Southcross Energy Partners, L.P.
Form 10-Q
November 06, 2015
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2015

OR

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

For the transition period from to

Commission File Number: 001-35719

Southcross Energy Partners, L.P.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| DELAWARE<br>(State or other jurisdiction of<br>incorporation or organization) | 45-5045230<br>(I.R.S. Employer<br>Identification No.) |
| 1717 Main Street, Suite 5200<br>Dallas, TX<br>(Address of principal executive offices) | 75201<br><br>(Zip Code) |

(214) 979-3700
(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 ý No o

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

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. (Check one):

| | |
|---|---|
| Large accelerated filer o | Accelerated filer x |
| Non-accelerated filer o<br>(Do not check if a smaller reporting company) | Smaller reporting company o |

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

Indicate the number of units outstanding of the issuer’s classes of common units, subordinated units and Class B Convertible Units, as of the latest practicable date:

As of November 3, 2015, the registrant has 28,420,619 common units outstanding, 12,213,713 subordinated units outstanding and 15,684,512 Class B Convertible Units outstanding.  Our common units trade on the NYSE under the symbol “SXE.”

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Commonly Used Terms

As generally used in the energy industry and in this Quarterly Report on Form 10-Q, the following terms have the following meanings:

/d: Per day

/gal: Per gallon

Bbls: Barrels

Condensate: Hydrocarbons that are produced from natural gas reservoirs but remain liquid at normal temperature and pressure

MMBtu: One million British thermal units

MMcf: One million cubic feet

NGLs: Natural gas liquids, which consist primarily of ethane, propane, isobutane, normal butane, natural gasoline and stabilized condensate

Residue gas: Pipeline quality natural gas remaining after natural gas is processed and NGLs and other matters are removed

Rich gas: Natural gas that is high in NGL content

Throughput: The volume of natural gas and NGLs transported or passing through a pipeline, plant, terminal or other facility

Y-grade: Commingled mix of NGL components extracted via natural gas processing normally consisting of ethane, propane, isobutane, normal butane and natural gasoline

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FORWARD-LOOKING INFORMATION

Investors are cautioned that certain statements contained in this report as well as in periodic press releases and oral statements made by our management team during our presentations are “forward-looking” statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “wou and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us or our subsidiaries, are also forward-looking statements. These forward-looking statements involve external risks and uncertainties, including, but not limited to, those described under the section entitled “Risk Factors” included in our 2014 Annual Report on Form 10-K as updated by the Current Report on Form 8-K dated August 20, 2015.

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond the control of our management team. All forward-looking statements in this report and subsequent written and oral forward-looking statements attributable to us, or to persons acting on our behalf, are expressly qualified in their entirety by these risks and uncertainties. These risks and uncertainties include, among others:

- the volatility of natural gas, crude oil and NGL prices and the price and demand of products derived from these commodities, particularly in the depressed energy price environment that began in the second half of 2014, which has the potential for further deterioration and may result in a material reduction in exploration, development and production of crude oil or natural gas;
- competitive conditions in our industry and the extent and success of producers increasing production or replacing declining production and our success in obtaining new sources of supply;
- industry conditions and supply of pipelines, processing and fractionation capacity relative to available natural gas from producers;
- our dependence upon a relatively limited number of customers for a significant portion of our revenues;
- actions taken or inactions or non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- our ability to recover NGLs effectively at a rate equal to or greater than our contracted rates with customers;
- our ability to produce and market NGLs at the anticipated differential to NGL index pricing;
- our access to markets enabling us to match pricing indices for purchases and sales of natural gas and NGLs;
- our ability to complete projects within budget and on schedule, including but not limited to, timely receipt of necessary government approvals and permits, our ability to control the costs of construction and other factors that may impact projects;
- our ability to consummate acquisitions, successfully integrate the acquired businesses and realize anticipated cost savings and other synergies from any acquisitions, including with respect to our acquisition of certain gathering and processing assets from TexStar Midstream Services, LP in August 2014 and other assets acquired in May 2015;
- our ability to manage, over time, changing exposure to commodity price risk;
- the effectiveness of our hedging activities or our decisions not to undertake hedging activities;
- our access to financing and ability to remain in compliance with our financial covenants, and the potential for lack of access to debt and equity capital markets if the depressed energy price environment that began in the second half of 2014 continues;
- our ability to generate sufficient operating cash flow to fund our quarterly distributions;
- the effects of downtime associated with our assets or the assets of third parties interconnected with our systems;
- operating hazards, fires, natural disasters, weather-related delays, casualty losses and other matters beyond our control;

- the failure of our processing, fractionation and treating plants to perform as expected, including outages for unscheduled maintenance or repair;
- the effects of laws and governmental regulations and policies;
- the effects of existing and future litigation;
- changes in general economic conditions; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our filings with the U.S. Securities and Exchange Commission.

Developments in any of these areas could cause actual results to differ materially from those anticipated or projected, affect our ability to maintain distribution levels and/or access necessary financial markets or cause a significant reduction in the market price of our common units.

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The foregoing list of risks and uncertainties may not contain all of the risks and uncertainties that could affect us. In addition, in light of these risks and uncertainties, the matters referred to in the forward-looking statements contained in this report may not, in fact, occur. Accordingly, undue reliance should not be placed on these statements. We undertake no obligation to update publicly or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law.

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PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except for unit data)
(Unaudited)

| | September 30, 2015 | December 31, 2014 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $1,651 | $1,649 |
| Trade accounts receivable | 43,765 | 74,086 |
| Accounts receivable - affiliates | 32,662 | 11,325 |
| Prepaid expenses | 4,238 | 3,073 |
| Other current assets | 3,174 | 1,813 |
| Total current assets | 85,490 | 91,946 |
| | | |
| Property, plant and equipment, net | 1,074,664 | 1,058,570 |
| Intangible assets, net | 1,469 | 1,511 |
| Investments in joint ventures | 139,973 | 147,098 |
| Other assets | 27,159 | 17,189 |
| Total assets | $1,328,755 | $1,316,314 |
| | | |
| LIABILITIES AND PARTNERS' CAPITAL | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $83,701 | $116,842 |
| Accounts payable - affiliates | 5,258 | 12,856 |
| Current portion of long-term debt | 4,500 | 4,500 |
| Other current liabilities | 12,238 | 12,773 |
| Total current liabilities | 105,697 | 146,971 |
| | | |
| Long-term debt | 573,007 | 471,129 |
| Other non-current liabilities | 3,785 | 1,110 |
| Total liabilities | 682,489 | 619,210 |
| | | |
| Commitments and contingencies (Note 7) | | |
| | | |
| Partners' capital: | | |
| Common units (28,418,156 and 23,800,943 units outstanding as of September 30, 2015 and December 31, 2014, respectively) | 287,761 | 259,735 |
| Class B Convertible units (15,684,512 and 14,889,078 units issued and outstanding as of September 30, 2015 and December 31, 2014, respectively) | 304,930 | 298,833 |
| Subordinated units (12,213,713 units issued and outstanding as of September 30, 2015 and December 31, 2014) | 41,291 | 48,831 |
| General partner interest | 12,284 | 12,385 |
| Southcross Holdings' equity in contributed subsidiaries | — | 77,320 |
| Total partners' capital | 646,266 | 697,104 |

| | | |
|---|---|---|
| Total liabilities and partners' capital | $1,328,755 | $1,316,314 |

See accompanying notes.

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SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except for per unit data)
(Unaudited)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Revenues: | | | | |
| Revenues | $147,114 | $206,388 | $471,735 | $615,042 |
| Revenues - affiliates | 32,455 | 6,290 | 60,993 | 6,290 |
| Total revenues | 179,569 | 212,678 | 532,728 | 621,332 |
| Expenses: | | | | |
| Cost of natural gas and liquids sold | 133,401 | 180,562 | 399,111 | 535,791 |
| Operations and maintenance | 19,139 | 18,097 | 61,528 | 40,702 |
| Depreciation and amortization | 17,853 | 12,701 | 52,456 | 30,207 |
| General and administrative | 6,803 | 15,085 | 23,612 | 27,881 |
| Impairment of assets | — | 1,556 | 193 | 1,556 |
| Loss (gain) on sale of assets, net | (33) | 334 | 146 | 292 |
| Total expenses | 177,163 | 228,335 | 537,046 | 636,429 |
| Income (loss) from operations | 2,406 | (15,657) | (4,318) | (15,097) |
| Other expense: | | | | |
| Equity in losses of joint venture investments | (3,567) | (3,308) | (10,722) | (3,308) |
| Interest expense | (8,688) | (4,596) | (24,087) | (9,340) |
| Loss on extinguishment of debt | — | (2,316) | — | (2,316) |
| Other expense | — | (86) | — | (86) |
| Total other expense | (12,255) | (10,306) | (34,809) | (15,050) |
| Loss before income tax benefit (expense) | (9,849) | (25,963) | (39,127) | (30,147) |
| Income tax benefit (expense) | 190 | (69) | 113 | (133) |
| Net loss | $(9,659) | $(26,032) | $(39,014) | $(30,280) |
| Series A Preferred unit fair value adjustment | — | 424 | — | (4,596) |
| Series A Preferred unit in-kind distribution | — | — | — | (534) |
| General partner unit in-kind distribution | (28) | (112) | (165) | (123) |
| Net loss attributable to Holdings | — | (1,254) | (4,258) | (1,254) |
| Net loss attributable to partners | $(9,687) | $(24,466) | $(34,921) | $(34,279) |
| Earnings per unit and distributions declared | | | | |
| Net loss allocated to limited partner common units | $(4,799) | $(11,156) | $(16,711) | $(19,084) |
| Weighted average number of limited partner common units outstanding | 28,372 | 22,926 | 26,234 | 20,911 |
| Basic and diluted loss per common unit | $(0.17) | $(0.49) | $(0.64) | $(0.91) |
| Net loss allocated to limited partner subordinated units | $(2,065) | $(6,009) | $(7,777) | $(7,795) |
| Weighted average number of limited partner subordinated units outstanding | 12,214 | 12,214 | 12,214 | 12,214 |
| Basic and diluted loss per subordinated unit | $(0.17) | $(0.49) | $(0.64) | $(0.64) |

| | | | | |
|---|---|---|---|---|
| Distributions declared per common unit | $0.40 | $0.40 | $1.20 | $1.20 |

See accompanying notes.

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SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(In thousands)
(Unaudited)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Net loss | $(9,659) | $(26,032) | $(39,014) | $(30,280) |
| Other comprehensive income (loss): | | | | |
| Hedging losses reclassified to earnings and recognized in interest expense | — | — | — | 221 |
| Adjustment in fair value of derivatives | — | — | — | (11) |
| Total other comprehensive income | — | — | — | 210 |
| Comprehensive loss | $(9,659) | $(26,032) | $(39,014) | $(30,070) |

See accompanying notes.

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SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2015 | 2014 |
| Cash flows from operating activities: | | |
| Net loss | $(39,014) | $(30,280) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depreciation and amortization | 52,456 | 30,207 |
| Unit-based compensation | 3,513 | 10,837 |
| Amortization of deferred financing costs | 2,615 | 3,596 |
| Loss on sale of assets, net | 146 | 292 |
| Unrealized loss on financial instruments | 289 | 539 |
| Equity in losses of joint venture investments | 10,722 | 3,308 |
| Distribution from joint venture investment | 500 | — |
| Impairment of assets | 193 | 1,556 |
| Other, net | (69) | 81 |
| Changes in operating assets and liabilities: | | |
| Trade accounts receivable, including affiliates | 5,613 | (10,517) |
| Prepaid expenses and other current assets | (1,516) | (1,066) |
| Other non-current assets | 77 | (34) |
| Accounts payable and accrued liabilities | (14,180) | 10,043 |
| Other liabilities, including affiliates | 3,163 | 2,343 |
| Net cash provided by operating activities | 24,508 | 20,905 |
| Cash flows from investing activities: | | |
| Capital expenditures | (93,946) | (103,370) |
| Expenditures for assets subject to property damage claims, net of insurance proceeds and deductibles | (2,482) | (796) |
| Proceeds from sales of assets | 4,693 | 1,758 |
| Investment contribution to joint venture investments | (2,474) | (105) |
| Consideration paid for Holdings' drop-down acquisition | (15,000) | — |
| TexStar Rich Gas System acquisition from affiliate | — | (79,955) |
| Other acquisitions | — | (38,636) |
| Net cash used in investing activities | (109,209) | (221,104) |
| Cash flows from financing activities: | | |
| Proceeds from issuance of common units, net | — | 144,671 |
| Borrowings under our credit facility | 136,000 | 184,000 |
| Borrowings under our term loan agreement | — | 450,000 |
| Repayments under our credit facility | (31,000) | (442,300) |
| Repayments under our term loan agreement | (3,375) | (1,125) |
| Payments on capital lease obligations | (406) | (454) |
| Financing costs | (685) | (17,716) |
| Contributions from general partner | 1,301 | 9,967 |
| Payments of distributions and distribution equivalent rights | (35,088) | (42,711) |
| Expenses paid by Holdings on behalf of Valley Wells' assets | 17,858 | 17,872 |
| Assumption and repayment of debt in TexStar Rich Gas System Transaction | — | (100,000) |
| Valley Wells operating expense cap adjustment | 518 | — |

| | | |
|---|---|---|
| Other, net | (420) | (3,532) |
| Net cash provided by financing activities | 84,703 | 198,672 |
| | | |
| Net increase (decrease) in cash and cash equivalents | 2 | (1,527) |
| Cash and cash equivalents — Beginning of period | 1,649 | 3,349 |
| Cash and cash equivalents — End of period | $1,651 | $1,822 |

See accompanying notes.

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SOUTHCROSS ENERGY PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(In thousands)
(Unaudited)

| | Partners' Capital Limited Partners | | | | | |
|---|---|---|---|---|---|---|
| | Common | Class B Convertible | Subordinated | General Partner | Southcross Holdings' equity in contributed subsidiaries | Total |
| BALANCE - December 31, 2014 | $259,735 | $298,833 | $48,831 | $12,385 | $77,320 | $697,104 |
| Net loss | (16,583) | (9,722) | (7,755) | (696) | (4,258) | (39,014) |
| Contributions from general partner | — | — | — | 1,301 | — | 1,301 |
| Class B Convertible unit in-kind distribution | (5,340) | 8,059 | (2,557) | (162) | — | — |
| Unit-based compensation on long-term incentive plan | 3,384 | — | — | — | — | 3,384 |
| Cash distributions and distribution equivalent rights paid | (30,366) | — | (3,432) | (1,290) | — | (35,088) |
| Accrued distribution equivalent rights on long-term incentive plan | (703) | — | — | — | — | (703) |
| Tax withholdings on unit-based compensation vested units | (419) | — | — | — | — | (419) |
| General partner unit in-kind distribution | (112) | — | (53) | 165 | — | — |
| Valley Wells' operating expense cap adjustment | 1,023 | — | — | — | — | 1,023 |
| Purchase of assets in Holdings drop-down acquisition | 62,640 | — | — | — | (77,640) | (15,000) |
| Contribution of NGL pipelines in Holdings drop-down acquisition | — | — | — | — | 15,000 | 15,000 |
| Net assets contributed in Holdings drop-down acquisition in excess of consideration paid | 14,502 | 7,760 | 6,257 | 581 | (29,100) | — |
| Expenses paid by Holdings on behalf of Valley Wells' assets | — | — | — | — | 17,858 | 17,858 |
| Net liabilities assumed by Holdings in Holdings drop-down acquisition | — | — | — | — | 820 | 820 |
| BALANCE - September 30, 2015 | $287,761 | $304,930 | $41,291 | $12,284 | $— | $646,266 |

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| | Partners' Capital Limited Partners | | | | | | |
|---|---|---|---|---|---|---|---|
| | Common | Class B Convertible | Subordinated | General Partner | Southcross Holdings' equity in contributed subsidiaries | Accumulated Other Comprehensive Loss | Total |
| BALANCE - December 31, 2013 | $169,141 | $— | $99,726 | $6,367 | $— | $(210) | $275,024 |
| Net loss | (15,356) | (6,778) | (7,565) | (581) | — | — | (30,280) |
| Issuance of common units, net | 144,671 | — | — | — | — | — | 144,671 |
| Issuance of Class B Convertible units, net | — | 324,413 | — | — | — | — | 324,413 |
| Consideration paid in excess of purchase price for the TexStar Rich Gas System | (45,420) | (27,925) | (23,308) | (1,972) | — | — | (98,625) |
| Contributions from general partner | — | — | — | 9,967 | — | — | 9,967 |
| Class B Convertible unit in-kind distribution | (3,533) | 5,467 | (1,824) | (110) | — | — | — |
| Unit-based compensation on long-term incentive plan | 9,236 | — | — | — | — | — | 9,236 |
| Series A Preferred conversion into common units | 45,624 | — | — | — | — | — | 45,624 |
| Series A Preferred unit in-kind distribution and fair value adjustments | (3,126) | — | (1,897) | (107) | — | — | (5,130) |
| Cash distributions and distribution equivalent rights paid | (26,566) | — | (14,657) | (869) | — | — | (42,092) |
| Accrued distribution equivalent rights on long-term incentive plan | (562) | — | — | — | — | — | (562) |
| Tax withholdings on unit-based compensation vested units | (3,532) | — | — | — | — | — | (3,532) |
| General partner unit in-kind distribution | (78) | — | (45) | 123 | — | — | — |
| Net effect of cash flow hedges | — | — | — | — | — | 210 | 210 |
| Expenses paid by Southcross Holdings on behalf of Valley Wells and Compressor Assets | — | — | — | — | 17,872 | — | 17,872 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| BALANCE - September 30, 2014 | $270,499 | $295,177 | $50,430 | $12,818 | $17,872 | $— | $646,796 |

See accompanying notes.

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SOUTHCROSS ENERGY PARTNERS, L.P.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. ORGANIZATION AND DESCRIPTION OF BUSINESS

Organization

Southcross Energy Partners, L.P. (the "Partnership," "Southcross," "we," "our" or "us") is a Delaware limited partnership formed in April 2012. Our common units are listed on the New York Stock Exchange under the symbol “SXE.”

Until August 4, 2014, Southcross Energy LLC, a Delaware limited liability company, held all of the equity interests in Southcross Energy Partners GP, LLC, a Delaware limited liability company and our general partner (“General Partner”), all of our subordinated units and a portion of our common units. Southcross Energy LLC is controlled through investment funds and entities associated with Charlesbank Capital Partners, LLC (“Charlesbank”).

Holdings Transaction

On August 4, 2014, Southcross Energy LLC and TexStar Midstream Services, LP, a Texas limited partnership (“TexStar”), combined pursuant to a contribution agreement in which Southcross Holdings LP, a Delaware limited partnership (“Holdings”), was formed (the “Holdings Transaction”). As a result of the Holdings Transaction, Holdings indirectly owns 100% of our General Partner (and therefore controls us), all of our subordinated units and a portion of our common units. Our General Partner owns an approximate 2.0% interest in us and all of our incentive distribution rights. Charlesbank, EIG Global Energy Partners, LLC (“EIG”) and Tailwater Capital LLC (“Tailwater”) (collectively, the “Sponsors”) each indirectly own approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine Opportunities Fund and GE Energy Financial Services also own certain additional equity interests in Holdings.

TexStar Rich Gas System Transaction

Contemporaneously with the closing of the Holdings Transaction, TexStar contributed to us certain gathering and processing assets (the “TexStar Rich Gas System”), which were owned by TexStar (the “TexStar Rich Gas System Transaction”). For additional details regarding the Holdings Transaction and the TexStar Rich Gas System Transaction, see Notes 2, 6, 9, 10, and 13.

Holdings Drop-Down Acquisition

On May 7, 2015, we acquired gathering, treating, compression and transportation assets (the “2015 Holdings Acquisition”) from Holdings and its subsidiaries consisting of the Valley Wells sour gas gathering and treating system, compression assets that are part of the Valley Wells and Lancaster gathering and treating systems and two NGL pipelines. For additional details regarding the 2015 Holdings Acquisition, see Notes 2 and 9.

Liquidity Consideration

Beginning in the second half of 2014 and continuing through the issuance of these financial statements, commodity prices have experienced increased volatility. In particular, natural gas, crude oil and NGL prices have decreased significantly. If a material reduction in drilling for oil or natural gas continues in the geographic areas in which we operate, including the Eagle Ford Shale region, or significant, prolonged pricing deterioration continues for commodities we sell, our future cash flow may be materially adversely affected.

The majority of our revenue is derived from fixed-fee contracts, which have limited direct exposure to commodity price levels since we are paid based on the volumes of natural gas that we gather, process, treat, compress and transport and the volumes of NGLs we fractionate and transport, rather than being paid based on the value of the underlying natural gas or NGLs. In addition, a percentage of our contract portfolio contains minimum volume commitment arrangements. The majority of our volumes are dependent upon the level of producer drilling activity. After considering these uncertainties, we anticipate potential future shortfalls in the amount of consolidated EBITDA (as defined in the Third Amended and Restated Revolving Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, JPMorgan Chase Bank, N.A., as Documentation Agent, and a syndicate of lenders (the “Third A&R Revolving Credit Agreement”), as amended in May 2015) necessary to remain in compliance with the consolidated total leverage ratio of our Financial Covenants (as defined in Note 6)

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in our Credit Facility. As discussed in further detail in Note 6, we have the right to cure such a Financial Covenant Default (as defined in Note 6) by either our Sponsors or Holdings purchasing equity interests in or making capital contributions (an equity cure) resulting in, among other things, proceeds that, if added to consolidated EBITDA, would result in us satisfying the Financial Covenants. Once such an equity cure is made, it is included in our consolidated EBITDA calculation in any rolling twelve month period that includes the quarter that was cured. Should there be an event of default under the Credit Facility, and such default is not cured, we would also experience a cross default under our Term Loan Agreement (defined in Note 6) and all of our debt would become due and payable to our lenders.

As of September 30, 2015, we determined that we will not be in compliance with the consolidated total leverage ratio of our Financial Covenants absent an equity cure of approximately \$5.3 million within approximately 15 days following the issuance of these financial statements. We believe that we will have the ability to fund this equity cure with the remaining \$8.3 million non-cash equity cure credit amount from our Credit Agreement Amendment (as defined in Note 6). We used \$4.7 million of the contractual \$13.0 million non-cash equity cure credit amount from our Credit Agreement Amendment to fund an equity cure as of June 30, 2015 in order to stay in compliance with the consolidated total leverage ratio of our Financial Covenants. We anticipate funding additional equity cures needed to maintain compliance with our Financial Covenants through the end of 2016 with the remainder of the non-cash equity cure credit amount, the \$50 million Sponsor equity commitment described below, or a combination of the two.

In response to our need for additional liquidity and to maintain compliance with our Financial Covenants, our Sponsors have committed to provide the necessary funding to support us for at least a reasonable period of time in an amount up to \$50 million, which was increased from \$25 million in August 2015, to ensure we have sufficient liquidity to comply with applicable Financial Covenants and to fund normal operating and growth capital requirements. Therefore, these financial statements have been presented as if we will continue as a going concern. See Note 6.

Description of Business

We are a master limited partnership, headquartered in Dallas, Texas, that provides natural gas gathering, processing, treating, compression and transportation services and NGL fractionation and transportation services. We also source, purchase, transport and sell natural gas and NGLs. Our assets are located in South Texas, Mississippi and Alabama and include four gas processing plants, two fractionation facilities and our pipelines.

Segments

Our chief operating decision maker is our General Partner’s Chief Executive Officer, who reviews financial information presented on a consolidated basis in order to assess our performance and make decisions about resource allocations. There are no segment managers who are held accountable by the chief operating decision maker, or anyone else, for operations, operating results and planning for levels or components below the consolidated unit level. Accordingly, we have determined that we have one reportable segment.

Basis of Presentation

We prepared this report under the rules and regulations of the Securities and Exchange Commission (the “SEC”) and in accordance with accounting principles generally accepted in the United States of America (“GAAP”) for interim financial statements. Accordingly, these condensed consolidated financial statements do not include all of the disclosures required by GAAP and should be read in conjunction with our 2014 Annual Report on Form 10-K as updated by the Current Report on Form 8-K dated August 20, 2015 (“2014 Annual Report on Form 10-K”). The condensed consolidated financial statements as of September 30, 2015 and December 31, 2014, and for the three and nine months ended September 30, 2015 and 2014, are unaudited and have been prepared on the same basis as the audited financial statements included in our 2014 Annual Report on Form 10-K. Adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the results of operations and financial position have been included herein. All intercompany accounts and transactions have been eliminated in the preparation of the accompanying condensed consolidated financial statements.

The condensed consolidated financial statements reflect the assets acquired and liabilities assumed and the related operating results associated with (i) the Onyx pipelines acquisition on March 6, 2014, (ii) the TexStar Rich Gas System Transaction and the 2015 Holdings Acquisition on August 4, 2014, (iii) and the Texoz acquisition on November 21, 2014. See Note 2.

As a result of the Holdings Transaction, Holdings acquired a controlling equity interest in the Partnership, which was accounted for under the acquisition method of accounting in the consolidated financial statements of Holdings, whereby Holdings recorded the Partnership's assets acquired and liabilities assumed at fair value.

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Additionally, because the TexStar Rich Gas System was owned by TexStar, the Partnership recorded the TexStar Rich Gas System at TexStar's historical cost. Thus, the difference between consideration paid and the TexStar Rich Gas System's historical cost (net book value) at August 4, 2014, the date on which the Holdings Transaction and the TexStar Rich Gas System Transaction closed, was recorded as a reduction to partners' capital. Management concluded that the Partnership was the predecessor for accounting purposes for periods prior to August 4, 2014.

We recognized the 2015 Holdings Acquisition at Holdings' historical cost because the acquisition was executed by entities under common control. Thus, the difference between consideration paid and Holdings' historical cost (net book value) at May 7, 2015, the date on which the 2015 Holdings Acquisition closed, was recorded as a reduction to partners' capital. Due to the common control aspect, the 2015 Holdings Acquisition was accounted for by the Partnership on an "as if pooled" basis for the periods during which common control existed which began on August 4, 2014. See Note 2.

The accompanying unaudited condensed consolidated financial statements were prepared in conformity with GAAP, which requires management to make various estimates and assumptions that may affect the amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results may differ from those estimates. Information for interim periods may not be indicative of our operating results for the entire year.

The disclosures included in this report provide an update to our 2014 Annual Report on Form 10-K.

We evaluate events that occur after the balance sheet date, but before the financial statements are issued, for potential recognition or disclosure. Based on the evaluation, we determined that there were no material subsequent events for recognition or disclosure other than those disclosed in this report.

Significant Accounting Policies

During the third quarter of 2015, there were no material changes to our significant accounting policies described in Note 1 of our 2014 Annual Report on Form 10-K.

Recent Accounting Pronouncements

Accounting standard-setting organizations frequently issue new or revised accounting pronouncements. We review and evaluate new pronouncements and existing pronouncements below to determine their impact, if any, on our consolidated financial statements. We are evaluating the impact of each pronouncement on our consolidated financial statements.

In 2014, a comprehensive new revenue recognition standard that will supersede substantially all existing revenue recognition guidance under GAAP was issued. The standard's core principle is that a company will recognize revenue when it transfers promised goods or services to customers and in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In July 2015, the Financial Accounting Standards Board ("FASB") voted to defer the new revenue recognition standard. The standard is currently set to be effective in the first quarter of 2018.

In February 2015, the FASB issued a pronouncement that amended current consolidation guidance with regard to variable interest entities and voting interest entities. This standard will become effective beginning in 2016.

In April 2015, the FASB issued a pronouncement simplifying the presentation of debt issuance costs effective beginning in 2016. The amendment requires that debt issuance costs related to a recognized debt liability be presented on the balance sheet as a reduction to the carrying amount of that debt liability, consistent with the presentation for debt discounts. The recognition and measurement guidance for debt issuance costs is not affected by the amendments. In August 2015, the FASB further clarified that the SEC staff would not object to a similar capitalization and amortization of deferred issuance costs for line of credit arrangements.

In April 2015, the FASB issued a pronouncement that specifies how to calculate historical earnings per unit for a master limited partnership with retrospectively adjusted financial statements subsequent to a drop-down acquisition. The amendments specify that for purposes of calculating historical earnings per unit under the two-class method, the earnings or losses of a transferred business before the date of a drop-down acquisition are to be allocated entirely to the general partner. In that circumstance, the previously reported earnings per unit of the limited partners would not change as a result of the drop-down acquisition. Qualitative disclosures about how the rights to the earnings or losses differ before and after the drop-down

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acquisition occurs for purposes of computing earnings per unit under the two-class method are also required. This standard will become effective beginning in 2016, however we have elected to early adopt this standard in this report. See Note 3.

In September 2015, the FASB issued a pronouncement simplifying the recognition of provisional amounts that are identified during the measurement period of an acquisition. The amendments require an entity to present separately on the face of the income statement or disclose in the notes to the financial statements the portion of the amount recorded in the current period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. This standard will become effective beginning in 2016.

2. ACQUISITIONS

TexStar Rich Gas System Transaction. On August 4, 2014, contemporaneously with the closing of the Holdings Transaction, TexStar contributed to us the TexStar Rich Gas System through a contribution of TexStar's equity interest in the entities that own the TexStar Rich Gas System (the "Contribution"). In exchange for the Contribution, we paid $80 million in cash, assumed $100 million of debt (which was immediately repaid through our Term Loan Agreement (as defined in Note 6)) and issued 14,633,000 Class B Convertible Units (the "Class B Convertible Units"). The TexStar Rich Gas System consists of a cryogenic processing plant, located in Bee County, Texas, and joint venture ownership in natural gas gathering and residue pipelines across the core producing areas extending from Dimmit to Karnes Counties, Texas in the liquids-rich window of the Eagle Ford Shale region. These pipelines are operated under split-capacity arrangements within joint venture arrangements with Targa Pipeline Partners LP ("Targa") (see Note 13).

The amount of the consideration paid over TexStar's net book value of the assets received and liabilities assumed of the TexStar Rich Gas System was recorded as a reduction to partners' capital as summarized as follows (in thousands):

| | |
|---|---|
| Consideration paid (1) | $404,414 |
| Current assets | $1,295 |
| Property, plant and equipment, net | 255,220 |
| Investments in joint ventures(2) | 152,050 |
| Total assets contributed | 408,565 |
| Total liabilities assumed (3) | (102,776 ) |
| Net identifiable assets contributed | $305,789 |
| Consideration paid in excess of net assets contributed | $98,625 |
| Allocation of reduction to partners' capital: | |
| Common limited partner interest | $45,420 |
| Class B Convertible limited partner interest | 27,925 |
| Subordinated limited partner interest | 23,308 |
| General Partner interest | 1,972 |
| Total reduction to partners' capital | $98,625 |

(1) This amount was calculated as follows: $80 million of cash plus 14,633,000 Class B Convertible Units at an issue price of $22.17, the closing price of the Partnership's common units on August 4, 2014.
(2) Significant assets acquired through the TexStar Rich Gas System Transaction include equity interests in three joint ventures. See Note 13.
(3) This amount includes $100 million of debt assumed.

Onyx Pipelines Acquisition. On March 6, 2014, our subsidiary, Southcross Nueces Pipelines LLC, acquired natural gas pipelines near Corpus Christi, Texas and contracts related to these pipelines from Onyx Midstream, LP and Onyx Pipeline Company (collectively, "Onyx") for $38.6 million in cash, net of certain adjustments as provided in the purchase agreement.

The pipelines transport natural gas to two power plants in Nueces County, Texas under fixed-fee contracts that extend through 2029 and include an option to extend the agreements by an additional term of up to ten years. The contracts were renegotiated in connection with the acquisition; therefore, we considered these contracts to be assumed at fair market value.

The fair values of the property, plant and equipment were based upon then current assumptions related to expected future cash flows, discount rates and asset lives. We utilized a mix of the cost, income and market approaches to determine the

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estimated fair values of such assets. The fair value measurements and models were classified as non-recurring Level 3 measurements.

We performed our assessment of the fair value of the assets acquired and liabilities assumed, and determined that the consideration given was equal to the fair value of net assets acquired. As a result, no goodwill was recorded. The assessment was finalized during the second quarter of 2014 and there were no changes to the preliminary balances recorded.

The fair value of the assets acquired and liabilities assumed related to the Onyx purchase price was as follows (in thousands):

| | |
|---|---|
| Purchase Price—Cash | $38,636 |
| Current assets | $730 |
| Property, plant and equipment | 39,413 |
| Total assets acquired | 40,143 |
| Current liabilities assumed | (1,407) |
| Other liabilities assumed | (100) |
| Net identifiable assets acquired | $38,636 |

Unaudited Pro Forma Financial Information for Onyx Pipelines Acquisition. The following unaudited pro forma financial information for the nine months ended September 30, 2014 assumes that the acquisition of pipelines from Onyx occurred on January 1, 2013 and includes adjustments for income from operations, including depreciation and amortization, as well as the effects of financing the transaction (in thousands, except per unit information):

| | Nine Months Ended September 30, 2014 |
|---|---|
| Total revenue | $620,796 |
| Net loss | (29,104) |
| Net loss attributable to common unitholders | (19,132) |
| Net loss per common unit (basic and diluted) | (0.91) |
| Net loss attributable to subordinated unitholders | (7,823) |
| Net loss per subordinated unit (basic and diluted) | (0.64) |

The unaudited pro forma information is not necessarily indicative of what our statements of operations would have been if the transaction had occurred on that date, or what the financial position or results from operations will be for any future periods. For the period from March 6, 2014 through September 30, 2014, the Onyx pipelines business contributed $3.0 million in revenues and $0.9 million in net income to our statements of operations.

Texoz Acquisition. On November 21, 2014, we completed the acquisition of a natural gas gathering system in McMullen County, Texas (the “Texoz System”) from LT Gathering, LLC for $5.4 million in cash, net of certain adjustments as provided in the purchase agreement (the “Texoz Acquisition”). The Texoz System consists of eight miles of gathering pipelines within two miles of our existing rich gas pipeline network and services customers under acreage dedication contracts. Due to the immaterial amount of this transaction, no pro-forma financial information has been presented.

Holdings Drop-Down Acquisition. On May 7, 2015, we completed the 2015 Holdings Acquisition pursuant to a Purchase, Sale and Contribution Agreement among Holdings, TexStar Midstream Utility, LP, Frio LaSalle Pipeline, LP (“Frio”), us and certain of our subsidiaries. The acquired assets consist of the Valley Wells sour gas gathering and treating system (the “Valley Wells System”), compression assets that are part of the Valley Wells and Lancaster gathering and treating systems (the “Compression Assets”) and two NGL pipelines. Total consideration for the assets was $77.6 million, consisting of $15.0 million in cash and 4.5 million new common units, valued as of the date of closing, issued to Holdings. Also, we assumed the remaining capital expenditures for the completion of the NGL pipelines that were under construction at the time of acquisition.

The Valley Wells System is located in the Eagle Ford Shale region, in LaSalle County, Texas. The system has sour gas treating capacity of approximately 100 MMcf/d and is supported by a 60 MMcf/d minimum volume commitment from Holdings for gathering and treating services, while Holdings has producer contracts with minimum volume commitments totaling 35 MMcf/d behind the system. The system is connected to our rich gas system for transport and processing. The assets acquired in the 2015 Holdings Acquisition include over 50,000 horsepower of compression capability that serve both the Valley

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Wells and Lancaster gathering systems located primarily in Dimmit, Frio and LaSalle counties. The NGL pipelines, which were completed in June 2015, include a Y-grade pipeline that connects our Woodsboro processing facility to Holdings' Robstown fractionator ("Robstown") and a propane pipeline from our Bonnie View fractionator to Robstown. Because of the common control aspects in the 2015 Holdings Acquisition, the 2015 Holdings Acquisition was deemed a transaction between entities under common control and, as such, was accounted for on an "as if pooled" basis for all periods which common control existed (which began on August 4, 2014). The Partnership's financial results retrospectively include the Valley Wells' and Compression Assets' financial results for all periods ending after August 4, 2014, the date of the Holdings Transaction, and before May 7, 2015. The acquired NGL pipelines were accounted for as an asset acquisition and have been included in the historical financial statements beginning on May 7, 2015. As a carve-out transaction, the 2015 Holdings Acquisition has no cash accounts. As such, accounts receivable and accounts payable, along with certain other assets and liabilities that would be settled in cash, were the rights and obligations of Holdings. We are still evaluating the effect of certain liabilities at our parent company and how they should be treated going forward. Given their nature and the fact that carve-out financial statements are meant to represent an entity's operations as if it had existed as of the time common control occurred, we have presented these amounts as third-party receivables and payables.

The amount of the consideration paid below Holdings' net book value of the assets received and liabilities assumed of the 2015 Holdings Acquisition was recorded as an increase to partners' capital as summarized as follows (in thousands):

| | |
|---|---|
| Consideration paid(1) | $77,640 |
| Total net assets contributed | 106,740 |
| Net assets contributed in excess of consideration paid | $29,100 |
| Allocation of increase to partners' capital: | |
| Common limited partner interest | $14,502 |
| Class B Convertible limited partner interest | 7,760 |
| Subordinated limited partner interest | 6,257 |
| General Partner interest | 581 |
| Total increase to partners' capital | $29,100 |

(1) This amount was calculated as follows: $15.0 million of cash plus 4.5 million new common units at an issue price of $13.92, the closing price of the Partnership's common units on May 7, 2015.

Supplemental Disclosures - As If Pooled Basis. As noted above, the 2015 Holdings Acquisition was between commonly controlled entities which required that we account for the acquisitions in a manner similar to a pooling of interests. As a result, the historical financial statements of the Partnership and the Valley Wells System and Compression Assets have been combined to reflect the historical operations, financial position and cash flows from the date common control began on August 4, 2014. Revenues and net income for the previously separate entities and the combined amounts for the nine months ended September 30, 2015 and three and nine months ended September 30, 2014, are as follows (in thousands):

| | Nine Months Ended September 30, 2015 | Three Months Ended September 30, 2014 | Nine months ended September 30, 2014 |
|---|---|---|---|
| Partnership revenues | $525,679 | $211,493 | $620,147 |
| Valley Wells System and Compression Assets revenue(1) | 7,049 | 1,185 | 1,185 |
| Combined revenues | $532,728 | $212,678 | $621,332 |
| | | | |
| Partnership net loss | $(34,756) | $(24,778) | $(29,026) |
| Valley Wells System and Compression Assets net loss(1) | (4,258) | (1,254) | (1,254) |
| Combined net loss | $(39,014) | $(26,032) | $(30,280) |

(1) Results are fully reflected in the Partnership's results of operations for the nine months ended September 30, 2015.

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3. NET LOSS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS

Net Loss Per Limited Partner Unit

The following is a reconciliation of the net loss attributable to our limited partners and our limited partner units and the basic and diluted earnings per unit calculations for the three and nine months ended September 30, 2015 and 2014 (in thousands, except unit and per unit data):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Net loss | $(9,659) | $(26,032) | $(39,014) | $(30,280) |
| Series A Preferred unit fair value adjustment [(1)] | — | 424 | — | (4,596) |
| Series A Preferred unit in-kind distribution | — | — | — | (534) |
| General partner unit in-kind distribution | (28) | (112) | (165) | (123) |
| Net loss attributable to Holdings | — | (1,254) | (4,258) | (1,254) |
| Net loss attributable to partners | $(9,687) | $(24,466) | $(34,921) | $(34,279) |
| | | | | |
| General partner's interest [(2)] | $(201) | $(523) | $(711) | $(622) |
| Class B Convertible limited partner interest [(2)] | (2,622) | (6,778) | (9,722) | (6,778) |
| Limited partners' interest [(2)] | | | | |
| Common | $(4,799) | $(11,156) | $(16,711) | $(19,084) |
| Subordinated | (2,065) | (6,009) | (7,777) | (7,795) |

(1) The valuation adjustment to maximum redemption value of the Series A Preferred unit in-kind distribution decreased the net loss attributable to partners for the three months ended September 30, 2014 and increased the net loss attributable to partners for the nine months ended September 30, 2014.

(2) General Partner's and limited partners' interests are calculated based on the allocation of net losses for the period, net of the allocation of Series A Preferred unit in-kind distributions, Series A Preferred Unit fair value adjustments and General Partner unit in-kind distributions. The Class B Convertible Unit interest is calculated based on the allocation of only net losses for the period.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Common Units | 2015 | 2014 | 2015 | 2014 |
| Interest in net loss | $(4,799) | $(11,156) | $(16,711) | $(19,084) |
| Effect of dilutive units - numerator [(1)] | — | — | — | — |
| Dilutive interest in net loss | $(4,799) | $(11,156) | $(16,711) | $(19,084) |
| | | | | |
| Weighted-average units - basic | 28,371,903 | 22,925,979 | 26,233,614 | 20,911,472 |
| Effect of dilutive units - denominator [(1)] | — | — | — | — |
| Weighted-average units - dilutive | 28,371,903 | 22,925,979 | 26,233,614 | 20,911,472 |
| | | | | |
| Basic and diluted net loss per common unit | $(0.17) | $(0.49) | $(0.64) | $(0.91) |

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| Subordinated Units | Three Months Ended September 30, 2015 | 2014 | Nine Months Ended September 30, 2015 | 2014 |
|---|---|---|---|---|
| Interest in net loss | $(2,065) | $(6,009) | $(7,777) | $(7,795) |
| Effect of dilutive units - numerator[(1)] | — | — | — | — |
| Dilutive interest in net loss | $(2,065) | $(6,009) | $(7,777) | $(7,795) |
| | | | | |
| Weighted-average units - basic | 12,213,713 | 12,213,713 | 12,213,713 | 12,213,713 |
| Effect of dilutive units - denominator[(1)] | — | — | — | — |
| Weighted-average units - dilutive | 12,213,713 | 12,213,713 | 12,213,713 | 12,213,713 |
| | | | | |
| Basic and diluted net loss per subordinated unit | $(0.17) | $(0.49) | $(0.64) | $(0.64) |

(1) Because we had a net loss for all periods for common units and the subordinated units, the effect of the dilutive units would be anti-dilutive to the per unit calculation. Therefore, the weighted average units outstanding are the same for basic and dilutive net loss per unit for those periods. The weighted average units that were not included in the computation of diluted per unit amounts were 4,526 and 11,464 for the three and nine months ended September 30, 2015, respectively.

Our calculation of the number of weighted-average units outstanding includes the common units that have been awarded to our directors that are deferred under our Non-Employee Director Deferred Compensation Plan.

All of our Series A Preferred Units were converted into common units on August 4, 2014 (see Note 8). Prior to conversion, our Series A Preferred Units were considered participating securities for purposes of the basic earnings per unit calculation during periods in which they received cash distributions. We were required to pay in-kind distributions to the Series A Preferred Units for the first four full quarters beginning the second quarter of 2013, and continued to pay these distributions until the Series A Preferred Units were converted into common units. Because the Series A Preferred Units received in-kind distributions, they have been excluded from the basic earnings per unit calculation for the three and nine months ended September 30, 2014.

Distributions

Our agreement of limited partnership, which was amended and restated on August 4, 2014 in order to establish the Class B Convertible Units (as amended and restated, our “Partnership Agreement”), requires that within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our General Partner. Subject to the waiver and credit agreement restriction, described below, we intend to make a minimum quarterly distribution to the holders of our common units and subordinated units of $0.40 per unit, or $1.60 on an annualized basis, to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our General Partner. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Beginning with the third quarter of 2014, until such time that we have a distributable cash flow divided by cash distributions ratio (“Distributable Cash Flow Ratio”) of at least 1.0, Holdings, the indirect holder of all of our subordinated units, waived the right to receive distributions on any subordinated units that would cause the Distributable Cash Flow Ratio to be less than 1.0. In addition, the Credit Agreement Amendment (as defined in Note 6) imposed additional restrictions on our ability to declare and pay quarterly cash distributions with respect to our subordinated units. See Note 6.

With respect to the fourth quarter of 2014, Holdings also waived the requirement that any distribution owed to it for that quarter be paid within 45 days of the end of the quarter, provided that the distribution was paid before or in conjunction with the filing of our 2014 Annual Report on Form 10-K. We paid a distribution of $0.28 per unit on our 12,213,713 subordinated units in conjunction with the filing of our 2014 Annual Report on Form 10-K.

Holdings did not receive a distribution for the first quarter of 2015 in respect of the 4.5 million common units acquired by it in connection with the 2015 Holdings Acquisition.

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Paid In-Kind Distributions

Series A Preferred Units. During the second quarter of 2013, we raised $40.0 million of equity through issuances of 1,715,000 Series A Preferred Units and an additional General Partner contribution to satisfy the requirements of our Previous Credit Facility (as defined in Note 6) (see Notes 6 and 8). Under the terms of our Partnership Agreement, we were required to pay the holders of our Series A Preferred Units quarterly distributions of in-kind Series A Preferred Units for the first four full quarters following the issuance of the units and continuing thereafter until the board of directors of our General Partner determined to begin paying quarterly distributions in cash. In-kind distributions were in the form of Series A Preferred Units at a rate of $0.40 per outstanding Series A Preferred Unit per quarter (or 7% per year of the per unit purchase price). Cash distributions were required to equal the greater of $0.40 per unit per quarter or the quarterly distribution paid with respect to each common unit. In accordance with the Partnership Agreement, our General Partner received a corresponding distribution of in-kind general partner units to maintain its 2.0% interest in us. In connection with the Holdings Transaction (see Notes 1 and 2), all holders of the Series A Preferred Units elected to convert their Series A Preferred Units into 2,015,638 common units based on a 110% exchange ratio.

The following table represents the paid in-kind ("PIK") distribution declared in 2014 through August 4, 2014, the date on which all outstanding Series A Preferred Units were converted to common units (in thousands, except per unit and in-kind distribution units):

| Payment Date | Attributable to the Quarter Ended(1) | Per Unit Distribution | In-Kind Series A Preferred Unit Distributions to Series A Preferred Holders | In-Kind Series A Preferred Distributions Value(2) | In-Kind Unit Distribution to General Partner | In-Kind General Partner Distribution Value(2) |
|---|---|---|---|---|---|---|
| 2014 | | | | | | |
| May 15, 2014 | March 31, 2014 | $0.40 | 31,513 | $534 | 643 | $ 11 |

(1) As a result of the conversion, the Series A Preferred Unit holders (and the corresponding General Partner units) ceased receiving PIK distributions effective with the quarter ended June 30, 2014, but received a cash distribution on the converted common units.
(2) The fair value was calculated as required, based on the common unit price at the quarter end date for the period attributable to the distribution, multiplied by the number of units distributed.

Class B Convertible Units. In connection with the Contribution and the TexStar Rich Gas System Transaction, on August 4, 2014, we established our Class B Convertible Units. As of September 30, 2015, the Class B Convertible Units consisted of 15,684,512 of such units including the additional Class B Convertible Units issued in-kind as a distribution ("Class B PIK Units"). The Class B Convertible Units are not participating securities for purposes of the earnings per unit calculation. Commencing with the quarter ended September 30, 2014 and until converted, as long as certain requirements are met, the holders of the Class B Convertible Units will receive quarterly distributions in an amount equal to $0.3257 per unit paid in Class B PIK Units (based on a unit issuance price of $18.61) within 45 days after the end of each quarter. Our General Partner was entitled, and has exercised its right, to retain its 2.0% general partner interest in us in connection with the original issuance of 14,633,000 Class B Convertible Units. In connection with future distributions of Class B PIK Units, the General Partner is entitled to a corresponding distribution to maintain its 2.0% general partner interest in us. The Class B Convertible Units have the same rights, preferences and privileges, and are subject to the same duties and obligations, as our common units, with certain exceptions. See Note 9.

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The following table presents the PIK distribution earned on the Class B Convertible Units for periods after issuance on August 4, 2014 through September 30, 2015 (in thousands, except per unit and in-kind distribution units):

| Payment Date | Attributable to the Quarter Ended | Per Unit Distribution | In-Kind Class B Convertible Unit Distributions to Class B Convertible Holders | In-Kind Class B Convertible Distributions Value(1) | In-Kind Unit Distribution to General Partner | In-Kind General Partner Distribution Value(1) |
|---|---|---|---|---|---|---|
| 2015 | | | | | | |
| November 13, 2015 | September 30, 2015 | $0.3257 | 274,478 | $1,353 | 5,601 | $ 28 |
| August 14, 2015 | June 30, 2015 | 0.3257 | 269,758 | 2,994 | 5,505 | 61 |
| May 14, 2015 | March 31, 2015 | 0.3257 | 265,118 | 3,712 | 5,410 | 76 |
| 2014 | | | | | | |
| February 13, 2015 | December 31, 2014 | 0.3257 | 260,558 | 4,143 | 5,318 | 85 |
| November 14, 2014 | September 30, 2014 | 0.3257 | 256,078 | 5,467 | 5,226 | 112 |

(1) The fair value was calculated as required, based on the common unit price at the quarter end date for the period attributable to the distribution, multiplied by the number of units distributed.

Cash Distributions

The following table represents our distributions declared for the quarterly periods beginning in 2014 through the nine months ended September 30, 2015 (in thousands, except per unit data):

| Payment Date | Attributable to the Quarter Ended | Per Unit Distribution | Distributions Limited Partners Common | Subordinated | General Partner | Total |
|---|---|---|---|---|---|---|
| 2015 | | | | | | |
| November 13, 2015 | September 30, 2015 | $0.40 | $11,367 | $— | $ 459 | $11,826 |
| August 14, 2015 | June 30, 2015 | 0.40 | 11,325 | — | 457 | 11,782 |
| May 14, 2015 | March 31, 2015 | 0.40 | 9,520 | — | 418 | 9,938 |
| 2014 | | | | | | |
| February 13, 2015 | December 31, 2014 | 0.40 (1) | 9,520 | 3,432 (2) | 416 | 13,368 |
| November 14, 2014 | September 30, 2014 | 0.40 (1) | 9,520 | — | 413 | 9,933 |
| August 14, 2014 | June 30, 2014 | 0.40 | 9,399 | 4,886 | 290 | 14,575 |
| May 15, 2014 | March 31, 2014 | 0.40 | 8,586 | 4,886 | 290 | 13,762 |

(1) The common unit distribution in the table above includes the distribution payment to the Series A Preferred unitholders for their Series A Preferred Units converted into common units or to the units that vested as part of our LTIP (as defined in Note 11) as a result of the Holdings Transaction (see Notes 1, 8 and 11).
(2) Holdings waived the requirement that any distribution owed to it for the fourth quarter be paid within 45 days of the end of the quarter. We paid a distribution of $0.28 per unit on our 12,213,713 subordinated units in conjunction with the filing of our 2014 Annual Report on Form 10-K.

4. FINANCIAL INSTRUMENTS

Fair Value Measurements

We apply recurring fair value measurements to our financial assets and liabilities. In estimating fair value, we generally use a market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. The fair value measurement inputs we use vary from readily observable inputs that represent market data obtained from independent sources to unobservable inputs that reflect our own market assumptions that cannot be validated through external pricing sources. Based on the observability of the inputs used in the valuation techniques, the financial assets and liabilities carried at fair value in the financial statements are classified as follows:

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- Level 1—Represents unadjusted quoted market prices in active markets for identical assets or liabilities that are accessible at the measurement date. This category primarily includes our cash and cash equivalents, accounts receivable and accounts payable.
- Level 2—Represents quoted market prices for similar assets or liabilities in active markets, quoted market prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. This category primarily includes variable rate debt, over-the-counter swap contracts based upon natural gas price indices and interest rate derivative transactions.
- Level 3—Represents derivative instruments whose fair value is estimated based on internally developed models and methodologies utilizing significant inputs that are generally less readily observable from market sources. We do not have financial assets and liabilities classified as Level 3.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, the level in the fair value hierarchy must be determined based on the lowest level input that is significant to the fair value measurement. An assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and consideration of factors specific to the asset or liability.

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable represent fair values based on the short-term nature of these instruments. The fair value of the debt funded through our credit facilities approximates its carrying amount due primarily to the variable nature of the interest rate of the instrument and is considered a Level 2 fair value measurement.

Derivative Financial Instruments

Interest Rate Derivative Transactions

We manage a portion of our interest rate risk through interest rate swaps and interest rate caps. In March 2012, we terminated an interest rate cap contract and entered into an interest rate swap contract with Wells Fargo, N.A. The interest rate swap had a notional value of $150.0 million, and a maturity date of June 30, 2014. We received a floating rate based upon one-month London Interbank Offered Rate (“LIBOR”) and paid a fixed rate under the interest rate swap of 0.54%.

The interest rate swap was designated as a cash flow hedge for accounting purposes at inception of the contract and, thus, to the extent the cash flow hedge was effective, unrealized gains and losses were recorded to accumulated other comprehensive income/loss and recognized in interest expense as the underlying hedged transactions (interest payments) were recorded. Any hedge ineffectiveness was recognized in interest expense immediately. We did not have any hedge ineffectiveness during the three and nine months ended September 30, 2014.

In February 2014, we discontinued cash flow hedge accounting on a prospective basis as a result of the $148.5 million repayment of borrowings under our Previous Credit Facility (as defined in Note 6). The fair value of the interest rate swap recorded in accumulated other comprehensive loss at the cash flow hedge de-designation date was $0.1 million. This balance was reclassified into interest expense as interest on the hedged debt was recorded. No ineffectiveness was recorded as a result of the cash flow hedge de-designation. Changes in the fair value of the interest rate swap for the remainder of the contract term were recognized in interest expense.

The effect of the interest rate swap designated as a cash flow hedge in our statements of changes in partners’ capital and comprehensive loss was as follows (in thousands):

| | Three Months Ended September 30, 2014 | Nine Months Ended September 30, 2014 |
|---|---|---|
| Change in value recognized in other comprehensive loss - effective portion | $— | $(11 ) |

| | | |
|---|---|---|
| Loss reclassified from accumulated other comprehensive loss to interest expense | — | 221 |

There were no amounts of gains or losses reclassified into earnings as a result of the discontinuance of cash flow hedge accounting due to the lack of probability of the forecasted transaction occurring.

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We enter into interest rate swap contracts whereby we receive a floating rate and pay a fixed rate to reduce the risk associated with the variability of interest rates for our term loan borrowings. Our interest rate swap position was as follows (in thousands):

| Notional Amount | Fixed Rate | Effective Date | Maturity Date | Estimated Fair Value September 30, 2015 |
|---|---|---|---|---|
| $50,000 | 1.198 % | September 30, 2014 | June 30, 2016 | $(71) |
| 50,000 | 1.196 % | September 30, 2014 | June 30, 2016 | (70) |
| 100,000 | 1.195 % | June 30, 2015 | January 1, 2017 | (190) |
| | | | | $(331) |

We enter into interest rate cap contracts to effectively limit our LIBOR-based interest rate risk on the portion of debt hedged at the contracted cap rate. Our interest rate cap position was as follows (in thousands):

| Notional Amount | Cap Rate | Effective Date | Maturity Date | Estimated Fair Value September 30, 2015 |
|---|---|---|---|---|
| $20,000 | 1.500 % | December 31, 2014 | December 31, 2016 | $3 |
| 80,000 | 3.000 % | June 30, 2015 | June 30, 2017 | 6 |
| | | | | $9 |

These interest rate derivatives are not designated as cash flow hedges and as a result, changes in the fair value are recognized in interest expense immediately.

The fair value of our interest rate derivative transactions is determined based on a discounted cash flow method using contractual terms of the transactions. The floating coupon rate is based on observable rates consistent with the frequency of the interest cash flows.We have elected to present our interest rate derivatives net on the balance sheets. There was no effect of offsetting on the balance sheets as of September 30, 2015 or December 31, 2014.

The fair values of our interest rate derivatives were as follows (in thousands):

| | Significant Other Observable Inputs (Level 2) Fair Value Measurement as of | |
|---|---|---|
| | September 30, 2015 | December 31, 2014 |
| Current interest rate derivative assets | $ 6 | $ 27 |
| Non-current interest rate derivative assets | 3 | 27 |
| Current interest rate derivative (liabilities) | (293) | (175) |
| Non-current interest rate derivative (liabilities) | (38) | (39) |
| Total interest rate derivatives | $ (322) | $ (160) |

The realized and unrealized amounts recognized in interest expense associated with derivatives that are not designated as hedging instruments were as follows (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Unrealized gain (loss) on interest rate derivatives | $(53) | $21 | $(163) | $201 |
| Realized gain (loss) on interest rate derivatives | (100) | 74 | (357) | 127 |

Commodity Swaps

In our normal course of business, periodically we enter into month-ahead swap contracts to hedge our exposure to certain intra-month natural gas index pricing risk. The total volume of outstanding month-ahead swap contracts as of September 30, 2015 and December 31, 2014 was 10,000 and 12,000 MMBtu per day, respectively. We define these contracts as Level 2 because the index price associated with such contracts is observable and tied to a similarly quoted first-of-the-month natural gas index price.

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We have elected to present our commodity swaps net on the balance sheets. We did not have any cash collateral received or paid on our commodity swaps as of September 30, 2015 or December 31, 2014. The effect of offsetting on our balance sheets was as follows (in thousands):

| | September 30, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| | Other Current Assets | Other Current Liabilities | Other Current Assets | Other Current Liabilities |
| Gross amounts of recognized assets | $— | $— | $112 | $— |
| Gross amounts offset on the balance sheets | — | — | — | — |
| Net amount | $— | $— | $112 | $— |

The realized and unrealized gain/loss on these derivatives, recognized in revenues in our statements of operations, was as follows (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Realized gain (loss) on commodity swap derivatives | $11 | $213 | $147 | $(875) |
| Unrealized gain (loss) on commodity swap derivatives | (15) | (207) | (126) | (338) |

5. LONG-LIVED ASSETS

Property, Plant and Equipment

Property, plant and equipment consisted of the following (in thousands):

| | Estimated Useful Life (yrs) | September 30, 2015 | December 31, 2014 |
|---|---|---|---|
| Pipelines | 15-30 | $540,061 | $488,592 |
| Gas processing, treating and other plants | 15 | 545,439 | 515,080 |
| Compressors | 7-15 | 69,131 | 62,741 |
| Rights of way and easements | 15 | 46,358 | 37,238 |
| Furniture, fixtures and equipment | 5 | 10,792 | 3,671 |
| Capital lease vehicles | 3-5 | 2,442 | 2,076 |
| Total property, plant and equipment | | 1,214,223 | 1,109,398 |
| Accumulated depreciation and amortization | | (194,648) | (142,234) |
| Total | | 1,019,575 | 967,164 |
| Construction in progress | | 29,698 | 63,858 |
| Land and other | | 25,391 | 27,548 |
| Property, plant and equipment, net | | $1,074,664 | $1,058,570 |

Depreciation is provided using the straight-line method based on the estimated useful life of each asset.

In January 2015, we shut down our Gregory facility for four weeks due to a fire at the facility. We reached our insurance deductible as part of efforts to return the facility to service from the fire and recorded a receivable in our condensed consolidated balance sheets as of September 30, 2015 for amounts incurred above the deductible.

Intangible Assets

Intangible assets of $1.5 million as of September 30, 2015 and December 31, 2014, respectively, represent the unamortized value assigned to long-term supply and gathering contracts acquired in 2011. These intangible assets are amortized on a straight-line basis over the 30-year expected useful lives of the contracts through 2041. Amortization expense over the next five years related to intangible assets is not significant.

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## 6. LONG-TERM DEBT

Our outstanding debt and related information at September 30, 2015 and December 31, 2014 are as follows (in thousands):

| | September 30, 2015 | December 31, 2014 |
|---|---|---|
| Revolving credit facility due 2019 | $135,000 | $30,000 |
| Term loans (including OID of $1.9 million) due 2021 | 442,507 | 445,629 |
| Total long-term debt (including current portion) | 577,507 | 475,629 |
| Current portion of long-term debt | $(4,500) | $(4,500) |
| Total long-term debt | $573,007 | $471,129 |
| Outstanding letters of credit | $22,110 | $30,130 |
| Remaining unused borrowings | $42,890 | $139,870 |

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Weighted average interest rate | 5.19 % | 4.80 % | 5.15 % | 4.20 % |
| Average outstanding borrowings | $585,283 | $372,072 | $549,342 | $252,005 |
| Maximum borrowings | $596,500 | $465,000 | $596,500 | $465,000 |

### Previous Credit Facility

In November 2012, we entered into a five-year $350.0 million revolving credit facility (as amended, the “Previous Credit Facility”). Borrowings under the Previous Credit Facility were set to mature in November 2017. We utilized the Previous Credit Facility for working capital requirements and capital expenditures, the purchase of assets, the payment of distributions and other general purposes. During 2013 and the first quarter of 2014, we entered into a total of four amendments to the Previous Credit Facility. In connection with these amendments, our availability was reduced from $350.0 million to the sum of $250.0 million plus any amounts placed on deposit in a collateral account of our General Partner and letters of credit outstanding. This availability was increased to $350.0 million in connection with the fourth amendment in March 2014. In connection with the closing of the TexStar Rich Gas System Transaction, we refinanced our Previous Credit Facility and entered into the Senior Credit Facilities (as defined below).

### Senior Credit Facilities

On August 4, 2014, in connection with the consummation of the Contribution and TexStar Rich Gas System Transaction, we entered into (a) the Third A&R Revolving Credit Agreement (as defined in Note 1) and (b) a Term Loan Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, and a syndicate of lenders (the “Term Loan Agreement” and, together with the Third A&R Revolving Credit Agreement, the “Senior Credit Facilities”). The initial borrowings and extensions of credit under the Term Loan Agreement were used to finance the TexStar Rich Gas System Transaction (including the immediate repayment of the $100 million of debt assumed in the transaction), the repayment of certain of our existing debt and the payment of fees and expenses in connection with the new debt arrangements and ongoing working capital and other general partnership purposes. No amounts were drawn initially on the Third A&R Revolving Credit Agreement. Substantially all of our assets are pledged as collateral under the Senior Credit Facilities, with the security interest of the facilities ranking pari passu.

### Third A&R Revolving Credit Agreement

The Third A&R Revolving Credit Agreement is a five-year $200 million revolving credit facility (the “Credit Facility”). Borrowings under our Credit Facility bear interest at the LIBOR plus an applicable margin or a base rate as defined in the respective credit agreement. Pursuant to the Third A&R Revolving Credit Agreement, among other things:

(a) the letters of credit sublimit increased to $75 million;

(b) we have the right to increase the total commitments under the Credit Facility by obtaining additional commitments from other lenders, as long as our senior secured leverage ratio is less than or equal to 4.50 to 1.00 before and after giving effect to such increase, subject to certain other conditions;

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(c) the definition of "Change of Control" is amended to permit the combination transaction with TexStar and to reflect the Sponsors' control of the General Partner;

(d) our maximum consolidated total leverage ratio (i) was set at 5.75 to 1.00 as of the last day of the fiscal quarter ending each of September 30, 2014 and December 31, 2014, (ii) 5.50 to 1.00 as of the last day of the fiscal quarter ending March 31, 2015, (iii) 5.25 to 1.00 as of the last day of the fiscal quarter ending June 30, 2015 and (iv) 5.00 to 1.00 as of the last day of each fiscal quarter thereafter;

(e) we had the right, exercisable on or before the date that our annual audited financial statements were due for the 2014 fiscal year, to comply with the consolidated total leverage ratio, consolidated senior secured leverage ratio and the consolidated interest coverage ratio covenants (the "Financial Covenants") by applying certain specified quarterly base periods and annualization methods pertaining to the TexStar Rich Gas System;

(f) if we fail to comply with the Financial Covenants (a "Financial Covenant Default"), we have the right (which cannot be exercised more than two times in any twelve month period or more than four times during the term of the facility) to cure such Financial Covenant Default by having the Sponsors purchase equity interests in or make capital contributions to us resulting in, among other things, proceeds that, if added to consolidated EBITDA, as defined in the Third A&R Revolving Credit Agreement, would result in us satisfying the Financial Covenants;

(g) certain definitions are amended to take into account the TexStar Rich Gas System; and

(h) the negative covenants are amended to permit the entry into, and indebtedness under, the Term Loan Agreement.

Amendment to Third A&R Revolving Credit Agreement

During the fourth quarter of 2014 and into the first quarter of 2015, as a result of the decline in commodity prices and associated decline in upstream drilling activity, we experienced a decline in the growth in volume of natural gas we gather and process for our customers. Our results in the first quarter of 2015 also were negatively impacted by the fire at our Gregory facility (see Note 5). These collective events impacted our operating results adversely and resulted in the need to amend our Third A&R Revolving Credit Agreement.

On May 7, 2015, we entered into the First Amendment to our Third A&R Revolving Credit Agreement among the Partnership, as the borrower, Wells Fargo, N.A., as the administrative agent, the lenders and other parties thereto (the "Credit Agreement Amendment").

The Credit Agreement Amendment, among other things:

(a) (i) revised the maximum consolidated total leverage ratio set at 5.75 to 1.0 as of the last day of the fiscal quarter ending each of March 31, 2015, June 30, 2015 and September 30, 2015, (ii) 5.5 to 1.0 as of the last day of the fiscal quarter ending each of December 31, 2015, March 31, 2016 and June 30, 2016, (iii) 5.25 to 1.0 as of the last day of the fiscal quarter ending September 30, 2016, and (iv) 5.00 to 1.0 as of the last day of each fiscal quarter thereafter, in each case, without any step-ups in connection with acquisitions;

(b) increased the applicable margins used in connection with the loans and the commitment fee so that the applicable margin for Eurodollar Loans (as used in the Third A&R Revolving Credit Agreement) ranges from 2.00% to 4.50%, the applicable margin for base rate loans ranges from 1.00% to 3.50% and the applicable rate for commitment fees ranges from 0.375% to 0.500%;

(c) permits the Partnership to comply with certain Financial Covenants by making certain pro forma adjustments with respect to minimum revenues to be received from Frio;

(d) modified our ability to cure Financial Covenant defaults;

(e) imposed additional restrictions on our ability to declare and pay quarterly cash distributions with respect to our subordinated units;

(f) amended certain other provisions of the Third A&R Revolving Credit Agreement as more specifically set forth in the Credit Agreement Amendment; and

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(g) allows us an unlimited number of quarterly equity cures related to our Financial Covenant Default through the fourth quarter of 2016, and no more than two in a twelve month period thereafter for the life of the agreement. Additionally, we are unable to borrow on our Credit Facility until we have funded the required equity cure for the third quarter of 2015; however, we retain the ability to fund the required equity cure using a contractual non-cash credit amount of up to $13 million, $4.7 million of which was used to fund an equity cure in order to stay in compliance with the consolidated total leverage ratio for our Financial Covenants as of June 30, 2015.

Term Loan Agreement

The Term Loan Agreement is a seven-year $450 million senior secured term loan facility. On August 4, 2014, the lenders funded the full amount of the facility. Borrowings under our Term Loan Agreement bear interest at LIBOR plus 4.25% or a base rate as defined in the respective credit agreement with a LIBOR floor of 1.00%. Under the Term Loan Agreement, among other things:

(a) subject to certain requirements, including the absence of a default and pro forma compliance under the Third A&R Revolving Credit Agreement and pro forma compliance with a senior secured leverage ratio less than or equal to 4.50 to 1.00 before and after giving effect to such increase, we may from time to time request incremental term loan commitments subject to certain other conditions;

(b) we may seek commitments from third party lenders in connection with any incremental term loan commitment requests, subject to certain consent rights given to the administrative agent;

(c) the guarantors and the collateral are the same as provided for the benefits of the lenders in the Third A&R Revolving Credit Agreement;

(d) subject to certain conditions, we may request that the lenders extend the seven-year maturity of all or a portion of the outstanding loans under the facility;

(e) the facility is amortized in equal quarterly installments in an aggregate annual amount equal to 1% of the original principal amount of the initial loan ($1.125 million), with the remainder due on the maturity date;

(f) there are customary mandatory prepayment provisions and, subject to certain conditions, permissive prepayment provisions; provided, that if certain repricing transactions occur, we must pay a call premium equal to 1% of the principal amount of the loans subject to the repricing transactions; and

(g) there are customary representations and warranties, affirmative covenants, negative covenants and provisions governing an event of default (including acceleration of payment in connection with material indebtedness, including the Third A&R Revolving Credit Agreement).

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## 7. COMMITMENTS AND CONTINGENCIES

### Legal Matters

On March 5, 2013, one of our subsidiaries, Southcross Marketing Company Ltd., filed suit in a District Court of Dallas County, Texas, against Formosa Hydrocarbons Company, Inc. (“Formosa”). The lawsuit sought recoveries of losses that we believe our subsidiary experienced as a result of the failure of Formosa to perform certain obligations under the gas processing and sales contract between the parties. Formosa filed a response generally denying our claims and, later, Formosa filed a counterclaim against our subsidiary claiming our subsidiary breached the gas processing and sales contract and a related agreement between the parties for the supply by Formosa of residue gas to a third party on behalf of our subsidiary. After a bench trial held in January 2015, on February 5, 2015, the judge ruled that Formosa breached certain of its obligations under the gas processing and sales contract and that our subsidiary breached an obligation under each of the gas processing and sales contract and the related residue gas agreement. The amount of damages awarded to our subsidiary was in excess of the damages awarded to Formosa. Rather than wait for the judge to award attorneys’ fees for each party as to the claims on which it prevailed, the parties have reached an agreement as to the appropriate award of attorneys’ fees. The amount of attorneys’ fees to be paid to our subsidiary is in excess of the attorneys’ fees to be paid to Formosa. After the ruling, our subsidiary filed a motion for reconsideration regarding a claim that was dismissed before trial through summary judgment. Formosa filed its own motion for reconsideration regarding the amount of damages awarded to our subsidiary on one of its claims. A hearing on both motions for reconsideration was held on June 5, 2015. The judge has yet to issue a ruling on these motions. Even if Formosa is successful in its request to reduce the damages awarded to our subsidiary, the amount of damages awarded to our subsidiary would still be in excess of the damages awarded to Formosa. No judgment will be entered until the judge has made a ruling on these motions. Regardless of how the judge rules on these motions, the judgment is not expected to have a material impact on our results of operations, cash flows or financial condition.

From time to time, we are party to certain legal or administrative proceedings that arise in the ordinary course and are incidental to our business. For example, during periods when we are expanding our operations through the development of new pipelines or the construction of new plants, we may become involved in disputes with landowners that are in close proximity to our activities. While we are currently involved in several such proceedings and disputes, our management believes that none of such proceedings or disputes will have a material adverse effect on our results of operations, cash flows or financial condition. However, future events or circumstances, currently unknown to management, will determine whether the resolution of any litigation or claims ultimately will have a material effect on our results of operations, cash flows or financial condition in any future reporting periods.

### Regulatory Compliance

In the ordinary course of our business, we are subject to various laws and regulations. In the opinion of our management, compliance with current laws and regulations will not have a material effect on our results of operations, cash flows or financial condition.

### Leases

#### Capital Leases

We have auto leases that are classified as capital leases. The termination dates of the lease agreements vary from 2015 to 2019. We recorded amortization expense related to the capital leases of $0.1 million and $0.4 million for the three and nine months ended September 30, 2015, respectively, and $0.1 million and $0.4 million for the three and nine months ended September 30, 2014, respectively. Capital leases entered into during the three and nine months ended September 30, 2015 were less than $0.1 million and $0.4 million, respectively. Capital leases entered into during the three and nine months ended September 30, 2014 were $0.1 million and $0.6 million, respectively. The capital lease obligation amounts included on the balance sheets were as follows (in thousands):

| | September 30, 2015 | December 31, 2014 |
|---|---|---|
| Other current liabilities | $404 | $455 |
| Other non-current liabilities | 602 | 578 |
| Total | $1,006 | $1,033 |

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Operating Leases

We maintain operating leases in the ordinary course of our business activities. These leases include those for office and other operating facilities and equipment. The termination dates of the lease agreements vary from 2015 to 2025. Expenses associated with operating leases, which are recorded in operations and maintenance expenses and general and administrative expenses in our statements of operations, were $1.9 million and $3.7 million for the three and nine months ended September 30, 2015, respectively. A rental reimbursement included in our lease agreement associated with the office space we leased in June 2015 of $2.3 million has been recorded as a deferred liability on our condensed consolidated balance sheets as of September 30, 2015. This amount will be amortized against the lease payments over the length of the lease term. Expenses associated with operating leases were $0.6 million and $1.2 million for the three and nine months ended September 30, 2014, respectively.

Purchase Commitments

At September 30, 2015, we had commitments of approximately $11.7 million primarily related to the purchase of pipelines and compressors for our various capital expansion projects. We have other planned capital projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures.

8. SERIES A PREFERRED UNITS

During the second quarter of 2013, we entered into a Series A Convertible Preferred Unit Purchase Agreement with Southcross Energy LLC, pursuant to which we issued and sold 1,715,000 Series A Preferred Units to Southcross Energy LLC for a cash purchase price of $22.86 per unit, in a privately negotiated transaction (the “Private Placement”). Southcross Energy LLC sold 1,500,000 of these Series A Preferred Units to third parties during the second quarter of 2013.

All of the Series A Preferred Units, including units held by Southcross Energy LLC, were converted to common units on August 4, 2014 in connection with the Holdings Transaction. See Notes 1 and 9.

9. PARTNERS’ CAPITAL

Ownership

Our units outstanding as of September 30, 2015 are as follows (in units):

| | | Owned by Parent | | | |
|---|---|---|---|---|---|
| | Partners’ Capital | | | | |
| | Public Common | Common | Class B Convertible | Subordinated | General Partner |
| Units outstanding as of December 31, 2014 | 21,684,543 | 2,116,400 | 14,889,078 | 12,213,713 | 1,038,852 |
| Vesting of LTIP units, net | 100,028 | — | — | — | — |
| In-kind distributions and issuances to general partner to maintain 2.0% ownership | — | — | 795,434 | — | 108,998 |
| Common unit issuance related to the 2015 Holdings Acquisition | — | 4,500,000 | — | — | — |
| Board of Director grants | 17,185 | — | — | — | — |
| | 21,801,756 | 6,616,400 | 15,684,512 | 12,213,713 | 1,147,850 |

Units outstanding as of September 30, 2015

Common Units

Our common units represent limited partner interests in us. The holders of our common units are entitled to participate in partnership distributions and are entitled to exercise the rights and privileges available to limited partners under our Partnership Agreement.

In February 2014, we completed a public equity offering of 9,200,000 additional common units and we received a capital contribution from our General Partner to maintain its 2.0% interest in us. The proceeds from the public offering were $144.7 million before expenses of $0.4 million related to the offering. The net proceeds from the offering were used for our Onyx acquisition in March 2014, to fund the construction of our pipeline system extending into Webb County, Texas and for general partnership purposes.

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In connection with the TexStar Rich Gas System Transaction and the Holdings Transaction on August 4, 2014, we issued Class B Convertible Units, accelerated the vesting of awards under our LTIP (see Note 11), and all of the holders of our Series A Preferred Units elected to convert their Series A Preferred Units into common units based on an exchange ratio of 110%.
On May 7, 2015, we completed the 2015 Holdings Acquisition for total consideration of $77.6 million, consisting of $15.0 million in cash and 4.5 million new common units, valued as of the date of closing and issued to Holdings.
Class B Convertible Units

In connection with the TexStar Rich Gas System Transaction, on August 4, 2014, we established our Class B Convertible Units. The Class B Convertible Units consist of 14,633,000 of such units plus any additional Class B PIK Units. The Class B Convertible Units have the same rights, preferences and privileges, and are subject to the same duties and obligations, as our common units, with certain exceptions as noted below.

Our Partnership Agreement does not allow additional Class B Convertible Units (other than Class B PIK Units) to be issued without the prior approval of our General Partner and the holders of a majority of the outstanding Class B Convertible Units. As of September 30, 2015, 100% of our outstanding Class B Convertible Units were indirectly owned by Holdings.

Distribution Rights: Commencing with the third quarter of 2014 and until converted, as long as certain requirements are met, the holders of the Class B Convertible Units will receive quarterly distributions in an amount equal to $0.3257 per unit paid in Class B PIK Units (based on a unit issuance price of $18.61) within 45 days after the end of each quarter. Our General Partner was entitled, and has exercised its right, to retain its 2.0% general partner interest in us in connection with the original issuance of Class B Convertible Units. In connection with future distributions of Class B PIK Units, the General Partner is entitled to a corresponding distribution to maintain its 2.0% general partner interest in us.

Conversion Rights: The Class B Convertible Units are convertible into common units on a one-for-one basis and, once converted, will participate in cash distributions pari passu with all other common units. The conversion of Class B Convertible Units will occur on the date we (a) make a quarterly distribution equal to or greater than $0.44 per common unit, (b) generate Class B Distributable Cash Flow (as defined in our Partnership Agreement) in an amount sufficient to pay the declared distribution on all units for the two quarters immediately preceding the date of conversion (the "measurement period") and (c) forecast paying a distribution equal to or greater than $0.44 per unit from forecasted Class B Distributable Cash Flow on all outstanding common units for the two quarters immediately following the measurement period.

Voting Rights: The Class B Convertible Units generally have the same voting rights as common units, and have one vote for each common unit into which such units are convertible.

Changes in Partners' Capital due to Holdings Transaction

As discussed in Note 1, on August 4, 2014, Southcross Energy LLC and TexStar combined. As a result of this transaction, Holdings, through a wholly-owned subsidiary, (a) acquired 100% of TexStar and its general partner from BBTS Borrower LP and (b) acquired 2,116,400 of our common units and 12,213,713 of our subordinated units from Southcross Energy LLC. Thus, as a result of that transaction, Holdings acquired an approximate 57.4% limited partner interest in us at that time, as well as 100% of our General Partner, which owns an approximate 2.0% interest in us and our incentive distribution rights. BBTS Borrower LP was controlled by EIG and Tailwater. In December 2014, BBTS Borrower LP distributed to each of EIG and Tailwater, in relatively equal proportions, its interest in Holdings. Southcross Energy LLC is controlled by Charlesbank. The Holdings Transaction resulted in our Sponsors each indirectly owning approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine

Opportunities Fund and GE Energy Financial Services also own certain additional equity interests in Holdings.

Subordinated Units

Subordinated units represent limited partner interests in us and convert to common units at the end of the Subordination Period (as defined in our Partnership Agreement). The principal difference between our common units and our subordinated units is that in any quarter during the Subordination Period, holders of the subordinated units are not entitled to receive any distribution of available cash until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units do not accrue arrearages. Beginning with the third quarter of 2014, until such time we have a Distributable Cash Flow Ratio of at least 1.0, Holdings, the indirect holder of the subordinated units has waived the right to receive distributions on any subordinated units that would cause the Distributable Cash Flow Ratio to be less than 1.0. In addition, the Credit Agreement Amendment imposed additional restrictions on our ability to declare and pay quarterly cash distributions with respect to our subordinated units. See Note 6.

With respect to the fourth quarter of 2014, Holdings also waived the requirement that any distribution owed to it for that quarter be paid within 45 days of the end of the quarter, provided that the distribution was paid before or in conjunction with the filing of our 2014 Annual Report on Form 10-K. We paid a distribution of $0.28 per unit on our 12,213,713 subordinated units in conjunction with the filing of our 2014 Annual Report on Form 10-K.

General Partner Interests

As defined by our Partnership Agreement, general partner units are not considered to be units (common or subordinated), but are representative of our general partner's 2.0% ownership interest in us. Our General Partner has received general partner
unit PIK distributions in connection with the Private Placement (see Note 8) and the Class B Convertible Units. In connection with other equity issuances, including issuances related to the TexStar Rich Gas System Transaction and the Holdings Transaction, our General Partner has made capital contributions in exchange for additional general partner units to maintain its 2.0% ownership interest in us.

Equity Distribution Agreement

On November 12, 2014, we established a $75 million "at-the-market" equity offering program pursuant to an equity distribution agreement (the "Distribution Agreement") with Wells Fargo Securities, LLC, J.P. Morgan Securities LLC and RBC Capital Markets, LLC (each, a "Manager" and, collectively, the "Managers"). Under the Distribution Agreement, we may offer and sell up to $75 million in aggregate gross sales proceeds of our common units (the "Offered Units") from time to time through the Managers, each as our sales agent. Sales of the Offered Units, if any, made under the Distribution Agreement will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices prevailing at the time of sale in block transactions, or as otherwise agreed upon by us and any Manager. The Offered Units have been registered under the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Registration No. 333-192105 declared effective December 10, 2013, including the prospectus contained therein, as supplemented by the prospectus supplement filed with the SEC on November 12, 2014. We intend to use the net proceeds from the sale of the Offered Units, if any, for general partnership purposes, including the repayment of debt, acquisitions and funding capital expenditures. As of September 30, 2015, we have not sold any of the Offered Units pursuant to the Distribution Agreement.

The Distribution Agreement contains customary representations, warranties and agreements by us, including our obligations to indemnify the Managers for certain liabilities under the Securities Act. The Managers and certain of their affiliates have engaged, and may in the future engage, in commercial and investment banking transactions with us in the ordinary course of their business for which they have received, and expect to receive, customary compensation and expense reimbursement. In particular, affiliates of each of the Managers are lenders under our Senior Credit Facilities, an affiliate of Wells Fargo Securities, LLC is a lender under our Term Loan Agreement, and affiliates of the other sales agents may from time to time hold positions under the Term Loan Agreement. If we use any net proceeds of this offering to repay borrowings under our Senior Credit Facilities, such affiliates of the

Managers will receive proceeds of the offering.

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10. TRANSACTIONS WITH RELATED PARTIES

Charlesbank, EIG & Tailwater (our Sponsors)

Effective August 4, 2014, in connection with the Contribution and as a result of the Holdings Transaction, the board of directors of our General Partner includes one director affiliated with Charlesbank, one director affiliated with EIG, one director affiliated with Tailwater and three outside directors. On July 15, 2015, a fourth outside director was elected to serve on the board of directors of our General Partner. The eighth member of the board of directors of our General Partner, and its chairman, is David W. Biegler. Mr. Biegler will serve as chairman until the earlier of August 4, 2016 and his death or resignation. Our non-employee directors are reimbursed for certain expenses incurred for their services to us. The director services fees and expenses are included in general and administrative expenses in our statements of operations. We incurred fees and expenses related to the services from our affiliated directors as follows (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Charlesbank | $36 | $80 | $116 | $270 |
| EIG | 16 | 8 | 48 | 8 |
| Tailwater | 16 | 8 | 48 | 8 |
| Total fees and expenses paid for director services to affiliated entities | $68 | $96 | $212 | $286 |

Southcross Energy Partners GP, LLC (our General Partner)

Our General Partner does not receive a management fee or other compensation for its management of us. However, our General Partner and its affiliates are entitled to reimbursements for all expenses incurred on our behalf, including, among other items, compensation expense for all employees required to manage and operate our business. We incurred expenses related to these reimbursements as follows (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Reimbursements included in general and administrative expenses | $2,715 | $3,076 | $9,794 | $9,057 |
| Reimbursements included in operations and maintenance expenses | 4,335 | 4,562 | 14,767 | 12,175 |
| Total reimbursements to our General Partner and its affiliates | $7,050 | $7,638 | $24,561 | $21,232 |

Compensation expense for services incurred by us on behalf of Southcross Energy LLC was billed to Southcross Energy LLC. For the three and nine months ended September 30, 2015, compensation expense, which was not incurred on our behalf, of $0.1 million and $0.5 million, respectively, was billed to Southcross Energy LLC. For the three and nine months ended September 30, 2014, $0.4 million and $0.7 million, respectively, was incurred by us and billed to Southcross Energy LLC.

Wells Fargo Bank, N.A.

Under our Senior Credit Facilities, Wells Fargo Bank, N.A. serves as the administrative agent (and served in that same capacity under our Previous Credit Facility). See Note 6. An affiliate of Wells Fargo Bank, N.A. is a member of our investor group. We entered into amendments to our Previous Credit Facility during 2013 and 2014. In addition, in connection with the TexStar Rich Gas System Transaction, during the third quarter of 2014, we entered into the Senior Credit Facilities, which include syndicates of financial institutions and other lenders. Affiliates of Wells Fargo

Bank, N.A. have from time to time engaged in commercial banking and financial advisory transactions with us in the normal course of business. For each of the three and nine months ended September 30, 2015 we incurred costs, excluding interest, to Wells Fargo Bank, N.A. and its affiliates of $0.3 million and $1.0 million, respectively, compared to $8.9 million and $9.1 million, respectively, for each of the three and nine months ended September 30, 2014.

Other Transactions with Affiliates

Under the Distribution Agreement, we made customary representations, warranties and agreements, including an agreement to indemnify the Managers for certain liabilities under the Securities Act. The Managers and certain of their affiliates
have engaged, and may in the future engage, in commercial and investment banking transactions with us in the ordinary course

of their business for which they have received, and expect to receive, customary compensation and expense reimbursement. In particular, affiliates of each of the Managers are lenders under our Senior Credit Facilities, an affiliate of Wells Fargo Securities, LLC is a lender under our Senior Credit Facilities and affiliates of the other sales agents may from time to time hold positions under the Term Loan Agreement. If we use any net proceeds of this offering to repay borrowings under our Senior Credit Facilities, such affiliates of the Managers will receive proceeds of the offering.

In conjunction with the TexStar Rich Gas System Transaction, we entered into a gas gathering and processing agreement (the "G&P Agreement") and an NGL sales agreement (the "NGL Agreement") with an affiliate of Holdings. Under the terms of these agreements, we transport, process and sell rich natural gas for the affiliate of Holdings in return for fees that are substantially equivalent to the fees that Holdings receives from its customers for such services, and we can sell natural gas liquids that we own to Holdings at prices that are substantially equivalent to prices that Holdings receives from third parties. The NGL Agreement also permits us to utilize Holdings' fractionation services at market-based rates.

In conjunction with the 2015 Holdings Acquisition, we entered into a series of commercial agreements with affiliates of Holdings including a gas gathering and treating agreement, a compression services agreement, a repair and maintenance agreement and an NGL transportation agreement. Under the terms of these commercial agreements, we gather, treat, transport, compress and redeliver natural gas for the affiliates of Holdings in return for agreed-upon fixed fees. In addition, under the NGL transportation agreement, we transport a minimum volume of NGLs per day at a fixed rate per gallon. The operational expense associated with such agreements has been capped at $1.7 million per quarter. In the third quarter of 2015, we exceeded this cap by $0.5 million which was recorded as a receivable from Holdings on our condensed consolidated balance sheets.

During the three and nine months ended September 30, 2015, the Partnership recorded revenues from affiliates of $32.5 million and $61.0 million, respectively, compared to $6.3 million for the three and nine months ended September 30, 2014 in accordance with the G&P Agreement, the NGL Agreement and the commercial agreements entered into in connection with the 2015 Holdings Acquisition.

We had accounts receivable due from affiliates of $32.7 million and $11.3 million as of September 30, 2015 and December 31, 2014, respectively, and accounts payable due to affiliates of $5.3 million and $12.9 million as of September 30, 2015 and December 31, 2014, respectively. The affiliate receivable and payable balances are related primarily to transactions associated with Holdings, noted above, and our joint venture investments (defined in Note 13).

## 11. INCENTIVE COMPENSATION

### Unit Based Compensation

### Long-Term Incentive Plan

On November 7, 2012, and in connection with our initial public offering, we established the 2012 Long-Term Incentive Plan ("LTIP"), which provides incentive awards to eligible officers, employees and directors of our General Partner. Awards granted to employees under the LTIP vest over a three-year period in equal annual installments or in the event of a change in control of our General Partner in either a common unit or an amount of cash equal to the fair market value of a common unit at the time of vesting, as determined by management at its discretion. These awards also include distribution equivalent rights that grant the holder the right to receive an amount equal to the cash distributions on common units during the period the award remains outstanding.

The following table summarizes information regarding awards of units granted under the LTIP:

| | Units | Weighted-Average Fair Value at Grant Date |
|---|---|---|

| | | |
|---|---|---|
| Unvested - December 31, 2014 | 470,750 | $ 20.45 |
| Granted units | 491,833 | $ 13.22 |
| Forfeited units | (186,241 ) | $ 18.90 |
| Units recaptured for tax withholdings | (46,557 ) | $ 8.48 |
| Vested units | (122,578 ) | $ 10.41 |
| Unvested - September 30, 2015 | 607,207 | $ 16.99 |

For the nine months ended September 30, 2015 and 2014, we granted awards under the LTIP with a grant date fair value of $6.5 million and $15.4 million, respectively, which we have classified as equity awards. As of September 30, 2015 and 2014, we had total unamortized compensation expense of $8.4 million and $9.7 million, respectively, related to unvested awards.

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Compensation expense associated with awards granted in the nine months ended September 30, 2015 of 84,423 units are expected to be recognized over a one-year vesting period, while the remaining awards are expected to be recognized over the three-year vesting period from each equity award's grant date. As of September 30, 2015 and 2014, we had 641,249 and 909,934 units, respectively, available for issuance under the LTIP.

A grant of 84,423 units was made to the officers of our General Partner on March 10, 2015 that have a one-year vesting period rather than a three-year vesting period. These executive awards were not compensation earned for performance in 2014.

Unit Based Compensation Expense

The following table summarizes information regarding recognized compensation expense, which is included in general and administrative and operations and maintenance expense on our statements of operations (in thousands):

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2015 | 2014 | | 2015 | 2014 | |
| Unit-based compensation | $1,038 | $9,227 | (1) | $3,513 | $10,837 | (1) |

(1) This amount includes $7.1 million related to the accelerated vesting of the LTIP awards and $1.5 million related to the vesting of the Southcross Energy LLC equity equivalent units as a result of the change in control that took place on August 4, 2014.

Accelerated Vesting of Common Units

In conjunction with the departure of our Chief Financial Officer in the second quarter of 2015, 38,997 outstanding phantom units granted to him under the LTIP vested (and certain accumulated distribution equivalent rights were paid), pursuant to a general release agreement. The Partnership recognized $0.5 million in general and administrative expenses in the condensed consolidated statements of operations for the nine months ended September 30, 2015 in connection with the accelerated vesting of these units.

Employee Savings Plan

We have employee savings plans under Sections 401(a) and 401(k) of the Internal Revenue Code of 1986, as amended, whereby employees of our General Partner may contribute a portion of their base compensation to the employee savings plan, subject to limits. We provide a matching contribution each payroll period equal to 100% of each employee's contribution up to the lesser of 6% of the employee's eligible compensation or $18,000 annually for the period. The following table summarizes information regarding contributions and the expense recognized for the matching contributions, which is included in general and administrative expense on our statements of operations (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Matching contributions expensed for employee savings plan | $180 | $271 | $519 | $861 |

2014 Incentive Plan

On August 4, 2014, our General Partner and Southcross GP Management Holdings, LLC, a Delaware limited liability company of which Holdings is the sole managing member ("GP Management"), adopted the Southcross Energy Partners GP, LLC and Southcross GP Management Holdings, LLC 2014 Equity Incentive Plan (the "2014 Incentive Plan"). Under the 2014 Incentive Plan, employees, consultants and directors of our General Partner and GP Management will be eligible to receive incentive compensation awards.

The 2014 Incentive Plan generally provides for the grant of awards, from time to time at the discretion of the board of directors of our General Partner (and, as applicable, the board of directors of the general partner of Holdings), of non-voting units in our General Partner to GP Management and then a corresponding grant or award of non-voting units of GP Management to the employee, consultant or director.

In connection with the adoption of the 2014 Incentive Plan, our General Partner amended and restated its limited liability company agreement and entered into its Second Amended and Restated Limited Liability Company Agreement which establishes a new class of non-voting units for issuance pursuant to the 2014 Incentive Plan and designates Southcross Holdings

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Borrower LP, a wholly owned subsidiary of Holdings as our General Partner's managing member. As of September 30, 2015, no awards had been granted under this plan.

12. REVENUES

We had revenues consisting of the following categories (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Sales of natural gas | $104,050 | $123,874 | $309,355 | $392,633 |
| Sales of NGLs and condensate | 38,704 | 65,046 | 115,314 | 171,201 |
| Transportation, gathering and processing fees | 35,130 | 23,651 | 104,006 | 57,045 |
| Other | 1,685 | 107 | 4,053 | 453 |
| Total revenues | $179,569 | $212,678 | $532,728 | $621,332 |

13. INVESTMENTS IN JOINT VENTURES

Assets acquired through the TexStar Rich Gas System Transaction include equity interests in three joint ventures. During 2012, a subsidiary of TexStar and a company subsequently acquired by Atlas Pipeline Partners, L.P. ("Atlas") formed T2 Eagle Ford Gathering Company LLC ("T2 Eagle Ford"), T2 LaSalle Gathering Company LLC ("T2 LaSalle") and T2 EF Cogeneration Holdings LLC ("T2 Cogen") to construct and operate pipelines and a cogeneration facility located in South Texas. During 2015, Atlas was acquired by Targa, which is now our joint venture partner. We indirectly own a 50% interest in T2 Eagle Ford, a 50% interest in T2 Cogen and a 25% interest in T2 LaSalle. We pay our proportionate share of the joint ventures' operating costs, excluding depreciation and amortization, through lease capacity payments. As a result, our share of the joint ventures' losses is related primarily to the joint ventures' depreciation and amortization. The joint ventures' summarized financial data from their statements of operations for the three and nine months ended September 30, 2015 and 2014 is as follows (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Revenue | | | | |
| T2 Eagle Ford | $1,215 | $516 | $3,351 | $516 |
| T2 Cogen | 1,218 | 410 | 4,067 | 410 |
| T2 LaSalle | 450 | 229 | 1,279 | 229 |
| | | | | |
| Net loss | | | | |
| T2 Eagle Ford | $(4,977) | $(3,234) | $(14,952) | $(3,234) |
| T2 Cogen | (1,447) | (2,871) | (4,300) | (2,871) |
| T2 LaSalle | (1,419) | (1,021) | (4,384) | (1,021) |

Our equity in losses of joint venture investments is comprised of the following for the three and nine months ended September 30, 2015 and 2014 (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| T2 Eagle Ford | $(2,489) | $(1,618) | $(7,476) | $(1,618) |
| T2 Cogen | (723) | (1,435) | (2,150) | (1,435) |
| T2 LaSalle | (355) | (255) | (1,096) | (255) |
| Equity in losses of joint venture investments | $(3,567) | $(3,308) | $(10,722) | $(3,308) |

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Our investments in joint ventures is comprised of the following as of September 30, 2015 and December 31, 2014 (in thousands):

| | September 30, 2015 | December 31, 2014 |
|---|---|---|
| T2 Eagle Ford | $104,172 | $108,185 |
| T2 Cogen | 17,516 | 19,615 |
| T2 LaSalle | 18,285 | 19,298 |
| Investments in joint ventures | $139,973 | $147,098 |

14. CONCENTRATION OF CREDIT RISK

Our primary markets are in South Texas, Alabama and Mississippi. We have a concentration of revenues and trade accounts receivable due from customers engaged in the production, trading, distribution and marketing of natural gas and NGL products. These concentrations of customers may affect overall credit risk in that these customers may be affected similarly by changes in economic, regulatory or other factors. We analyze our customers' historical financial and operational information before extending credit.

Our top ten customers for the three and nine months ended September 30, 2015 and 2014 represent the following percentages of consolidated revenue:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Top ten customers | 50.0 % | 66.9 % | 53.3 % | 67.1 % |

The percentage of total consolidated revenue for each customer that exceeded 10% of total revenues for the three and nine months ended September 30, 2015 and 2014 was as follows:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Sherwin Alumina Company | (a) | (a) | (a) | 10.6 % |
| Trafigura AG | (a) | 15.7 % | (a) | 13.6 % |

(a) Information is not provided for periods for which the customer or producer was less than 10% of our consolidated revenue.

For the nine months ended September 30, 2015 and 2014, we did not experience significant non-payment for services. At September 30, 2015 and December 31, 2014, we did not record an allowance for uncollectible accounts receivable.

15. SUBSEQUENT EVENTS

Partnership Distributions

On October 28, 2015, the board of directors of our General Partner declared a cash distribution of $0.40 per common unit and general partnership unit, and also declared a $0.3257 per unit distribution, in the form of additional Class B Convertible Units, on our Class B Convertible Units, which will be paid on November 13, 2015 to unitholders of record on November 9, 2015.

On October 28, 2015, the board of directors of our General Partner authorized an additional 4.5 million additional common units under the LTIP to provide for grants over the next three-year period.

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## 16. SUPPLEMENTAL INFORMATION

Supplemental Cash Flow Information (in thousands)

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2015 | 2014 |
| Supplemental Disclosures: | | |
| Cash paid for interest, net of amounts capitalized | $22,364 | $8,628 |
| Cash received for tax refunds | 58 | 205 |
| Supplemental disclosures of non-cash investing and financing activities: | | |
| Accounts payable related to capital expenditures | 8,133 | 23,144 |
| Change in value recognized in other comprehensive loss | — | 11 |
| Capital lease obligations | 378 | 577 |
| Accrued distribution equivalent rights on LTIP units | 685 | 562 |
| Class B Convertible unit in-kind distributions | 8,059 | — |
| Class B Convertible unit issuance, net | — | 324,413 |
| Consideration paid in excess of purchase price for the TexStar Rich Gas System | — | 98,625 |
| Series A convertible preferred unit in-kind distribution and fair value adjustment | — | 5,130 |
| Net assets contributed in Holdings drop-down acquisition in excess of consideration paid | 29,100 | — |
| Valley Wells' operating expense cap adjustment | 505 | — |
| Purchase of assets in Holdings drop-down acquisition | 62,640 | — |
| Net liabilities assumed by Holdings in Holdings drop-down acquisition | 820 | — |

Capitalization of Interest Cost

We capitalize interest on projects during their construction period. Once a project is placed in service, capitalized interest, as a component of the total cost of the construction, is depreciated over the estimated useful life of the asset constructed. We incurred the following interest costs (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Total interest costs | $9,170 | $6,088 | $25,629 | $11,385 |
| Capitalized interest included in property, plant and equipment, net | (482) | (1,492) | (1,542) | (2,045) |
| Interest expense | $8,688 | $4,596 | $24,087 | $9,340 |

Deferred Financing Costs

Deferred financing costs are capitalized and amortized as interest expense under the effective interest method over the term of the related debt. The unamortized balance of deferred financing costs is included in other assets on the balance sheets. Changes in deferred financing costs are as follows (in thousands):

| | 2015 | 2014 |
|---|---|---|
| Deferred financing costs, January 1 | $16,602 | $5,237 |
| Capitalization of deferred financing costs [(1)] | 685 | 17,716 |
| Amortization of deferred financing costs | (2,362) | (3,596) [(2)] |
| Deferred financing costs, September 30 | $14,925 | $19,357 |

(1) See Note 6.
(2) This amount includes $2.3 million written off in connection with exiting the Previous Credit Facility and entering into the Senior Credit Facilities in August 2014.

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Southcross Assets Considered Leases to Third Parties

In connection with the Onyx acquisition in March 2014, we acquired natural gas pipelines and contracts related to the acquired pipelines (see Note 2). The pipelines transport natural gas to two power plants in Nueces County, Texas under fixed-fee contracts. The contracts have a primary term through 2029 and an option to extend the agreements by an additional term of up to ten years. These contracts are considered operating leases under the applicable accounting guidance.

Future minimum annual demand payment receipts under these agreements as of September 30, 2015 were as follows: $1.4 million for the remainder of 2015; $5.6 million in 2016; $5.6 million in 2017; $2.2 million in 2018; $2.2 million in 2019; and $15.3 million thereafter. The revenue for the demand payments is recognized on a straight-line basis over the term of the contract. The demand fee revenues under the contracts were $0.7 million and $2.0 million for the three and nine months ended September 30, 2015 and $0.7 million and $1.5 million for the three and nine months ended September 30, 2014, respectively, and have been included within transportation, gathering and processing fees within Note 12. These amounts do not include variable fees based on the actual gas volumes delivered under the contracts. Variable fees recognized in revenues within transportation, gathering and processing fees within Note 12 were $0.8 million and $2.3 million for the three and nine months ended September 30, 2015, respectively. Variable fees recognized in revenues within transportation, gathering and processing fees were $0.2 million and $0.6 million for the three and nine months ended September 30, 2014, respectively.

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## Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

### Overview

Southcross Energy Partners, L.P. (the "Partnership," "Southcross," "we," "our" or "us") is a Delaware limited partnership formed in April 2012. Our common units are listed on the New York Stock Exchange under the symbol "SXE."

Until August 4, 2014, Southcross Energy LLC, a Delaware limited liability company, held all of the equity interests in Southcross Energy Partners GP, LLC, a Delaware limited liability company and our general partner ("General Partner"), all of our subordinated units and a portion of our common units. Southcross Energy LLC is controlled through investment funds and entities associated with Charlesbank Capital Partners, LLC ("Charlesbank").

### Recent Developments

#### Holdings Transaction

On August 4, 2014, Southcross Energy LLC and TexStar Midstream Services, LP, a Texas limited partnership ("TexStar"), combined pursuant to a contribution agreement in which Southcross Holdings LP, a Delaware limited partnership ("Holdings"), was formed (the "Holdings Transaction"). As a result of the Holdings Transaction, Holdings indirectly owns 100% of our General Partner (and therefore controls us), all of our subordinated units and a portion of our common units. Our General Partner owns an approximate 2.0% interest in us and all of our incentive distribution rights. Charlesbank, EIG Global Energy Partners, LLC ("EIG") and Tailwater Capital LLC ("Tailwater") (collectively, the "Sponsors") each indirectly own approximately one-third of Holdings. Affiliates of Energy Capital Partners Mezzanine Opportunities Fund and GE Energy Financial Services also own certain additional equity interests in Holdings.

#### TexStar Rich Gas System Transaction

Contemporaneously with the closing of the Holdings Transaction, TexStar contributed to us certain gathering and processing assets (the "TexStar Rich Gas System"), which were owned by TexStar (the "TexStar Rich Gas System Transaction"). As a result of the TexStar Rich Gas System Transcation, Holdings indirectly owns all of our Class B Convertible Units (the "Class B Convertible Units"). For additional details regarding the Holdings Transaction and the TexStar Rich Gas System Transaction, see Notes 1, 2, 6, 9, 10 and 13 to our condensed consolidated financial statements.

#### Holdings Drop-Down Acquisition

On May 7, 2015, we acquired gathering, treating, compression and transportation assets (the "2015 Holdings Acquisition") pursuant to a Purchase, Sale and Contribution Agreement among Holdings, TexStar Midstream Utility, LP, Frio LaSalle Pipeline, LP ("Frio"), us and certain of our subsidiaries. The acquired assets consist of the Valley Wells sour gas gathering and treating system (the "Valley Wells System"), compression assets that are part of the Valley Wells and Lancaster gathering and treating systems (the "Compression Assets") and two NGL pipelines. Total consideration for the assets was $77.6 million, consisting of $15.0 million in cash and 4.5 million new common units, valued as of the date of closing, issued to Holdings. Also, we assumed responsibility for funding the remaining capital expenditures for the completion of the NGL pipelines that were under construction at the time of the acquisition.

The Valley Wells System is located in the Eagle Ford Shale region, in LaSalle County, Texas. The system has sour gas treating capacity of approximately 100 MMcf/d and is supported by a 60 MMcf/d minimum volume commitment from Holdings for gathering and treating services, while Holdings has producer contracts with minimum volume commitments totaling 35 MMcf/d behind the system. The system is connected to our rich gas system for transport and processing. The assets acquired in the 2015 Holdings Acquisition includes over 50,000 horsepower of compression capability that serve both the Valley Wells and Lancaster gathering systems located primarily in Dimmit, Frio and LaSalle counties. The NGL pipelines, which were completed in June 2015, include a Y-grade pipeline that connects our Woodsboro processing facility to Holdings' Robstown fractionator ("Robstown") and a propane pipeline from our Bonnie View fractionator to Robstown.

The Valley Wells system, the Compression Assets and the Y-grade pipeline have long-term fixed-fee minimum volume or minimum utilization agreements that represent over 80% of the anticipated annualized EBITDA from the assets acquired in the 2015 Holdings Acquisition. The propane pipeline is anticipated to result in savings to us over the current cost of transportation for deliveries of propane from our Bonnie View fractionator. See Notes 2 and 9 to our condensed consolidated financial statements.

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Liquidity Consideration

As of September 30, 2015, we determined that we will not be in compliance with the consolidated total leverage ratio of our Financial Covenants (as defined in Note 6 to our condensed consolidated financial statements) absent an equity cure of approximately $5.3 million within approximately 15 days following the issuance of these financial statements. For additional details regarding this equity cure, see below and Note 1 to our condensed consolidated financial statements.

Amendment to Third A&R Revolving Credit Agreement

During the fourth quarter of 2014 and into the first quarter of 2015, as a result of the decline in commodity prices and associated decline in upstream drilling activity, we experienced a decline in the growth in volume of natural gas we gather and process for our customers. Our results in the first quarter of 2015 also were negatively impacted by the fire at our Gregory facility (See Note 5 to our condensed consolidated financial statements). These collective events impacted our operating results adversely and resulted in the need to amend the Third Amended and Restated Revolving Credit Agreement with Wells Fargo Bank, N.A., as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, JPMorgan Chase Bank, N.A., as Documentation Agent, and a syndicate of lenders (the "Third A&R Revolving Credit Agreement").

On May 7, 2015, we entered into a First Amendment to our Third A&R Revolving Credit Agreement among the Partnership, as the borrower, Wells Fargo, N.A., as the administrative agent, the lenders and other parties thereto (the "Credit Agreement Amendment"). The Credit Agreement Amendment amended the Third A&R Revolving Credit Agreement.

The Credit Agreement Amendment, among other things:

(a) (i) revised the maximum consolidated total leverage ratio set at 5.75 to 1.0 as of the last day of the fiscal quarter ending each of March 31, 2015, June 30, 2015 and September 30, 2015, (ii) 5.5 to 1.0 as of the last day of the fiscal quarter ending each of December 31, 2015, March 31, 2016 and June 30, 2016, (iii) 5.25 to 1.0 as of the last day of the fiscal quarter ending September 30, 2016, and (iv) 5.00 to 1.0 as of the last day of each fiscal quarter thereafter, in each case, without any step-ups in connection with acquisitions;

(b) increased the applicable margins used in connection with the loans and the commitment fee so that the applicable margin for Eurodollar Loans (as used in the Third A&R Revolving Credit Agreement) ranges from 2.00% to 4.50%, the applicable margin for base rate loans ranges from 1.00% to 3.50% and the applicable rate for commitment fees ranges from 0.375% to 0.500%;

(c) permits the Partnership to comply with certain Financial Covenants by making certain pro forma adjustments with respect to minimum revenues to be received from Frio;

(d) modified our ability to cure Financial Covenant Defaults (as defined in Note 6 to our condensed consolidated financial statements);

(e) imposed additional restrictions on our ability to declare and pay quarterly cash distributions with respect to our subordinated units;

(f) amended certain other provisions of the Third A&R Revolving Credit Agreement as more specifically set forth in the Credit Agreement Amendment; and

(g) allows us an unlimited number of quarterly equity cures related to our Financial Covenant Default through the fourth quarter of 2016, and no more than two in a twelve month period thereafter for the life of the agreement.

Additionally, we are unable to borrow on our Credit Facility (as defined below) until we have funded the required equity cure for the third quarter of 2015; however, we retain the ability to fund the required equity cure using a contractual non-cash credit amount of up to $13 million, $4.7 million of which was used to fund an equity cure in order to stay in compliance with the consolidated total leverage ratio for our Financial Covenants as of June 30, 2015.

Description of Business

We are a master limited partnership, headquartered in Dallas, Texas, that provides natural gas gathering, processing, treating, compression and transportation services and NGL fractionation and transportation services. We also source, purchase, transport and sell natural gas and NGLs. Our assets are located in South Texas, Mississippi and Alabama and include four gas processing plants, two fractionation facilities and our pipelines.

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Our Operations

Our integrated operations provide a full range of complementary services extending from wellhead to market, including gathering natural gas at the wellhead, treating natural gas to meet downstream pipeline and customer quality standards, processing natural gas to separate NGLs from natural gas, fractionating NGLs into the various components and selling or delivering pipeline quality natural gas, Y-grade and purity product NGLs to various industrial and energy markets as well as large pipeline systems. Through our network of pipelines, we connect supplies of natural gas to our customers, which include industrial, commercial and power generation customers and local distribution companies. All of our operations are managed as and presented in one reportable segment.

Our results are determined primarily by the volumes of natural gas we gather and process, the efficiency of our processing plants and NGL fractionation plants, the commercial terms of our contractual arrangements, natural gas and NGL prices and our operations and maintenance expense. We manage our business with the goal to maximize the gross operating margin we earn from contracts balanced against any risks we assume in our contracts. Our contracts vary in duration from one month to several years and the pricing under our contracts varies depending upon several factors, including our competitive position, our acceptance of risks associated with longer-term contracts and our desire to recoup over the term of the contract any capital expenditures that we are required to incur to provide service to our customers. We purchase, gather, process, treat, compress, transport and sell natural gas and purchase, fractionate, transport and sell NGLs. Contracts with a counterparty generally contain one or more of the following arrangements:

- Fixed-Fee. We receive a fixed-fee per unit of natural gas volume that we gather at the wellhead, process, treat, compress and/or transport for our customers, or we receive a fixed-fee per unit of NGL volume that we fractionate. Some of our arrangements also provide for a fixed-fee for guaranteed transportation capacity on our systems.
- Fixed-Spread. Under these arrangements, we purchase natural gas and NGLs from producers or suppliers at receipt points on our systems at an index price plus or minus a fixed price differential and sell these volumes of natural gas and NGLs at delivery points off our systems at the same index price, plus or minus a fixed price differential. By entering into such back-to-back purchases and sales, we are able to mitigate our risk associated with changes in the general commodity price levels of natural gas and NGLs. We remain subject to variations in our fixed-spreads to the extent we are unable to precisely match volumes purchased and sold in a given time period or are unable to secure the supply or to produce or market the necessary volume of products at our anticipated differentials to the index price.
- Commodity-Sensitive. In exchange for our processing services, we may remit to a customer a percentage of the proceeds from our sales, or a percentage of the physical volume, of residue natural gas and/or NGLs that result from our natural gas processing, or we may purchase NGLs from customers at set fixed NGL recoveries and retain the balance of the proceeds or physical commodity for our own account. These arrangements are generally combined with fixed-fee and fixed-spread arrangements for processing services and, therefore, represent only a portion of a processing contract's value. The revenues we receive from these arrangements directly correlate with fluctuating general commodity price levels of natural gas and NGLs and the volume of NGLs recovered relative to the fixed recovery obligations.

We assess gross operating margin opportunities across our integrated value stream so that processing margins may be supplemented by gathering and transportation fees and opportunities to sell residue gas and NGLs at fixed-spreads. Gross operating margin earned under fixed-fee and fixed-spread arrangements is directly related to the volume of natural gas that flows through our systems and is generally independent from general commodity price levels. A sustained decline in commodity prices could result in a decline in volumes entering our system and, thus, a decrease in gross operating margin for our fixed-fee and fixed-spread arrangements.

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The following table summarizes our gross operating margins from these arrangements (in thousands):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2015 | | 2014 | | 2015 | | 2014 | |
| | Gross Operating Margin | % | Gross Operating Margin | % | Gross Operating Margin | % | Gross Operating Margin | % |
| Fixed-fee | $36,523 | 79.1 % | $23,629 | 73.6 % | $107,006 | 80.1 % | $57,172 | 66.8 % |
| Fixed-spread | 4,012 | 8.7 % | 1,341 | 4.1 % | 10,687 | 8.0 % | 7,698 | 9.0 % |
| Sub-total | 40,535 | 87.8 % | 24,970 | 77.7 % | 117,693 | 88.1 % | 64,870 | 75.8 % |
| Commodity-sensitive | 5,633 | 12.2 % | 7,146 | 22.3 % | 15,924 | 11.9 % | 20,671 | 24.2 % |
| Total gross operating margin | $46,168 | 100.0 % | $32,116 | 100.0 % | $133,617 | 100.0 % | $85,541 | 100.0 % |

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a quarterly basis for consistency and trend analysis. These performance metrics include (a) volume, (b) gross operating margin, (c) operations and maintenance expense, (d) Adjusted EBITDA and (e) distributable cash flow.

Volume — We determine and analyze volumes by operating unit, but report overall volumes after elimination of intercompany deliveries. The volume of natural gas and NGLs on our systems depends on the level of production from natural gas wells connected to our systems and also from wells connected with other pipeline systems that are interconnected with our systems.

Gross Operating Margin — Gross operating margin of our contracts is one of the metrics we use to measure and evaluate our performance. Gross operating margin is not a measure calculated in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We define gross operating margin as the sum of revenues less the cost of natural gas and NGLs sold. For our fixed-fee contracts, we record the fee as revenue and there is no offsetting cost of natural gas and NGLs sold. For our fixed-spread and commodity-sensitive arrangements, we record as revenue all of our proceeds from the sale of the natural gas and NGLs and record as an expense the associated cost of natural gas and NGLs sold.

Operations and Maintenance Expense — Our management seeks to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating and maintaining our assets. Direct labor costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities and contract services comprise the most significant portion of our operations and maintenance expense. These expenses are relatively stable and largely independent of volumes delivered through our systems, but may fluctuate depending on the activities performed during a specific period.

Adjusted EBITDA and Distributable Cash Flow — We believe that Adjusted EBITDA and distributable cash flow are widely accepted financial indicators of our operational performance and our ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA and distributable cash flow are not measures calculated in accordance with GAAP.

We define Adjusted EBITDA as net income/loss, plus interest expense, income tax expense, depreciation and amortization expense, equity in losses of joint venture investments, certain non-cash charges (such as non-cash unit-based compensation, impairments, loss on extinguishment of debt and unrealized losses on derivative contracts), major litigation costs net of recoveries, transaction-related costs, revenue deferral adjustment, loss on sale of assets and selected charges that are unusual or non-recurring; less interest income, income tax benefit, unrealized gains on derivative contracts, equity in earnings of joint venture investments and selected gains that are unusual or non-recurring. Adjusted EBITDA should not be considered an alternative to net income, operating cash flow or any other measure of financial performance presented in accordance with GAAP.

Adjusted EBITDA is used as a supplemental measure by our management and by external users of these financial statements, such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to support our indebtedness and make future cash distributions;

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- operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on investment opportunities.

We define distributable cash flow as Adjusted EBITDA, plus interest income and income tax benefit, less cash paid for interest (net of capitalized costs), income tax expense and maintenance capital expenditures. We use distributable cash flow to analyze our performance and liquidity. Distributable cash flow does not reflect changes in working capital balances.

Distributable cash flow is used to assess:

- the ability of our assets to generate cash sufficient to support our indebtedness and make future cash distributions to our unitholders; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

Non-GAAP Financial Measures

Gross operating margin, Adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We believe that the presentation of these non-GAAP financial measures provides useful information to investors in assessing our financial condition, results of operations and cash flows from operations. Net income is the GAAP measure most directly comparable to each of gross operating margin and Adjusted EBITDA. The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Each of these non-GAAP financial measures has important limitations as an analytical tool because each excludes some but not all items that affect the most directly comparable GAAP financial measure. You should not consider any of gross operating margin, Adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross operating margin, Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Reconciliations of Non-GAAP Financial Measures

The following table presents a reconciliation of gross operating margin to net loss (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Reconciliation of gross operating margin to net loss: | | | | |
| Gross operating margin | $46,168 | $32,116 | $133,617 | $85,541 |
| Add (Deduct): | | | | |
| Income tax benefit (expense) | 190 | (69) | 113 | (133) |
| Equity in losses of joint venture investments | (3,567) | (3,308) | (10,722) | (3,308) |
| Interest expense | (8,688) | (4,596) | (24,087) | (9,340) |
| Loss on extinguishment of debt | — | (2,316) | — | (2,316) |
| Other expense | — | (86) | — | (86) |
| Loss (gain) on sale of assets, net | 33 | (334) | (146) | (292) |
| General and administrative | (6,803) | (15,085) | (23,612) | (27,881) |
| Impairment of assets | — | (1,556) | (193) | (1,556) |
| Depreciation and amortization | (17,853) | (12,701) | (52,456) | (30,207) |
| Operations and maintenance | (19,139) | (18,097) | (61,528) | (40,702) |

| | | | | |
|---|---|---|---|---|
| Net loss | $(9,659) | $(26,032) | $(39,014) | $(30,280) |

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The following table presents reconciliations of net cash provided by operating activities to net loss, Adjusted EBITDA and distributable cash flow (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Net cash provided by operating activities | $20,005 | $(2,796) | $24,508 | $20,905 |
| Add (deduct): | | — | | |
| Depreciation and amortization | (17,853) | (12,701) | (52,456) | (30,207) |
| Unit-based compensation | (1,038) | (9,226) | (3,513) | (10,837) |
| Amortization of deferred financing costs | (888) | (2,921) | (2,615) | (3,596) |
| Loss (gain) on sale of assets, net | 33 | (334) | (146) | (292) |
| Unrealized gain on financial instruments | (68) | (227) | (289) | (539) |
| Equity in losses of joint venture investments | (3,567) | (3,308) | (10,722) | (3,308) |
| Distribution from joint venture investment | (500) | — | (500) | — |
| Impairment of assets | — | (1,556) | (193) | (1,556) |
| Other, net | 67 | (27) | 69 | (81) |
| Changes in operating assets and liabilities: | | | | |
| Trade accounts receivable, including affiliates | 11,338 | 4,991 | (5,613) | 10,517 |
| Prepaid expenses and other current assets | 2,296 | 3,194 | 1,516 | 1,066 |
| Other non-current assets | (1) | 13 | (77) | 34 |
| Accounts payable and accrued expenses | (17,224) | 2,064 | 14,180 | (10,043) |
| Other liabilities, including affiliates | (2,259) | (3,198) | (3,163) | (2,343) |
| Net loss | $(9,659) | $(26,032) | $(39,014) | $(30,280) |
| Add (deduct): | | | | |
| Depreciation and amortization | $17,853 | $12,701 | $52,456 | $30,207 |
| Interest expense | 8,688 | 4,596 | 24,087 | 9,340 |
| Loss on extinguishment of debt | — | 2,316 | — | 2,316 |
| Income tax (benefit) expense | (190) | 69 | (113) | 133 |
| Unrealized loss (gain) on commodity swaps | (15) | 207 | (126) | 338 |
| Loss (gain) on sale of assets, net | (33) | 334 | 146 | 292 |
| Revenue deferral adjustment | 754 | 444 | 2,262 | 2,070 |
| Unit-based compensation | 1,038 | 609 | 3,513 | 2,220 |
| Major litigation costs, net of recoveries | 18 | 488 | 509 | 1,391 |
| Transaction-related costs | 613 | 10,506 | 1,785 | 10,813 |
| Equity in losses of joint venture investments | 3,567 | 3,308 | 10,722 | 3,308 |
| Severance expense | — | — | 734 | — |
| Valley Wells' operating expense cap adjustment | 505 | — | 1,023 | — |
| Impairment of assets | — | 1,556 | 193 | 1,556 |
| Other, net | 434 | — | 814 [(1)] | 62 |
| Adjusted EBITDA | $23,573 | $11,102 | $58,991 | $33,766 |
| Cash interest, net of capitalized costs | (7,750) | (3,962) | (21,317) | (7,833) |
| Income tax benefit (expense) | 190 | (69) | 112 | (133) |
| Maintenance capital expenditures | (3,351) | (1,309) | (8,968) | (4,047) |
| Distributable cash flow | $12,662 | $5,762 | $28,818 | $21,753 |

(1) This amount includes an immaterial amount related to the effects of presenting our financial results on an as-if pooled basis (in connection with the 2015 Holdings Acquisition discussed in Note 2 to our condensed consolidated financial statements).

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Results of Operations

The following table summarizes our results of operations (in thousands, except operating data):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Revenues: | | | | |
| Revenues | $147,114 | $206,388 | $471,735 | $615,042 |
| Revenues - affiliates | 32,455 | 6,290 | 60,993 | 6,290 |
| Total revenues | 179,569 | 212,678 | 532,728 | 621,332 |
| Expenses: | | | | |
| Cost of natural gas and liquids sold | 133,401 | 180,562 | 399,111 | 535,791 |
| Operations and maintenance | 19,139 | 18,097 | 61,528 | 40,702 |
| Depreciation and amortization | 17,853 | 12,701 | 52,456 | 30,207 |
| General and administrative | 6,803 | 15,085 | 23,612 | 27,881 |
| Impairment of assets | — | 1,556 | 193 | 1,556 |
| Loss (gain) on sale of assets, net | (33) | 334 | 146 | 292 |
| Total expenses | 177,163 | 228,335 | 537,046 | 636,429 |
| Income (loss) from operations | 2,406 | (15,657) | (4,318) | (15,097) |
| Other expense: | | | | |
| Equity in losses of joint venture investments | (3,567) | (3,308) | (10,722) | (3,308) |
| Interest expense | (8,688) | (4,596) | (24,087) | (9,340) |
| Loss on extinguishment of debt | — | (2,316) | — | (2,316) |
| Other expense | — | (86) | — | (86) |
| Total other expense | (12,255) | (10,306) | (34,809) | (15,050) |
| Loss before income tax benefit (expense) | (9,849) | (25,963) | (39,127) | (30,147) |
| Income tax benefit (expense) | 190 | (69) | 113 | (133) |
| Net loss | $(9,659) | $(26,032) | $(39,014) | $(30,280) |
| Other financial data: | | | | |
| Adjusted EBITDA | $23,573 | $11,102 | $58,991 | $33,766 |
| Gross operating margin | $46,168 | $32,116 | $133,617 | $85,541 |
| Maintenance capital expenditures | $3,351 | $1,309 | $8,968 | $4,047 |
| Growth capital expenditures | $25,636 | $28,693 | $84,978 | $99,323 |
| Operating data: | | | | |
| Average throughput volumes of natural gas (MMcf/d) (1)(2) | | | | |
| South Texas | 724 | 591 | 742 | 541 |
| Mississippi and Alabama | 216 | 185 | 234 | 195 |
| Total average throughput volumes of natural gas | 940 | 776 | 976 | 736 |
| Average volume of processed gas (MMcf/d) (2) | 441 | 317 | 432 | 253 |
| Average volume of NGLs produced (Bbls/d) | 43,541 | 25,755 | 42,031 | 18,353 |
| Average volume of NGLs fractionated (Bbls/d) | 8,229 | 20,082 | 13,577 | 16,967 |
| Realized prices on natural gas volumes ($/Mcf) | $3.61 | $4.71 | $3.07 | $5.29 |
| Realized prices on NGL volumes ($/gal) | 0.34 | 0.81 | 0.38 | 0.87 |

(1) Average throughput volumes of natural gas per day include sales, transportation, fuel and shrink volumes.
(2) Prior to this quarter, we presented average throughput volumes of natural gas and average volume of processed gas in MMBtu instead of MMcf.

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Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

Volume and overview. Our average throughput volume of natural gas per day increased by 164 MMcf/d, or 21%, to 940 MMcf/d during the three months ended September 30, 2015, compared to 776 MMcf/d during the three months ended September 30, 2014, due primarily to increased gas volumes in South Texas from the TexStar Rich Gas System and Onyx (as defined in Note 2 to our condensed consolidated financial statements) acquisitions as well as increases in volume from new and existing customers in the Eagle Ford Shale region. Beginning in the second half of 2014 and continuing through the issuance of these financial statements, commodity prices have experienced increased volatility. In particular, natural gas, crude oil and NGL prices have decreased significantly. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration of the commodities we sell or there is a continuing material reduction in drilling for oil or natural gas in the geographic areas in which we operate, including the Eagle Ford Shale region.

Processed gas volumes increased 124 MMcf/d, or 39%, to 441 MMcf/d during the three months ended September 30, 2015, compared to 317 MMcf/d during the three months ended September 30, 2014. This increase was due primarily to increased volumes from the TexStar Rich Gas System Transaction and increases in volumes from new and existing customers in the Eagle Ford Shale region.

NGLs produced at our processing plants for the three months ended September 30, 2015 averaged 43,541 Bbls/d, an increase of 69%, or 17,786 Bbls/d, compared to 25,755 Bbls/d for the three months ended September 30, 2014. The increase in NGLs produced is due primarily to increased throughput volumes and additional rich gas volumes through our processing plants as a result of the TexStar Rich Gas System Transaction. With the completion of the fractionator at Robstown and the associated incremental fractionation capacity, we view total NGLs produced as an important performance metric that we use to evaluate our business. Prior to the completion of Robstown, a portion of NGLs produced at our processing plants were directed to third-party fractionators. Due to the interconnected nature of our system and associated intercompany agreements, we receive an economic benefit regardless of whether NGLs are fractionated at our or Holdings' facilities.

NGLs fractionated for the three months ended September 30, 2015 averaged 8,229 Bbls/d, a decrease of 11,853 Bbls/d, or 59%, compared to 20,082 Bbls/d for the three months ended September 30, 2014. This decrease was due primarily to temporary operational issues experienced at our Bonnie View facility that resulted in fractionation capacity being limited to approximately 50% during the three months ended September 30, 2015 compared to the three months ended September 30, 2014. However, as noted above, the economic impact of this decrease was partially offset by directing NGLs produced to Holdings' facilities.

Gross operating margin for the three months ended September 30, 2015 was $46.2 million, compared to $32.1 million for the three months ended September 30, 2014. This increase of $14.1 million, or 44%, was due primarily to increased processed gas volumes and margins on our system, as well as increased transportation, gathering and processing fees.

Adjusted EBITDA increased by $12.5 million, or 113%, to $23.6 million for the three months ended September 30, 2015, compared to $11.1 million for the three months ended September 30, 2014, due primarily to higher processed gas volumes and margins from processing activities. We had a net loss of $9.7 million for the three months ended September 30, 2015 compared to a net loss of $26.0 million for the three months ended September 30, 2014. Net loss decreased by $16.3 million primarily due to increased gross operating margin and decreased general and administrative expenses, partially offset by additional depreciation and amortization expense from acquisitions and increased interest expense from higher average borrowings.

Revenues. Our total revenues for the three months ended September 30, 2015 decreased $33.1 million, or 16%, to $179.6 million compared to $212.7 million for the three months ended September 30, 2014. This was due primarily to revenue from sales of natural gas decreasing by $19.8 million due to a decrease in realized prices in natural gas, and revenue from sales of NGLs and condensate decreasing by $26.3 million due to a decrease in realized prices in NGLs for the three months ended September 30, 2015 compared to the three months ended September 30, 2014. This decrease was partially offset by increased revenue of $20.5 million resulting from the addition of the TexStar Rich Gas System Transaction, the Onyx acquisition and Texoz acquisition (each as defined in Note 2 to our condensed consolidated financial statements).

Cost of natural gas and NGLs sold. Our cost of natural gas and NGLs sold for the three months ended September 30, 2015 was $133.4 million, compared to $180.6 million for the three months ended September 30, 2014. This decrease of $47.2 million, or 26%, was due primarily to lower natural gas and NGL prices compared to the same period in 2014.

Operations and maintenance expenses. Operations and maintenance expenses for the three months ended September 30, 2015 were $19.1 million, compared to $18.1 million for the three months ended September 30, 2014. This increase of $1.0 million, or 6%, was due primarily to higher utilities of $1.1 million, primarily related to assets acquired in the TexStar Rich Gas

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System Transaction in August 2014, during the three months ended September 30, 2015 compared to the three months ended September 30, 2014.

General and administrative expenses. General and administrative expenses for the three months ended September 30, 2015 were $6.8 million, compared to $15.1 million for the three months ended September 30, 2014. This decrease of $8.3 million, or 55%, was due primarily to $6.6 million of one-time compensation expense in the third quarter of 2014 from the accelerated vesting of the LTIP awards, as a result of the change in control in August 2014, and decreased professional fees of $1.7 million, mostly related to the TexStar Rich Gas System Transaction, for the three months ended September 30, 2015 compared to the three months ended September 30, 2014.

Depreciation and amortization expense. Depreciation and amortization expense for the three months ended September 30, 2015 was $17.9 million, compared to $12.7 million for the three months ended September 30, 2014. The increase of $5.2 million, or 41%, was due primarily to depreciation of the TexStar Rich Gas System assets acquired in the third quarter of 2014, the 2015 Holdings Acquisition and other capital projects placed in service during 2014.

Equity in losses of joint venture investments. Our share of losses incurred by the joint venture investments acquired as part of the TexStar Rich Gas System assets was $3.6 million for the three months ended September 30, 2015 compared to $3.3 million for the three months ended September 30, 2014, for an increase of $0.3 million, or 9%. We pay our proportionate share of the joint ventures' operating costs, excluding depreciation and amortization, through lease capacity payments. As a result, our share of the joint ventures' losses is primarily related to the joint ventures' depreciation and amortization.

Interest expense. For the three months ended September 30, 2015, interest expense was $8.7 million, compared to $4.6 million for the three months ended September 30, 2014. This increase of $4.1 million was due to higher average borrowings related primarily to the debt incurred as part of the TexStar Rich Gas System Transaction and higher interest rates on borrowings.

Loss on extinguishment of debt. In the third quarter of 2014, we incurred a loss on the extinguishment of debt of $2.3 million in connection with the write-off of deferred financing costs related to exiting the Previous Credit Facility and entering into the Senior Credit Facilities in August 2014.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

Volume and overview. Our average throughput volume of natural gas per day increased by 240 MMcf/d, or 33%, to 976 MMcf/d during the nine months ended September 30, 2015, compared to 736 MMcf/d during the nine months ended September 30, 2014, due primarily to increased gas volumes in South Texas from the TexStar Rich Gas System and Onyx (as defined in Note 2 to our condensed consolidated financial statements) acquisitions as well as increases in volume from new and existing customers in the Eagle Ford Shale region.

Processed gas volumes increased 179 MMcf/d, or 71%, to 432 MMcf/d during the nine months ended September 30, 2015, compared to 253 MMcf/d during the nine months ended September 30, 2014. This increase was due primarily to increased volumes from the TexStar Rich Gas System Transaction and increases in volumes from new and existing customers in the Eagle Ford Shale region.

NGLs produced at our processing plants for the three months ended September 30, 2015 averaged 42,031 Bbls/d, an increase of 129%, or 23,678 Bbls/d, compared to 18,353 Bbls/d for the three months ended September 30, 2014. The increase in NGLs produced is due primarily to increased throughput volumes and additional rich gas volumes through our processing plants as a result of the TexStar Rich Gas System Transaction in August 2014.

NGLs fractionated for the nine months ended September 30, 2015 averaged 13,577 Bbls/d, a decrease of 3,390 Bbls/d, or 20%, compared to 16,967 Bbls/d for the nine months ended September 30, 2014. This decrease was due primarily to temporary operational issues experienced at our Bonnie View facility that resulted in fractionation capacity being limited to approximately 50% in the third quarter of 2015, partially offset by the impact of additional volumes of rich gas on our system during the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014.

Gross operating margin for the nine months ended September 30, 2015 was $133.6 million, compared to $85.5 million for the nine months ended September 30, 2014. This increase of $48.1 million, or 56%, was due primarily to increased processed gas volumes and margins on our system, as well as increased transportation, gathering and processing fees.

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Adjusted EBITDA increased by $25.2 million, or 75%, to $59.0 million for the nine months ended September 30, 2015, compared to $33.8 million for the nine months ended September 30, 2014, due to higher processed gas volumes and margins from processing activities, partially offset by higher operating expenses. We had a net loss of $39.0 million for the nine months ended September 30, 2015 compared to a net loss of $30.3 million for the nine months ended September 30, 2014. Net loss increased by $8.7 million due primarily to increased operations and maintenance expenses, additional depreciation and amortization expense from acquisitions and increased interest expense from higher average borrowings, partially offset by increased gross operating margin.

Revenues. Our total revenues for the nine months ended September 30, 2015 decreased $88.6 million, or 14%, to $532.7 million compared to $621.3 million for the nine months ended September 30, 2014. This decrease was due primarily to revenue from sales of natural gas decreasing by $83.3 million due to a decrease in realized prices in natural gas, and revenue from sales of NGLs and condensate decreasing by $55.9 million due to a decrease in realized prices in NGLs for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014. This decrease was partially offset by increased revenue of $75.8 million resulting from the addition of the TexStar Rich Gas System Transaction, the Onyx acquisition and Texoz acquisition.

Cost of natural gas and NGLs sold. Our cost of natural gas and NGLs sold for the nine months ended September 30, 2015 was $399.1 million, compared to $535.8 million for the nine months ended September 30, 2014. This decrease of $136.7 million, or 26%, was due primarily to lower natural gas and NGL prices compared to the same period in 2014.

Operations and maintenance expenses. Operations and maintenance expenses for the nine months ended September 30, 2015 were $61.5 million, compared to $40.7 million for the nine months ended September 30, 2014. This increase of $20.8 million, or 51%, was due primarily to higher fees of $7.6 million, higher operating costs of $3.3 million, increased utilities costs of $3.0 million, and higher material costs of $2.5 million all due primarily to the acquisition of additional assets during the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014.

General and administrative expenses. General and administrative expenses for the nine months ended September 30, 2015 were $23.6 million, compared to $27.9 million for the nine months ended September 30, 2014. This decrease of $4.3 million, or 15%, was due primarily to $6.6 million of one-time compensation expense in the third quarter of 2014 from the accelerated vesting of the LTIP awards, as a result of the change in control in August 2014, partially offset by increased labor and benefits costs of $2.2 million from employee additions for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014.

Depreciation and amortization expense. Depreciation and amortization expense for the nine months ended September 30, 2015 was $52.5 million, compared to $30.2 million for the nine months ended September 30, 2014. The increase of $22.3 million, or 74%, was due primarily to depreciation of the TexStar Rich Gas System assets acquired in the third quarter of 2014, the 2015 Holdings Acquisition and other capital projects placed in service during 2014.

Equity in losses of joint venture investments. Our share of losses incurred by the joint venture investments acquired as part of the TexStar Rich Gas System assets was $10.7 million for the nine months ended September 30, 2015 compared to $3.3 million for the nine months ended September 30, 2014. This increase of $7.4 million was due to the fact that the joint venture investments were acquired on August 4, 2014, and thus the 2014 amount only includes two months of activity.

Interest expense. For the nine months ended September 30, 2015, interest expense was $24.1 million, compared to $9.3 million for the nine months ended September 30, 2014. This increase of $14.8 million was due to higher average borrowings related primarily to the debt incurred as part of the TexStar Rich Gas System Transaction and higher interest rates on borrowings.

Loss on extinguishment of debt. In the third quarter of 2014, we incurred a loss on the extinguishment of debt of $2.3 million in connection with the write-off of deferred financing costs related to exiting the Previous Credit Facility and entering into the Senior Credit Facilities in August 2014.

## Liquidity and Capital Resources

### Sources of Liquidity

Our primary sources of liquidity are cash generated from operations, cash raised through issuances of additional equity and debt securities and borrowings under our Senior Credit Facilities (as defined in Note 6 to our condensed consolidated financial statements). Our primary cash requirements consist of operating and maintenance and general and administrative expenses, growth and maintenance capital expenditures to sustain existing operations or generate additional revenues, interest payments on outstanding debt, purchases and construction of new assets, business acquisitions and distributions to unitholders.

We expect to fund short term cash requirements, such as operating and maintenance and general and administrative expenses and maintenance capital expenditures, primarily through operating cash flows. We expect to fund long-term cash requirements, such as for expansion projects and acquisitions, through several sources, including operating cash flows, borrowings under our Senior Credit Facilities and issuances of additional debt and equity securities, as appropriate and subject to market conditions. See Note 6 to our condensed consolidated financial statements.

Beginning in the second half of 2014 and continuing through the issuance of these financial statements, commodity prices have experienced increased volatility. In particular, natural gas, crude oil and NGL prices have decreased significantly. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration of the commodities we sell or there is a continuing material reduction in drilling for oil or natural gas in the geographic areas in which we operate, including the Eagle Ford Shale region. See Note 1 to our condensed consolidated financial statements.

The majority of our revenue is derived from fixed-fee contracts, which have limited direct exposure to commodity price levels since we are paid based on the volumes of natural gas that we gather, process, treat, compress and transport and the volumes of NGLs we fractionate and transport, rather than being paid based on the value of the underlying natural gas or NGLs. In addition, a percentage of our contract portfolio contains minimum volume commitment arrangements. The majority of our volumes are dependent upon the level of producer drilling activity. After considering these uncertainties, we anticipate potential future shortfalls in the amount of consolidated EBITDA (as defined in our Third A&R Revolving Credit Agreement, as amended in May 2015) necessary to remain in compliance with the consolidated total leverage ratio of our Financial Covenants in our Credit Facility. As discussed in further detail in Note 6 to our condensed consolidated financial statements, we have the right to cure such a Financial Covenant Default by either our Sponsors or Holdings purchasing equity interests in or making capital contributions (an equity cure) resulting in, among other things, proceeds that, if added to consolidated EBITDA, would result in us satisfying the Financial Covenants. Once such an equity cure is made, it is included in our consolidated EBITDA calculation in any rolling twelve month period that includes the quarter that was cured. Should there be an event of default under the Credit Facility, and such default is not cured, we would also experience a cross default under our Term Loan Agreement (defined in Note 6 to our condensed consolidated financial statements) and all of our debt would become due and payable to our lenders.

As of September 30, 2015, we determined that we will not be in compliance with the consolidated total leverage ratio of our Financial Covenants absent an equity cure of approximately \$5.3 million within approximately 15 days following the issuance of these financial statements. We believe that we will have the ability to fund this equity cure with the remaining \$8.3 million non-cash equity cure credit amount from our Credit Agreement Amendment. We used \$4.7 million of the contractual \$13.0 million non-cash equity cure credit amount from our Credit Agreement Amendment to fund an equity cure in order to stay in compliance with the consolidated total leverage ratio of our Financial Covenants as of June 30, 2015. See Note 1 to our condensed consolidated financial statements. We anticipate funding additional equity cures needed to maintain compliance with our Financial Covenants through the end of 2016 with the remainder of the non-cash equity cure credit amount, the \$50 million Sponsor equity commitment described below, or a combination of the two.

In response to our need for additional liquidity and the need for the Partnership to maintain compliance with our Financial Covenants, our Sponsors have committed to provide the necessary funding to support us for at least a reasonable period of time in an amount up to $50 million, which was increased from $25 million in August 2015, to ensure we have sufficient liquidity to comply with applicable Financial Covenants and to fund normal operating and growth capital requirements. Therefore, our financial statements have been presented as if we will continue as a going concern. See Note 6 to our condensed consolidated financial statements.

As of November 3, 2015, we had $595.5 million in outstanding borrowings under our Senior Credit Facilities. Under our five-year revolving credit facility, pursuant to our Third A&R Revolving Credit Agreement, we have the ability to borrow up to $200 million (the "Credit Facility") less any letters of credit amounts outstanding, which as of November 3, 2015 provided us access to $30.9 million. However, we are unable to borrow on our Credit Facility until we have funded the required equity cure for the third quarter of 2015 with the available funding options described above.

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On May 7, 2015, we entered into a first amendment to our Third A&R Revolving Credit Agreement that provides for more favorable financial covenants through the third quarter of 2016 and established an equity cure that is available through the end of 2016. See Note 6 to our condensed consolidated financial statements.

Capital expenditures. Our business is capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of and will continue to include:

- growth capital expenditures, which are capital expenditures to expand or increase the efficiency of the existing operating capacity of our assets. Growth capital expenditures include expenditures that facilitate an increase in volumes within our operations, but exclude expenditures for acquisitions; and
- maintenance capital expenditures, which are capital expenditures that are not considered growth capital expenditures.

The following table summarizes our capital expenditures (in thousands):

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Maintenance capital | $3,351 | $1,309 | $8,968 | $4,047 |
| Growth capital | 25,636 | 28,693 | 84,978 | 99,323 |
| Capital expenditures | $28,987 | $30,002 | $93,946 | $103,370 |

Our growth capital expenditures during the nine months ended September 30, 2015 relate primarily to various expansion and improvement projects primarily in our South Texas assets. The growth capital expenditures during the nine months ended September 30, 2014 related primarily to construction of an addition to our pipeline system extending into Webb County, Texas.

Outlook. Cash flow is affected by a number of factors, some of which we cannot control. These factors include prices and demand for our services, operational risks, volatility in commodity prices or interest rates, industry and economic conditions, conditions in the financial markets and other factors.

Our ability to benefit from growth projects to accommodate drilling activity and the associated need for infrastructure assets and services is subject to operational risks and uncertainties such as the uncertainty inherent in some of the assumptions underlying design specifications for new, modified or expanded facilities. These risks also impact third party service providers and their facilities. Delays or under-performance of our facilities or third party facilities may adversely affect our ability to generate cash from operations and comply with our obligations, including the covenants under our debt instruments. In other cases, actual production delivered may fall below volume estimates that we relied upon in deciding to pursue an acquisition or other growth project. Future cash flow and our ability to comply with our debt covenants would likewise be affected adversely if we experienced declining volumes over a sustained period and/or unfavorable commodity prices.

We believe that cash from operations, cash on hand, commitments from our Sponsors discussed above, and our unused borrowings under our Senior Credit Facilities will provide liquidity to meet future short term capital requirements for a reasonable period of time. The sufficiency of these liquidity sources to fund necessary and committed capital needs will be dependent upon our ability to meet our covenant requirements of our Senior Credit Facilities. We believe we have and will continue to have sufficient liquidity to operate our business. See Notes 1 and 6 to our condensed consolidated financial statements.

Growth projects and acquisitions are key elements of our business strategy. We intend to finance our growth capital primarily through the issuance of debt and equity. The timing, size or success of any acquisition or expansion effort and the associated potential capital commitments are unpredictable. To consummate acquisitions or capital projects, we may require access to additional capital. Our access to capital over the longer term will depend on our future operating performance, financial condition and credit rating and, more broadly, on the availability of equity and debt financing, which will be affected by prevailing conditions in our industry, the economy and the financial markets and other financial and business factors, many of which are beyond our control.

Cash Flows

The following table provides a summary of our cash flows by category (in thousands):

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2015 | 2014 |
| Net cash provided by operating activities | $24,508 | $20,905 |
| Net cash used in investing activities | (109,209) | (221,104) |
| Net cash provided by financing activities | 84,703 | 198,672 |

Operating cash flows — Net cash provided by operating activities was $24.5 million for the nine months ended September 30, 2015, compared to $20.9 million for the nine months ended September 30, 2014. The increase in cash from operating activities primarily was the result of increased net earnings after adjusting for non-cash items during the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014.

Investing cash flows — Net cash used in investing activities for the nine months ended September 30, 2015 was $109.2 million, compared to $221.1 million for the nine months ended September 30, 2014. The decrease of $111.9 million primarily relates to the TexStar Rich Gas System Transaction in August 2014, the Onyx acquisition in March 2014 and decreased capital expenditures, partially offset by the cash consideration paid in the 2015 Holdings Acquisition.

Financing cash flows — Net cash provided by financing activities for the nine months ended September 30, 2015 was $84.7 million, compared to $198.7 million for the nine months ended September 30, 2014. The decrease was due to proceeds received from our $144.7 million equity offering, net of expenses, in the first quarter of 2014 and reduced net borrowings of $89.0 million from our debt instruments, partially offset by $100 million of debt assumed and immediately repaid by us in connection with the TexStar Rich Gas System Transaction.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Recent Accounting Pronouncements

For information on new accounting pronouncements, see Note 1 to our condensed consolidated financial statements.

Critical Accounting Policies and Estimates

Our critical accounting policies are described in our 2014 Annual Report on Form 10-K. The preparation of financial statements in conformity with GAAP requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. There have been no significant changes to our critical accounting policies as described in our 2014 Annual Report on Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

There have been no significant changes to our quantitative and qualitative disclosures about market risk as described in our 2014 Annual Report on Form 10-K.

Item 4. Controls and Procedures.

Disclosure controls and procedures. The Chief Executive Officer and Chief Financial Officer of our General Partner, who have responsibility for our management, have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)), as of the end of the period covered by this report (the “Evaluation Date”). Based on such evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner have concluded that, as of the Evaluation Date, our disclosure controls and procedures are effective.

Internal control over financial reporting. There were no changes in our system of internal control over financial reporting (as defined in Rule 13a—15(f) or Rule 15d—15(f) of the Exchange Act) during the third quarter of 2015 that have materially affected or are reasonably likely to materially affect, our internal control over financial reporting.

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## PART II — OTHER INFORMATION

### Item 1. Legal Proceedings.

A description of our material legal proceedings is included in Note 7 to our condensed consolidated financial statements, and is incorporated herein by reference.

### Item 1A. Risk Factors.

The risk factors contained in our 2014 Annual Report on Form 10-K under Part I, Item 1A "Risk Factors," as updated by the Current Report on Form 8-K dated August 20, 2015, are incorporated herein by reference. There have been no material changes in our risk factors since that report.

These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, results of operations and financial condition and our ability to make distributions.

### Item 6. Exhibits.

The information set forth in the Index to Exhibits accompanying this report is incorporated into this Item 6 by reference.

## 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.

SOUTHCROSS ENERGY PARTNERS, L.P.

By: Southcross Energy Partners GP, LLC, its general partner

Date: November 6, 2015

By: /s/ Bret M. Allan
Bret M. Allan
Senior Vice President and Chief Financial Officer
Principal Financial Officer

Date: November 6, 2015

By: /s/ G. Tracy Owens
G. Tracy Owens
Vice President and Chief Accounting Officer
Principal Accounting Officer

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INDEX TO EXHIBITS

| Exhibit Number | Description |
|---|---|
| 3.1 | Certificate of Limited Partnership of Southcross Energy Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (Commission File No. 333-180841)). |
| 3.2 | Third Amended and Restated Agreement of Limited Partnership of Southcross Energy Partners, L.P., dated as of August 4, 2014 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 4, 2014). |
| 3.3 | Certificate of Formation of Southcross Energy Partners GP, LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (Commission File No. 333-180841)). |
| 3.4 | Second Amended and Restated Limited Liability Company Agreement of Southcross Energy Partners GP, LLC, dated as of August 4, 2014 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K dated August 4, 2014). |
| 4.1 | Registration Rights Agreement, dated as of April 12, 2013, by and between Southcross Energy Partners, L.P. and Southcross Energy LLC (incorporated by reference to Exhibit 4.1 to our Annual Report on Form 10-K for the fiscal year ending December 31, 2012). |
| 10.1 | General Release Agreement, executed July 3, 2015 and effective June 26, 2015, by and between Southcross Energy Partners GP, LLC and J. Michael Anderson (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated July 3, 2015). |
| 31.1* | Certification of Chief Executive Officer required by Rule 13a-14(a)/15d-14(a). |
| 31.2* | Certification of Chief Financial Officer required by Rule 13a-14(a)/15d-14(a). |
| 32.1** | Certifications of Chief Executive Officer and Chief Financial Officer required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350). |
| 101.INS*† | XBRL Instance Document. |
| 101.SCH*† | XBRL Taxonomy Extension Schema. |
| 101.CAL*† | XBRL Taxonomy Extension Calculation Linkbase. |
| 101.DEF*† | XBRL Taxonomy Extension Definition Linkbase. |
| 101.LAB*† | XBRL Taxonomy Extension Label Linkbase. |
| 101.PRE*† | XBRL Extension Presentation Linkbase. |

* Filed herewith.
** Furnished herewith.
† The financial information contained in the XBRL (eXtensible Business Reporting Language)-related documents is unaudited.