to APL Arkoma, Inc. incurring a larger taxable loss compared to the prior period.

Income attributable to non-controlling interests for the six months ended June 30, 2014 increased \$2.1 million in our Oklahoma segment primarily due to Anadarko's non-controlling interest in higher net income for the WestOK joint venture and MarkWest's non-controlling interest in higher net income for the Centrahoma joint venture. The increase in net income in the WestOK joint venture was principally due to higher gross margins on the sale of commodities, resulting from higher volumes. The increase in net income of the Centrahoma joint venture was due to the start-up of the Stonewall Plant on May 1, 2014 (see Recent Events), which resulted in higher processed volumes during the period.

Income attributable to non-controlling interests for the six months ended June 30, 2014 increased \$1.2 million in our Texas segment primarily due to Anadarko's non-controlling interest in higher net income for the WestTX joint venture. The increase in net income in the WestTX joint venture was principally due to higher gross margins on the sale of commodities, resulting from higher volumes.

Preferred unit imputed dividend effect for the six months ended June 30, 2014 represents the accretion of the beneficial conversion discount of the Class D Preferred Units (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 5 Class D Preferred Units). The unfavorable variance compared to the prior period is due to the issuance of the Class D Preferred Units during May 2013.

Preferred unit dividends in-kind for the six months ended June 30, 2013 represent the distributions to the Class D Preferred Units, which have been declared (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 5 Class D Preferred Units). The unfavorable variance compared to the prior period is due to the issuance of the Class D Preferred Units during May 2013.

Preferred unit dividends for the six months ended June 30, 2014 represent the distributions to the Class E Preferred Units, attributable to the six month period ended June 30, 2014 (see Class E Preferred Units).

Non-GAAP financial data

Adjusted EBITDA had a favorable variance for the six months ended June 30, 2014 compared to the prior year period mainly due to the improved gross margin variance, as discussed above in Gross Margin, partially offset by higher operating expenses and general and administrative expenses as discussed above in Expenses.

Distributable cash flow had a favorable variance for the six months ended June 30, 2014 compared to the prior year period mainly due to the favorable Adjusted EBITDA variance, as discussed above, partially offset by higher interest expense as discussed above in Expenses and higher maintenance capital expenditures (see further discussion of capital expenditures under Capital Requirements).

Table of Contents**Liquidity and Capital Resources***General*

At June 30, 2014, we had \$100.0 million outstanding borrowings under our \$600.0 million senior secured revolving credit facility and \$3.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with \$496.9 million of remaining committed capacity under the revolving credit facility, (see [Revolving Credit Facility](#)). We were in compliance with the credit facility's covenants at June 30, 2014. We had a working capital deficit of \$114.0 million at June 30, 2014 compared with a \$78.4 million working capital deficit at December 31, 2013. We believe we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash flows. We may need to supplement our cash generation with proceeds from financing activities, including borrowings under our revolving credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

Cash Flows Six Months Ended June, 2014 Compared to Six Months Ended June 30, 2013

The following table details the cash flow changes between the six months ended June 30, 2014 and 2013 (in thousands):

| | Six Months Ended | | Variance | Percent Change |
|--|-------------------------|------------------|--------------------|-----------------------|
| | 2014 | 2013 | | |
| Net cash provided by (used in): | | | | |
| Operating activities | \$ 139,909 | \$ 71,721 | \$ 68,188 | 95.1% |
| Investing activities | (150,412) | (1,216,244) | 1,065,832 | 87.6% |
| Financing activities | 9,663 | 1,162,206 | (1,152,543) | (99.2)% |
| Net change in cash and cash equivalents | \$ (840) | \$ 17,683 | \$ (18,523) | |

Net cash provided by operating activities for the six months ended June 30, 2014 increased compared to the prior year period primarily due to a \$53.4 million increase in net earnings from continuing operations excluding non-cash charges. The increase is primarily due to increased gross margins from the sale of natural gas and NGLs offset by an increase in operating expense, general and administrative expense and interest expense (see [Results of Operations](#)).

Net cash used in investing activities for the six months ended June 30, 2014 decreased compared to the prior year period mainly due to the \$1.0 billion TEAK Acquisition (see [Item 1. Notes to Consolidated Financial Statements \(Unaudited\) Note 3](#)) in the prior year period and due to the receipt of \$132.7 million in net proceeds from the sale of WTLPG (see [Recent Events](#)), partially offset by an increase in capital expenditures in the current year period compared to the prior year period (see further discussion of capital expenditures under [Capital Requirements](#)).

Net cash provided by financing activities for the six months ended June 30, 2014 decreased compared to the prior year period mainly due to (i) \$637.3 million provided by the issuance of the 5.875% Senior Notes in the prior year period; (ii) \$397.7 million provided by the issuance of Class D Preferred Units in the prior year period; (iii) \$391.2 million provided by the issuance of the 4.75% Senior Notes in the prior year period; and (iv) \$388.4 million provided by the

April 2013 common unit issuance of 11,845,000 common units in the prior year period. These decreases were partially offset by (i) the \$391.4 million redemption of the 8.75% Senior Notes, including the cost of early retirement of debt in the prior

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year period; (ii) a \$213.0 million net decrease in the prior year period to outstanding borrowings on the revolving credit facility; and (iii) \$122.3 million provided by the issuance of the Class E Preferred Units in the current period (see Class E Preferreds). The gross amount of borrowings and repayments under the revolving credit facility included within net cash provided by (used in) financing activities in the consolidated combined statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of (i) cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under the revolving credit facility, and (ii) payments, which generally occur throughout the period and increase borrowings under the revolving credit facility, which is generally common practice for the industry.

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):

| | Three Months Ended | | Six Months Ended | |
|----------------------------------|---------------------------|-------------------|-------------------------|-------------------|
| | June 30, | | June 30, | |
| | 2014 | 2013 | 2014 | 2013 |
| Maintenance capital expenditures | \$ 5,555 | \$ 3,848 | \$ 10,880 | \$ 7,703 |
| Expansion capital expenditures | 146,693 | 103,345 | 269,699 | 208,006 |
| Total | \$ 152,248 | \$ 107,193 | \$ 280,579 | \$ 215,709 |

The increase in maintenance capital expenditures for the three and six months ended June 30, 2014 when compared with the corresponding prior year period was due to fluctuations in the timing of scheduled maintenance activity.

Expansion capital expenditures increased for the three and six months ended June 30, 2014 primarily due to construction costs for (i) the Stonewall plant within SouthOK, which was placed in service May 1, 2014 (see Recent Events), (ii) the Silver Oak II plant within SouthTX placed in service in June 2014, (iii) the Edward plant within WestTX scheduled to be placed in service during the third quarter of 2014; and (iv) the construction of the Velma to Arkoma connection within SouthOK scheduled to be completed during third quarter 2014. As of June 30, 2014, we had approved additional expenditures of approximately \$398.2 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately \$182.4 million in purchase commitments had been made. We expect to fund these projects through operating cash flows and borrowings under our revolving credit facility.

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Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash, for each calendar quarter, to our common unitholders and our General Partner within 45 days following the end of such calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance in May 2013, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of our General Partner.

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 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 2.0% 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 limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 2.0% of the aggregate amount of cash being distributed. Our General Partner, holder of all our incentive distribution rights, has agreed to allocate up to \$3.75 million of its incentive distribution rights per quarter back to us after the General Partner receives the initial \$7.0 million of incentive distribution rights per quarter. Incentive distributions of \$5.0 million and \$3.0 million were paid during the three months ended June 30, 2014 and 2013, respectively, and \$9.9 million and \$5.3 million were paid during the six months ended June 30, 2014 and 2013, respectively.

Common Equity Offerings

On May 12, 2014, we entered into the 2014 EDA with our Sales Agents (see Recent Events). Pursuant to the 2014 EDA, we may offer and sell from time to time through our Sales Agents, common units having an aggregate value up to \$250.0 million. Sales are at market prices prevailing at the time of the sale. During the three months ended June 30, 2014 and 2013, we issued 1,462,187 and 642,495 common units, respectively, under the 2014 EDA and an Equity Distribution Agreement entered into in November 2012 (the 2012 EDA and together with the 2014 EDA, the EDAs) for net proceeds of \$47.4 million and \$24.5 million, respectively, net of \$0.5 million and \$0.5 million, respectively, in commissions paid to the Sales Agents. During the six months ended June 30, 2014 and 2013, we issued 1,462,187 and 1,090,280 common units, respectively, under the EDAs for net proceeds of \$47.4 million and \$38.9 million, respectively, net of \$0.5 million and \$0.8 million, respectively, in commissions paid to the Sales Agents. We also received capital contributions from the General Partner of \$1.0 million and \$0.5 million, respectively, during the three months ended June 30, 2014 and 2013, and \$1.0 million and \$0.8 million, respectively, during the six months ended June 30, 2014 and 2013, to maintain its 2.0% general partner interest in the Partnership. The net proceeds from the common unit offerings were utilized for general partnership purposes. As of June 30, 2014, we had \$202.0 million remaining dollar capacity under the 2014 EDA (see Item 1. Notes to Consolidate Financial Statements (Unaudited) Note 5).

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Class E Preferred Units

On March 17, 2014, we issued 5,060,000 of our Class E Preferred Units to the public at an offering price of \$25.00 per Class E Preferred Unit. We received \$122.3 million in net proceeds, which were used to pay down the revolving credit facility. We will make cumulative cash distributions on the Class E Preferred Units from the date of original issue. The cash distributions will be payable quarterly in arrears on January 15, April 15, July 15, and October 15 of each year, when, and if, declared by the board of directors. The initial distribution on the Class E Preferred Units was paid on July 15, 2014 in an amount equal to \$0.67604 per unit, or approximately \$3.4 million. Going forward, we will pay cumulative distributions in cash on the Class E Preferred Units on a quarterly basis at a rate of \$0.515625 per unit, or 8.25% per year (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Class E Preferred Units).

Off Balance Sheet Arrangements

As of June 30, 2014, our off balance sheet arrangements include our letters of credit, issued under the provisions of our revolving credit facility, totaling \$3.1 million. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety, and (iii) counterparty support.

We have certain long-term unconditional purchase obligations and commitments, primarily throughput contracts. These agreements provide transportation services to be used in the ordinary course of our operations.

Revolving Credit Facility

At June 30, 2014, we had a \$600.0 million senior secured revolving credit facility with a syndicate of banks, which matures in May 2017. The weighted average interest rate for borrowings on the revolving credit facility, at June 30, 2014, was 3.2%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$3.1 million was outstanding at June 30, 2014. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

On March 11, 2014, we entered into an amendment to the credit agreement governing our revolving credit facility, which among other changes, adjusted the Acquisition Period for the Consolidated Funded Debt Ratio, and permitted the payment of cash distributions on the Class E Preferred Units (see Class E Preferred Units).

The events that constitute an event of default for our revolving credit facility include payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. As of June 30, 2014, we were in compliance with all covenants under the revolving credit facility.

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Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP 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 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 subject to such estimates and assumptions include revenue and expense accruals, 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.

There have been no material changes in the methodology applied by management for critical accounting policies and estimates from those disclosed in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2013.

Recently Adopted Accounting Standards

See Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 2 Recently Adopted Accounting Standards for information regarding recently adopted accounting pronouncements.

Recently Issued Accounting Standards

See Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 2 Recently Issued Accounting Standards for information regarding recently issued accounting pronouncements.

ITEM 3. 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 our market risk sensitive instruments were entered into for purposes other than trading.

General

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative instruments.

The information about commodity price risk and interest rate risk for the three and six months ended June 30, 2014 does not differ materially from that discussed in Item 7A. Quantitative and Qualitative Disclosures about Market Risk of our Annual Report on Form 10-K for the year ended December 31, 2013.

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ITEM 4. 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 June 30, 2014, our disclosure controls and procedures were effective at the reasonable assurance level.

There have been no material changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents**PART II. OTHER INFORMATION****ITEM 1A. RISK FACTORS**

There have been no material changes in our risk factors from those disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2013.

ITEM 6. EXHIBITS**Exhibit**

| No. | Description |
|------------|--|
| 1.1 | Equity Distribution Agreement, dated May 12, 2014, among Atlas Pipeline Partners, L.P. and Citigroup Global Markets Inc., Wells Fargo Securities, LLC and MLV & Co. LLC ⁽³⁸⁾ |
| 2.1 | Purchase and Sale agreement, dated as of April 16, 2013, among TEAK Midstream Holdings, LLC, TEAK Midstream, L.L.C. and Atlas Pipeline Mid-Continent Holdings, LLC. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request ⁽³³⁾ |
| 3.1(a) | Certificate of Limited Partnership ⁽¹⁾ |
| 3.1(b) | Amendment to Certificate of Limited Partnership ⁽¹²⁾ |
| 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 ⁽⁵⁾ |
| 3.2(e) | Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership ⁽⁶⁾ |
| 3.2(f) | Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership ⁽⁸⁾ |
| 3.2(g) | Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership ⁽⁹⁾ |
| 3.2(h) | Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership ⁽¹⁴⁾ |
| 3.2(i) | Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership ⁽¹⁵⁾ |
| 3.2(j) | Amendment No. 9 to Second Amended and Restated Agreement of Limited Partnership ⁽¹²⁾ |
| 3.2(k) | Amendment No. 10 to Second Amended and Restated Agreement of Limited Partnership ⁽³⁰⁾ |
| 3.2(j) | Amendment No. 11 to Second Amended and Restated Agreement of Limited Partnership ⁽³⁶⁾ |
| 4.1 | Common unit certificate (attached as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership) ⁽²⁾ |
| 4.2(a) | 6 5/8% Senior Notes Indenture dated September 28, 2012 ⁽²⁶⁾ |

- 4.2(b) Supplemental Indenture dated as of December 20, 2012⁽³²⁾
- 4.3(a) 5 7/8% Senior Notes Indenture dated as of February 11, 2013⁽¹⁰⁾
- 4.3(b) Supplemental Indenture dated as of February 11, 2013⁽¹⁰⁾
- 4.4 4 3/4% Senior Notes Indenture dated May 10, 2013⁽⁷⁾
- 4.5(a) Certificate of Designation of Class D Convertible Preferred Units⁽³⁰⁾
- 4.5(b) Certificate of Amendment to Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional, and Other Special Rights and Qualifications, Limitations and Restrictions Thereof, dated as of March 12, 2014⁽³⁶⁾
- 4.6 Registration Rights Agreement, dated May 16, 2012, between Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein⁽²⁵⁾
- 4.7 Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional, and Other Special Rights of Preferred Units and Qualifications, Limitations and Restrictions Thereof, dated as of March 17, 2014⁽³⁶⁾

Table of Contents**Exhibit**

| No. | Description |
|------------|---|
| 10.1(a) | Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽¹⁾ |
| 10.1(b) | Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽¹⁴⁾ |
| 10.1(c) | Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽¹²⁾ |
| 10.1(d) | Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽³⁶⁾ |
| 10.2 | Second Amended and Restated Limited Liability Company Agreement of Atlas Pipeline Partners GP, LLC. ⁽¹⁹⁾ |
| 10.3(a) | Amended and Restated Credit Agreement dated July 27, 2007, amended and restated as of December 22, 2010, by and among Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the several guarantors and lenders hereto ⁽¹⁶⁾ |
| 10.3(b) | Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011 ⁽²²⁾ |
| 10.3(c) | Incremental Joinder Agreement to the Amended and Restated Credit Agreement dated as of July 8, 2011 ⁽²³⁾ |
| 10.3(d) | Amendment No. 2 to the Amended and Restated Credit Agreement dated as of May 31, 2012 ⁽²⁷⁾ |
| 10.3(e) | Amendment No. 3 to the Amended and Restated Credit Agreement ⁽³¹⁾ |
| 10.3(f) | Amendment No. 4 to the Amended and Restated Credit Agreement ⁽³⁴⁾ |
| 10.3(g) | Amendment No. 5 to the Amended and Restated Credit Agreement |
| 10.3(h) | Amendment No. 6 to the Amended and Restated Credit Agreement ⁽³⁷⁾ |
| 10.4 | Long-Term Incentive Plan ⁽³⁵⁾ |
| 10.5 | Amended and Restated 2010 Long-Term Incentive Plan ⁽²²⁾ |
| 10.6 | Form of Grant of Phantom Units in Exchange for Bonus Units ⁽¹⁷⁾ |
| 10.7 | Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter ⁽¹⁸⁾ |
| 10.8 | Form of 2004 Long-Term Incentive Plan Phantom Unit Grant Letter ⁽²⁸⁾ |
| 10.9 | Form of Grant of Phantom Units to Non-Employee Managers ⁽¹¹⁾ |
| 10.10 | Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010 ⁽¹³⁾ |
| 10.11 | Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010 ⁽²⁰⁾ |
| 10.12 | Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010 ⁽²⁰⁾ |
| 10.13 | Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011 ⁽²⁴⁾ |
| 10.14 | |

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| | |
|-------|---|
| | Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011 ⁽²⁴⁾ |
| 10.15 | Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011 ⁽²¹⁾ |
| 10.16 | Employment Agreement between Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Patrick J. McDonie dated as of July 3, 2012 ⁽²⁵⁾ |
| 10.17 | Registration Rights Agreement, dated February 11, 2013, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein ⁽¹⁰⁾ |
| 10.18 | Registration Rights Agreement, dated May 7, 2013 by and among Atlas Pipeline Partners, L.P. and the purchasers named therein ⁽³⁰⁾ |
| 12.1 | Statement of Computation of Ratio of Earnings to Fixed Charges |
| 31.1 | Rule 13a-14(a)/15d-14(a) Certification |

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| Exhibit No. | Description |
|--------------------|---|
| 31.2 | Rule 13a-14(a)/15d-14(a) Certification |
| 32.1 | Section 1350 Certification |
| 32.2 | Section 1350 Certification |
| 101.INS | XBRL Instance Document ⁽³⁹⁾ |
| 101.SCH | XBRL Schema Document ⁽³⁹⁾ |
| 101.CAL | XBRL Calculation Linkbase Document ⁽³⁹⁾ |
| 101.LAB | XBRL Label Linkbase Document ⁽³⁹⁾ |
| 101.PRE | XBRL Presentation Linkbase Document ⁽³⁹⁾ |
| 101.DEF | XBRL Definition Linkbase Document ⁽³⁹⁾ |

- (1) Filed previously as an exhibit to registration statement on Form S-1 (Registration No. 333-85193).
- (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 8, 2008.
- (6) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
- (7) Previously filed as an exhibit to current report on Form 8-K on May 13, 2013.
- (8) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
- (9) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
- (10) Previously filed as an exhibit to current report on Form 8-K filed on February 12, 2013.
- (11) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2010.
- (12) Previously filed as an exhibit to current report on Form 8-K on December 13, 2011.
- (13) Previously filed as an exhibit to current report on Form 8-K on November 12, 2010.
- (14) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
- (15) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
- (16) Previously filed as an exhibit to current report on Form 8-K on December 23, 2010.
- (17) Previously filed as an exhibit to current report on Form 8-K filed on June 17, 2010.
- (18) Previously filed as an exhibit to current report on Form 8-K filed on June 23, 2010.
- (19) Previously filed as an exhibit to current report on Form 8-K on October 29, 2013.
- (20) Previously filed as an exhibit to Atlas Energy, Inc.'s current report on Form 8-K filed on November 12, 2010.
- (21) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2011.
- (22) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2011.
- (23) Previously filed as an exhibit to current report on Form 8-K filed on July 11, 2011.
- (24) Previously filed as an exhibit to Atlas Energy, L.P.'s quarterly report on Form 10-Q for the quarter ended March 31, 2011.
- (25) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2012.
- (26) Previously filed as an exhibit to current report on Form 8-K filed on January 30, 2013.
- (27) Previously filed as an exhibit to current report on Form 8-K filed on May 31, 2012.
- (28) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2012.
- (29) Intentionally omitted.
- (30) Previously filed as an exhibit to current report on Form 8-K filed on May 8, 2013.

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- (31) Previously filed as an exhibit to current report on Form 8-K filed on December 13, 2012.
- (32) Previously filed as an exhibit to current report on Form 8-K filed on December 26, 2012.
- (33) Previously filed as an exhibit to current report on Form 8-K filed on April 17, 2013.
- (34) Previously filed as an exhibit to current report on Form 8-K filed on April 23, 2013.
- (35) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2009.
- (36) Previously filed as an exhibit to current report on Form 8-K filed on March 17, 2014.
- (37) Previously filed as an exhibit to current report on Form 8-K filed on March 11, 2014.
- (38) Previously filed as an exhibit to current report on Form 8-K filed on May 13, 2014.
- (39) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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SIGNATURES

Pursuant to the requirements of 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

Date: August 6, 2014

By: /s/ EUGENE N. DUBAY
Eugene N. Dubay
Chief Executive Officer, President and Managing
Board Member of the General Partner

Date: August 6, 2014

By: /s/ ROBERT W. KARLOVICH, III
Robert W. Karlovich, III
Chief Financial Officer and Chief Accounting
Officer of the General Partner