Southcross Energy Partners, L.P.
Form 10-K
March 09, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
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 (State or other jurisdiction of incorporation or organization)	45-5045230 (I.R.S. Employer Identification No.)
1717 Main Street, Suite 5200 Dallas, TX (Address of principal executive offices)	75201 (Zip Code)

(214) 979-3700
www.southcrossenergy.com
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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 o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller Reporting company x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x
The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2016 was approximately 44,038,384 based on the closing sale price and the number of outstanding common units held by non-affiliates on such date as reported on the New York Stock Exchange.

As of March 1, 2017, the registrant has 48,516,567 common units, 12,213,713 subordinated units and 17,405,250 Class B Convertible Units outstanding. The registrant's common units trade on the New York Stock Exchange under the symbol "SXE".
DOCUMENTS INCORPORATED BY REFERENCE
None

Table of contents

As generally used in the energy industry and in this Form 10-K, 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
Lean gas: Natural gas that is low in NGL content
MMBtu: One million British thermal units
Mcf: One thousand cubic feet
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: The 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 or 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, butane and natural gasoline

Table of contents

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2016

Table of contents

FORWARD-LOOKING INFORMATION

Investors are cautioned that certain statements contained in this Annual Report on Form 10-K ("Form 10-K") 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 be," "will continue," "will likely result," and similar expressions, or future conditional verbs such as "may," "will," "should," "would" 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 herein.

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 Form 10-K 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 continued reduction in exploration, development and production of crude oil and 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 nonperformance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- the financial condition and creditworthiness of our 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, treating, compression and transportation 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 as a result of the depressed energy price environment;
- our ability to generate sufficient operating cash flow to resume funding 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;
- the impact on our financial condition and operations resulting from the financial condition and operations of our controlling unitholder, Southcross Holdings LP and its ability to pay amounts to us;
- 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.

Table of contents

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

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 publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law.

Table of contents

Item 1. Business

The following discussion of our business provides information regarding our principal gathering, transportation, processing, NGL fractionation and other assets. For a discussion of our results of operations, please read Part II, Item 7 of this report.

General 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." 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 two gas processing plants, one fractionation facility and gathering and transportation pipelines.

Southcross Holdings LP, a Delaware limited partnership ("Holdings"), indirectly owns 100% of Southcross Energy Partners GP, LLC, a Delaware limited liability company, our general partner ("General Partner") (and therefore controls us), all of our subordinated and Class B convertible units (the "Class B Convertible Units") and 54.6% of our common units. Our General Partner owns an approximate 2.0% interest in us and all of our incentive distribution rights. Following the emergence of Holdings from its Chapter 11 reorganization proceeding on April 13, 2016 (as discussed below), EIG Global Energy Partners, LLC ("EIG") and Tailwater Capital LLC ("Tailwater") (collectively, the "Sponsors") each indirectly own approximately one-third of Holdings, and a group of consolidated lenders under Holdings' term loan (the "Lenders") own the remaining one-third of Holdings.

Recent Developments

Amendments to the Third Amended and Restated Revolving Credit Agreement

On July 25, 2016, we determined Holdings' cash contribution to us for the first quarter 2016 equity cure had not been transferred to us timely, as required under the Third Amended and Restated Revolving Credit Agreement with Wells Fargo, N.A., UBS Securities LLC, Barclays Bank PLC and a syndicate of lenders (the "Third A&R Revolving Credit Agreement"), as amended in May 2015, due to an administrative oversight, which resulted in a default. On July 26, 2016, Holdings fully funded the first quarter 2016 equity cure. On August 4, 2016, we entered into a limited waiver and second amendment to the Third A&R Revolving Credit Agreement whereby the lenders waived any default or right to exercise any remedy as a result of this technical event of default to fund timely the first quarter 2016 equity cure.

On November 8, 2016, we entered into a limited waiver and third amendment to the Third A&R Revolving Credit Agreement (the "Third Amendment"), which stipulated, among other things, that (i) the equity cure funding deadline for the quarter ended September 30, 2016 ("Q3 2016 Equity Cure") was extended from November 23, 2016 to December 16, 2016, and (ii) limited the total revolving credit exposure. On December 9, 2016, we entered into the waiver and fourth amendment to the Third A&R Revolving Credit Agreement (the "Fourth Amendment"), which stipulated, among other things, that (i) the deadline for funding the Q3 2016 Equity Cure was further extended from December 16, 2016 to January 12, 2017, and (ii) the Third A&R Revolving Credit Agreement was amended to require that any account into which we deposit funds, securities or commodities be subject to a lien and control agreement for the benefit of the secured parties under the Third A&R Revolving Credit Agreement.

On December 29, 2016, we entered into the waiver and fifth amendment to the Third A&R Revolving Credit Agreement (the "Fifth Amendment"), pursuant to which we received a full waiver for all defaults or events of default arising out of our failure to comply with the financial covenant to maintain a Consolidated Total Leverage Ratio less than 5.00 to 1.00 for the quarter ended September 30, 2016.

Additionally, pursuant to the Fifth Amendment, (i) total aggregate commitments under the Third A&R Revolving Credit Agreement were reduced from $200 million to $145 million and the sublimit for letters of credit also was reduced from $75 million to $50 million (total aggregate commitments will be further reduced periodically through December 31, 2018); (ii) the Consolidated Total Leverage Ratio and Consolidated Senior Secured Leverage Ratio (each of which is defined in the Fifth Amendment) financial covenants were suspended until the quarter ended March

31, 2019; (iii) the Consolidated Interest Coverage Ratio (as defined in the Fifth Amendment) financial covenant requirement was reduced from 2.50 to 1.00 to 1.50 to 1.00 for all periods ending on or prior to December 31, 2018 (the “Ratio Compliance Date”). Prior to the Ratio Compliance

Table of contents

Date, we are required to maintain minimum levels of Consolidated EBITDA on a quarterly basis and are subject to certain covenants and restrictions related to liquidity and capital expenditures. See Note 7 to our consolidated financial statements.

In connection with the execution of the Fifth Amendment, on December 29, 2016, the Partnership entered into (i) an Investment Agreement (the “Investment Agreement”) with Holdings and Wells Fargo Bank, N.A., (ii) a Backstop Commitment Letter (the “Backstop Agreement”) with Holdings, Wells Fargo Bank, N.A. and the Sponsors and (iii) a First Amendment to Equity Cure Contribution Agreement (the “Equity Cure Contribution Amendment”) with Holdings. Pursuant to the Equity Cure Contribution Amendment, on December 29, 2016, Holdings contributed $17.0 million to us in exchange for 11,486,486 common units. The proceeds of the $17.0 million contribution were used to pay down the outstanding balance under the Third A&R Revolving Credit Agreement and for general corporate purposes. In addition, pursuant to entering into the Investment Agreement, the previous Equity Cure Contribution Agreement with Holdings terminated and Holdings agreed to contribute $15.0 million to us (the “Committed Amount”) upon the earlier to occur of December 31, 2017 or notification from the Partnership of an event of default under the Third A&R Revolving Credit Agreement. In exchange for the amounts contributed pursuant to the Investment Agreement upon a Partial Investment Trigger or the Full Investment Trigger (as defined in the Investment Agreement), we will issue to Holdings, at Holdings’ election, either (a) a number of common units at an issue price equal to either (i) if the common units are listed on a national stock exchange, 93% of the volume weighted average price of such common units for the twenty day period immediately preceding the date of the contribution or (ii) if the common units are not listed on a national stock exchange, the fair market value of such common units as reasonably agreed by us and Holdings or (b) a senior unsecured note of the Partnership in an initial face amount equal to the amount of the contribution by Holdings (an “Investment Note”). If Holdings elects to receive an Investment Note in exchange for a contribution pursuant to the Investment Agreement, such Investment Note will mature on or after November 5, 2019 and bear interest at a rate of 12.5% per annum payable in-kind prior to December 31, 2018 and in cash on or after December 31, 2018. The Investment Notes, if any, will be the unsecured obligation of the Partnership subordinate in right of payment to any of the Partnership’s secured obligations under the Third A&R Revolving Credit Agreement and will contain covenants and events of default no more restrictive than those currently provided in the Third A&R Revolving Credit Agreement.

Pursuant to the Backstop Agreement, if Holdings is unable to satisfy its obligations under the Investment Agreement with cash on hand upon the occurrence of a Partial Investment Trigger or a Full Investment Trigger, the Sponsors have agreed to fund Holdings’ shortfall in providing the Committed Amount by contributing each Sponsor’s respective pro-rata portion of the shortfall to Holdings or, at the election of each Sponsor, directly to us. As consideration for any amounts contributed directly to us by a Sponsor pursuant to the Backstop Agreement, we will issue to such Sponsor the common units or Investment Note that would have otherwise been issued to Holdings under the Investment Agreement with respect to the amount contributed by the Sponsor.

Based upon the Partnership's financial forecast, amendments to the credit agreement (as discussed above), as well as the $15.0 million additional capital commitment from Holdings and the Sponsors, we believe management's executed plans provide the Partnership with sufficient liquidity to fund future operations through at least twelve months from the date that these financial statements were issued.

Holdings Chapter 11 Reorganization

On March 28, 2016, Holdings and certain of its subsidiaries (excluding us, our General Partner and our subsidiaries) filed a pre-packaged plan of reorganization (the “POR”) under Chapter 11 of the U.S. Bankruptcy Code in the Southern District of Texas to restructure its debt obligations and strengthen its balance sheet. Our operations, customers, suppliers, partners and other constituents were excluded from such proceeding. On April 11, 2016, the bankruptcy court confirmed Holdings’ POR, and on April 13, 2016, Holdings and its subsidiaries emerged from bankruptcy with its Lenders being issued 33.34% of the limited partner interests in Holdings in exchange for the elimination of certain funded debt obligations. EIG and Tailwater each contributed $85 million in cash (or $170 million in the aggregate) in exchange for each Sponsor receiving 33.33% of the limited partner interests in Holdings. In addition, Holdings committed to provide us $50 million (the "Contribution Amount") (as part of an equity cure contribution agreement with Holdings that allowed us to cure any default under applicable financial covenants, set forth in our credit agreement at the time, by having Holdings purchase equity interests in or make capital contributions to us), out of the $170 million in new equity contributed to Holdings from the Sponsors, to provide us with liquidity to comply with the applicable financial covenants set forth in our credit agreement at the time.

Distribution Suspension

The board of directors of our General Partner suspended paying a quarterly distribution with respect to the fourth quarter of 2015 and every quarter of 2016 to reserve any excess cash for the operation of our business. The board of directors of our General Partner and our management believe this suspension to be in the best interest of our unitholders and will continue to

Table of contents

evaluate our ability to reinstate the distribution in future periods. Additionally, we are restricted under the fifth amendment to the Third A&R Revolving Credit Agreement from paying a distribution until our Consolidated Total Leverage Ratio is below 5.0. See Notes 2 and 4 to our 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. Due to the common control aspects in the 2015 Holdings Acquisition, the Partnership’s financial results retrospectively include the financial results for the Valley Wells System and the Compression Assets for all periods ending after August 4, 2014, the date that Southcross Energy LLC and TexStar Midstream Services, LP, a Texas limited partnership (“TexStar”), combined pursuant to a contribution agreement in which Holdings was formed (the “Holdings Transaction”). For additional details regarding the 2015 Holdings Acquisition, see Notes 1 and 3 to our consolidated financial statements.

Emerging Growth Company Status

We are an "emerging growth company," as defined in the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). For as long as we are deemed an emerging growth company, we may take advantage of specified reduced reporting and other regulatory requirements that are generally unavailable to other public companies. These provisions include:

- an exemption from the auditor attestation requirement in the assessment of the emerging growth company's internal controls over financial reporting;
- an exemption from the adoption of new or revised financial accounting standards until they would apply to private companies;
- an exemption from compliance with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; and
- reduced disclosure about the emerging growth company's executive compensation arrangements pursuant to the rules applicable to smaller reporting companies.

We have elected to adopt the reduced disclosure requirements described above, except that we have elected to opt out of the exemption that allows emerging growth companies to extend the transition period for complying with new or revised financial accounting standards.

We may take advantage of these provisions until we are no longer an emerging growth company, which will occur on the earliest of:

i. the last day of the fiscal year following the fifth anniversary of our IPO (December 31, 2017);
ii. the last day of the fiscal year in which we have more than $1.0 billion in annual revenues;
iii. the date on which we have more than $700 million in market value of our common units held by non-affiliates; or
iv. the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period.

As defined in Rule 12b-2 of the Securities Exchange Act of 1934, as amended (the "Exchange Act") we meet the criteria to be a smaller reporting company and have elected to use the reporting exemptions of a smaller reporting company in connection with the preparation of this annual report on Form 10-K and the consolidated financial statements as of December 31, 2016.

Table of contents

Ownership Structure

The following table depicts our ownership structure as of December 31, 2016:

Description	Percentage ownership	
Ownership by non-affiliates:		
Public common units	27.7	%
Southcross Holdings LP's ownership:		
Common units	33.4	%
Subordinated units	15.4	%
Class B Convertible Units	21.5	%
General partner interest	2.0	%
Total	100.0	%

Business Strategy

Our principal business objective is to focus on profitability and improving our business operations by increasing the reliability and efficiency of our assets while managing our costs to ensure the ongoing stability of our business. We expect to achieve this objective by pursuing the following business strategies:

- Maintain sound financial practices to ensure our long-term viability. We intend to maintain our commitment to financial discipline, including reduction of leverage on our consolidated balance sheet, which we believe will serve the long-term interests of our unitholders.
- Continue to enhance the profitability of our existing assets. We intend to increase the profitability of our existing asset base by identifying new business opportunities such as adding new natural gas supplies to our existing gathering and processing assets and pursuing new supplies of NGLs for our fractionation facilities. We have seen an increase in drilling activity around our South Texas assets since the second quarter of 2016 which we believe will lead to improved opportunities for us.
- Manage our exposure to commodity price risk. Because natural gas and NGL prices are volatile, we strive to mitigate the impact of fluctuations in commodity prices and to generate more stable cash flows. We have, and will continue to pursue, a contract portfolio that is weighted towards fixed-fee and fixed-spread contracts, which are not directly sensitive to commodity price levels, while minimizing our direct exposure to commodity price fluctuations. Also, we will consider other methods of limiting commodity exposure, including the use of derivative instruments, as appropriate.
- Continue cost savings initiatives. We intend to continue to evaluate and implement cost-saving initiatives, such as consolidation of our Y-grade fractionation, to improve and generate future cash flows.

Competitive Strengths

We believe that we are well-positioned to execute our business strategies successfully by capitalizing on the following competitive strengths:

- Strategically located asset base. The majority of our assets are located in, or within close proximity to, the Eagle Ford Shale region in South Texas, which is one of the most resource rich drilling regions in the U.S. We operate in Mississippi and Alabama. Also, we believe the growth potential of our South Texas assets coupled with the established, long-lived nature of our Mississippi and Alabama assets provide us with the opportunity to generate growth over the next several years. In addition, all of our assets have access to major natural gas market areas.
- South Texas. Our growth opportunities are impacted primarily by natural gas production in the Eagle Ford Shale region. Our Eagle Ford Southcross pipeline catchment area includes multiple prospective production zones, including the Olmos tight sands formation, which overlays the Eagle Ford Shale. Our business activity provides us with relationships with producers in the South Texas region and an understanding of their future development plans and infrastructure needs. In addition, our South Texas systems benefit from access to the large industrial market for both natural gas and NGLs in and around the Corpus Christi area.
- Mississippi and Alabama. We are a leading service provider in the Mississippi and Alabama regions in which we operate. Our assets provide critical supply to our industrial, commercial and power generation customers and the

9

Table of contents

wholesale markets via intrastate and interstate pipeline interconnects. Several of the large, gas-fired power plants across the southern portion of Mississippi access their primary source of natural gas through our system.

- Reliable cash flows underpinned by long-term, fixed-fee and fixed-spread contracts. We provide our services primarily under fixed-fee and fixed-spread contracts, which help to promote cash flow reliability and minimize our direct exposure to commodity price fluctuations.
- Integrated South Texas midstream value chain. We provide a comprehensive package of services to natural gas producers and customers including natural gas gathering, processing, treating, compression and transportation and NGL fractionation and transportation. We believe our ability to move natural gas and NGLs from the wellhead to market provides us with several advantages in competing for new supplies of natural gas. Specifically, the integrated nature of our business allows us to provide multiple services related to a single supply of natural gas and take advantage of incremental opportunities that present themselves along the value chain. Providing multiple services to customers also gives us a better understanding of each customer's needs and the marketplace. In addition to the advantages with our producers and customers, our ability to source and transport natural gas to market also allows us to satisfy our commercial and industrial customers' demand for natural gas. We believe all of these factors provide a competitive advantage relative to companies which do not offer this range of midstream services.
- Experienced and incentivized management and operating teams. Our senior executives have worked in several energy companies. Our executive officers have extensive experience in building, acquiring and managing midstream and other energy assets and are focused on optimizing our existing business and expanding our operations through disciplined development and accretive acquisitions. Many of our field operating managers and supervisors have long-standing experience operating our assets.
- Supportive Sponsors with significant industry expertise. Our Sponsors are the principal owners of Holdings, which is the owner of our General Partner and the indirect beneficial owner of 54.6% of our common units, and have substantial experience as private equity investors in the energy and midstream sectors. Our Sponsors' investment professionals have deep experience in identifying, evaluating, negotiating and financing acquisitions and investments in the midstream sector. We believe that our Sponsors provide us with strategic guidance, financial expertise and capital support that enhance our ability to grow our asset base and cash flow.

Our Assets and Operations

Our assets consist of gathering systems, intrastate pipelines, two natural gas processing plants, one fractionation facility, 20 compressor stations and a treating system. Our operations are managed as and presented in one reportable segment.

The following tables provide information regarding our assets as of and for the year ended December 31, 2016:

	As of December 31, 2016	Year Ended December 31, 2016
Gathering systems and intrastate pipelines	Miles	Average throughput volumes of natural gas (MMcf/d)
South Texas	2,011	530
Mississippi/Alabama	1,097	160
Total	3,108	690

	As of December 31, 2016	Year Ended December 31, 2016
Processing plants	Approximate design of gas	Average volume of

	processing capacity (MMcf/d)	processed gas (MMcf/d)
Gregory (1)	—	23
Conroe (2)	—	21
Woodsboro	200	166
Lone Star	300	123
Total	500	333

Table of contents

Fractionation plants	As of December 31, 2016 Approximate design of fractionation capacity (Bbls/d)	Year Ended December 31, 2016 Average volume of NGLs sold from output (Bbls/d)
Gregory (1)	—	—
Bonnie View	22,500	12,470
Total	22,500	12,470

Field Compression Stations	As of December 31, 2016 Approximate design of compression horsepower
Gregory (1)	4,480
Barracuda	5,440
Comet	5,520
Corvair	2,760
Cyclone	2,760
El Dorado	8,280
Lancaster Plant	5,700
Oppenheimer	760
Scott North	637
Urban	500
Valley Wells Treater	21,305
Other	24,016
Total	82,158

(1) On August 4, 2016, the Gregory facility was idled and converted to a compressor station by December 31, 2016. The assets at the Gregory facility that will not be used as part of the compressor station will be sold or scrapped. The gas previously processed at the Gregory facility was re-routed through our integrated system and is now being processed at our Woodsboro processing facility.

(2) On July 29, 2016, we notified our producers that the Conroe plant would be shut down. The Conroe plant was shut down by December 31, 2016 and currently is being dismantled.

In connection with our acquisition of TexStar Rich Gas System, we acquired equity interests in three joint ventures, including T2 Eagle Ford Gathering Company LLC (“T2 Eagle Ford”), T2 LaSalle Gathering Company LLC (“T2 LaSalle”) and T2 EF Cogeneration Holdings LLC (“T2 Cogen”), which operate pipelines and a cogeneration facility located in South Texas. We indirectly own a 50% interest in T2 Eagle Ford, a 50% interest in T2 Cogen and a 25% interest in T2 LaSalle. T2 Cogen operates two gas powered turbines that buy fuel from related parties and charges such parties based on monthly electrical activity. The following table provides information regarding our pipeline joint venture investments, T2 Eagle Ford and T2 LaSalle, for the year ended December 31, 2016:

Joint venture pipelines	As of December 31, 2016 Miles

		Leased Capacity	Average throughput volumes of natural gas (MMcf/d)[1]
Dimmit	49	50 %	35
LaSalle	63	25 %	236
Choke Canyon	72	50 %	260
Residue Header	76	50 %	269
Total	260		

(1) Average throughput volumes of natural gas calculated for the entire year ended December 31, 2016.

We derive revenue primarily from fixed-fee and fixed-spread arrangements. Our contracts vary in duration from one month to several years and the duration and pricing of our contracts vary depending upon several factors, including our

Table of contents

competitive position, our acceptance of risks associated with longer-term contracts, and our desire to recoup over the term of a contract any capital expenditures that we are required to incur in order to provide service to our customers. We continually seek new sources of natural gas supply and end use markets to increase the gas throughput volume on our gathering and pipeline systems and through our processing plants and compression assets.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. Our NGL products and the demand for these products are affected as follows:

- Ethane. Ethane is typically supplied as purity ethane or as part of an ethane-propane mix. Ethane is used primarily in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane typically is extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.

- Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. In addition, U.S. demand for propane as a heating fuel is affected significantly by weather conditions. The volume of propane sold in the U.S. typically is at its highest during the six-month peak heating season of October through March. Demand for propane may be reduced during periods of warmer-than-normal weather.

- Normal Butane. Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas and in the production of ethylene and propylene. U.S. demand for normal butane as a refined product blending component is at its highest in September through February. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene could affect demand for normal butane adversely.

- Isobutane. Isobutane is used predominantly in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement could reduce demand for isobutane.

- Natural Gasoline. Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could affect demand for natural gasoline adversely.

NGLs and products produced from NGLs also compete with global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could affect demand for the services we provide adversely as well as NGL prices, which would impact negatively our results of operations and financial condition.

South Texas

The assets in our South Texas region are located between Montgomery County which is north of Houston, and Webb and Dimmit Counties near the Texas-Mexico border. As of December 31, 2016, these assets consisted of approximately 2,011 miles of pipeline ranging in diameter from 2 to 24 inches, our Woodsboro processing plant, our Bonnie View NGL fractionation facility, our Lone Star processing plant, our Valley Wells System and 20 compression stations.

The majority of our pipelines in South Texas feed rich gas from multiple producing fields, including the Eagle Ford Shale, to our processing and NGL fractionation facilities at Lone Star, Woodsboro and Bonnie View. The residue gas pipelines from our processing plants and the remaining pipelines in lean gas service in South Texas are used to serve multiple industrial and electric generation customers, and to deliver gas to a number of intrastate and interstate pipelines. Holdings owns approximately 600 miles of gathering pipeline in Frio and LaSalle counties and the Robstown fractionator ("Robstown") to which all or our assets are connected.

Our Woodsboro processing plant is a 200 MMcf/d cryogenic processing plant located in Refugio County, Texas. Our Bonnie View NGL fractionation plant, also in Refugio County, Texas has a capacity of 22,500 Bbls/d. In June 2015, we completed the NGL pipelines, which include a Y-grade pipeline that connects our Woodsboro processing facility to Robstown

Table of contents

and a propane pipeline from our Bonnie View fractionator to Robstown. The installation of the NGL pipelines resulted in our ability to sell incremental Y-grade to Holdings and mitigated the financial impact of the capacity reductions at Bonnie View.

Our Lone Star processing plant is a 300 MMcf/d cryogenic processing plant located in Bee County, Texas, and was acquired from TexStar in August 2014. The plant is interconnected with other South Texas rich gas supply basins and Woodsboro via our Bee Line pipeline which was placed into service in 2013.

Our Gregory processing plant was a cryogenic processing plant comprised of two units collectively having a total capacity of 135 MMcf/d, and a fractionator having total capacity of 4,800 BBls/d. This plant processed natural gas from both a local gathering system and from sources elsewhere on our South Texas pipeline systems until we determined, as part of cost-cutting initiatives, to idle the plant in August 2016 and shut it down and convert the site into a compressor station by December 31, 2016. The natural gas that previously was sent to Gregory has been diverted to our newer, more efficient, Woodsboro plant. The conversion of the Gregory plant resulted in operating expense and capital expense savings.

On January 20, 2015, our Gregory processing plant experienced a fire which caused damage to one of our two processing plants, taking all 135 MMcf/d of processing capacity temporarily out of service. In February 2015, we started one of the Gregory plants and operated it until it was permanently idled in August 2016. In December 2016, we reached a settlement related to the Gregory processing plant fire with our insurance carriers. We received the payment of $2.0 million from our insurance carriers in the first quarter of 2017 and used a portion of the proceeds to pay down on our term loan.

Our Conroe processing plant and gathering system is a 50 MMcf/d cryogenic natural gas plant. The processing plant and gathering system operated together north of Houston in Montgomery County, Texas to gather and process natural gas. We had a mixture of fixed-fee and percent of proceeds processing contracts with producers, under which the majority of the residue gas from the Conroe plant was returned to the producers for gas lift purposes. We sold the remaining residue gas and NGLs to unaffiliated parties.

We decided to shut down the Conroe facility as part of company-wide cost-cutting initiatives. On July 29, 2016, we notified our producers that the Conroe plant was going to be shut down by year end. As of December 31, 2016, the Conroe plant was shut down and currently is being dismantled.

Our Valley Wells System, located in LaSalle County, Texas, 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.

Mississippi and Alabama

The assets in our Mississippi region are located principally in the southern half of the state and comprise the largest intrastate pipeline system in Mississippi. The Mississippi assets consist of approximately 605 miles of pipeline, ranging in diameter from 2 to 20 inches with an estimated design capacity of 345 MMcf/d, and two treating plants. Our system throughput volumes in Mississippi are affected by both on-system gas production volumes and customers' demand for gas. The system has the capability to receive natural gas from three unaffiliated interstate pipelines—Southeast Supply Header, Southern Natural Gas Company and Texas Eastern Company—to supplement supply on the system or to market gas off the system.

The assets in our Alabama region are located in northwest and central Alabama and consist of 492 miles of natural gas gathering and transmission pipelines ranging from 2 to 16 inches in diameter with an estimated design capacity of 375 MMcf/d. The primary gas supply to the system is coal bed methane gas from the Black Warrior Basin with incremental volumes gathered from conventional gas wells. The system receives natural gas from unaffiliated interstate pipelines and services markets along the system.

Competition

The natural gas gathering, compression, processing, transportation and marketing business and the NGL fractionation business are highly competitive. Our competitors include other midstream companies, producers and intrastate and interstate pipelines. Competition for natural gas volumes is based primarily on commercial terms, reliability, service levels, flexibility, access to markets, location, available capacity, connection costs and fuel efficiencies. Our principal competitors are DCP Midstream LLC, Energy Transfer Partners, L.P., Enterprise Products Partners LP, Boardwalk Pipeline Partners, LP, Kinder Morgan Inc. and Targa Pipeline Partners, L.P.

In addition to competing for natural gas supply volumes, we face competition for customer markets in selling residue gas and NGLs. Competition is based primarily on the proximity of pipelines to the markets, price and assurance of supply.

Table of contents

Customers and Concentration of Credit Risk

Our markets are in Texas, Alabama and Mississippi and we have a concentration of trade accounts receivable due from customers engaged in the purchase and sale of natural gas and NGL products, and other services. These concentrations of customers may affect our overall credit risk as these customers may be affected similarly by changes in economic, regulatory or other factors. We analyze customers' historical financial and operational information prior to extending credit.

Our top ten customers accounted for 53.5% of our revenue for the year ended December 31, 2016. Due to the continued volatility of commodity prices, some of our customers may experience material financial and liquidity issues. For the years ended December 31, 2016 and 2015, we did not experience significant nonpayment for services. We had no allowance for uncollectible accounts receivable at December 31, 2016. We recorded an allowance for uncollectible accounts receivable of $0.1 million at December, 31, 2015 which was written off in 2016.

Governmental Regulation

We are subject to regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") pursuant to the Natural Gas Pipeline Safety Act of 1968 (the "NGPSA"), and the Pipeline Safety Improvement Act of 2002 (the "PSIA"), which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. crude oil and natural gas transmission pipelines in "high-consequence areas". PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in "high consequence areas," such as high population areas. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"), reauthorized funding for federal pipeline safety programs, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016, signed on June 22, 2016, provides funding for the continuation of pipeline safety program revisions initiated under the 2011 Pipeline Safety Act and requires PHMSA to set minimum safety standards for underground natural gas storage facilities, authorizes emergency order authority, designates marine coastal areas as unusually environmentally sensitive to pipeline failures and requires additional safety studies that could result in new regulatory requirements for existing pipelines.

PHMSA issued a separate rule that was finalized in January 2017 and is due to be effective on March 24, 2017 that would impose pipeline incident prevention and response measures on pipeline operators. The effective date of this final rule is currently uncertain due to a regulatory freeze implemented by the Trump administration on January 20, 2017. PHMSA also recently published an advisory bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. We have performed hydrotests of our facilities to establish the maximum allowable operating pressure and do not expect that any final rulemaking by PHMSA regarding verification of maximum allowable operating pressure would materially affect our operations or revenue. We believe our records relating to allowable maximum operating pressure to be reliable, traceable, verifiable and complete.

Additionally, the National Transportation Safety Board has recently recommended that the PHMSA make a number of changes to its rules, including removing an exemption from most safety inspections for natural gas pipelines installed before 1970. While we cannot predict the outcome of proposed legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. Further legislative and regulatory changes may also result in higher penalties for the violation of federal pipeline safety regulations. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the costs of compliance associated with such requirements, but we regularly inspect our pipelines and third parties assist us in interpreting the results of the inspections.

States largely are preempted by federal law from regulating pipeline safety for interstate lines but most states are certified by the U.S. Department of Transportation (the "DOT") to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our natural gas and natural gas products pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

Table of contents

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (the "OSHA"), and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry; the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens; the OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals; the Environmental Protection Agency's (the “EPA”) Chemical Accident Prevention Provisions, also known as the Risk Management Plan requirements, which are designed to prevent the accidental release of toxic, reactive, flammable or explosive materials; and the Department of Homeland Security Chemical Facility Anti-Terrorism Standards, which are designed to regulate the security of high-risk chemical facilities. We do not believe that compliance with these regulations will have a material adverse effect on our business, financial position or results of operations or cash flows.

Further, exposure to gas containing certain levels of hydrogen sulfide, referred to as sour gas, can be harmful, even fatal, to humans. Some of the gas processed at our sour gas treating and processing facility, as part of the Valley Wells System, contains high levels of hydrogen sulfide. We do not believe that compliance with the applicable federal and state environmental, health and safety laws will have a material adverse effect on our business, financial position or results of operations or cash flows.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Intrastate Pipelines

Our transmission lines are subject to state regulation of rates and terms of service. In Texas, the regulatory system allows rates to be negotiated on a customer-by-customer basis and are subject to a complaint-based review process. In rare circumstances, as allowed by statute, regulators may initiate a rate review. Although Texas does not have an "open access" requirement, there is a "non-discriminatory access" requirement, which is subject to a complaint-based review. In Mississippi and Alabama, the regulatory systems allow special contracts that are negotiated on a customer-by-customer basis for approval by the applicable state commission.

Section 311 Pipelines

Intrastate transportation of natural gas is largely regulated by the state in which such transportation takes place. Several of our intrastate pipeline subsidiaries, Southcross CCNG Transmission Ltd., Southcross Gulf Coast Transmission Ltd., Southcross Mississippi Pipeline, L.P., TexStar Transmission, LP, Southcross Nueces Pipelines LLC and Southcross Alabama Pipeline LLC, also provide interstate transportation services. The rates, terms and conditions of such services are subject to the Federal Energy Regulatory Commission ("FERC") jurisdiction under Section 311 of the Natural Gas Policy Act ("NGPA"), and Part 284 of FERC's regulations. Pipelines providing certain transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis. The NGPA regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline or a local distribution company or LDC served by an interstate natural gas pipeline. Under Section 311, rates charged for intrastate transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. The rates under Section 311 approved by FERC are maximum rates and we may negotiate at or below such rates depending on the market. Currently, FERC reviews our rates every five years and such rates may increase or decrease as a result of such reviews. The next rate review occurs in 2017. The terms and conditions of service set forth in the intrastate pipeline's statement of operating conditions are also subject to FERC's review and approval. In the future, should FERC determine not to authorize rates which fully recover our costs of service, our business may be adversely affected. Failure to observe the service limitations applicable to transportation and storage services under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and/or failure to comply with the terms and conditions of service established in the pipeline's FERC-approved statement of operating conditions could result in alteration of jurisdictional status, and/or the imposition of administrative, civil and criminal remedies or sanctions.

Hinshaw Pipelines

Similar to intrastate pipelines, Hinshaw pipelines, by definition, also operate within a single state. We have a Mississippi pipeline segment that is categorized as a Hinshaw pipeline. Also, similar to pipelines operating under Section 311 of the NGPA, Hinshaw pipelines can receive gas from outside their state without becoming subject to the jurisdiction of FERC under the Natural Gas Act ("NGA"). Specifically, Section 1(c) of the NGA exempts from FERC's NGA jurisdiction those pipelines that transport gas in interstate commerce if (1) they receive natural gas at or within the boundary of a state, (2) all the gas is

Table of contents

consumed within that state and (3) the pipeline is regulated by a state commission. Following the enactment of the NGPA, FERC issued Order No. 63 authorizing Hinshaw pipelines to apply for authorization to transport natural gas in interstate commerce in the same manner as intrastate pipelines operating pursuant to Section 311 of the NGPA. Hinshaw pipelines frequently operate pursuant to blanket certificates to provide transportation and sales service under FERC's regulations.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. Although FERC has not made a formal determination with respect to all of our facilities we believe to be gathering facilities, we believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there have been no adverse effects to our systems due to these regulations.

Market Behavior Rules; Reporting Requirements

Interstate natural gas pipelines regulated by FERC are required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC’s standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates. FERC’s market oversight and transparency regulations require regulated entities to submit reports of, among other things, threshold purchases or sales of natural gas and publicly post certain information on scheduled volumes. FERC’s market manipulation regulations, promulgated pursuant to the Energy Policy Act of 2005 (the “EPAct 2005”), make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 (“NGPA”) to give FERC authority to impose civil penalties for violations of these statutes up to $1.0 million per day per violation for violations occurring after August 8, 2005. The maximum penalty authority established by the statute has been and will continue to be adjusted periodically for inflation. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

State Utility Regulation

Some of our operations in Texas are specifically subject to the Texas Gas Utility Regulatory Act, as implemented by the Railroad Commission of Texas ("RRC"). Generally, the RRC has authority to ensure that rates charged for natural gas sales or transportation services are just and reasonable. Our gas utilities, Southcross CCNG Gathering Ltd., Southcross CCNG Transmission Ltd. and Southcross Gulf Coast Transmission Ltd., Southcross Nueces Pipelines LLC, FL Rich Gas Utility and TexStar Transmission, LP are required to file gas tariffs and Southcross NGL Pipeline Ltd. has filed NGL tariffs with the RRC.

Table of contents

In Mississippi, the Mississippi Public Service Commission considers Southcross Mississippi Industrial Gas Sales, L.P. a utility and it is necessary to get contract approval for negotiated contracts.

In Alabama, the Alabama Public Service Commission ("APSC") requires a gas utility to file "special negotiated contracts" with the APSC for approval, which includes our Southcross Alabama Pipeline LLC.

Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas and NGLs

The transportation of natural gas in interstate commerce has been regulated by FERC under the NGA, the NGPA and regulations issued under those statutes and the transportation of NGLs in interstate commerce has been regulated by FERC under the Interstate Commerce Act. Historically the price, terms and conditions of the sale of natural gas at wholesale in interstate commerce was regulated by FERC, but the sale of NGLs was not regulated. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

The price at which we sell natural gas is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Sales of NGLs are currently not regulated and are made at negotiated prices. While sales by producers of natural gas and sales of NGLs can currently be made at market prices, Congress could enact price controls in the future.

As discussed above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting interstate natural gas pipelines and those initiatives may also affect the intrastate transportation of natural gas both directly and indirectly.

Anti-terrorism Measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security (the "DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establishes chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. In addition, in August 2014, DHS issued an advanced notice of proposed rulemaking designed to identify ways to make the Chemical Facility Anti-Terrorism Standards program more effective. Covered facilities that are determined by DHS to pose a high level of security risk are required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, record-keeping and protection of chemical-terrorism vulnerability information. Three of our facilities (the Gregory, Conroe and Woodsboro plants) have more than the threshold quantity of listed chemicals; therefore, a "Top Screen" evaluation was submitted to the DHS. The DHS reviewed this information and determined that none of the facilities are considered high-risk chemical facilities.

Cyber Security Measures

While we are currently not subject to governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered in the U.S. Congress and by U.S. Executive Branch departments and agencies, including the DHS, and we may become subject to such standards in the future. Currently, we are implementing our own cyber security programs and protocols; however, we cannot guarantee their effectiveness. A significant cyber-attack could have a material effect on our operations and those of our customers.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for natural gas gathering, processing, treating, compression and transportation, and for NGL fractionation and transportation services is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply

Table of contents

with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate or imposing additional costs on our operations;
- managing or otherwise regulating the way we handle and secure toxic, reactive, flammable or explosive materials to prevent or minimize the release of such materials;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- delaying system modification or upgrades during permit reviews;
- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former or third-party operations; and
- enjoining the operations of facilities deemed to be in non-compliance with permits issued pursuant to or permit requirements imposed by such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other materials into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and, thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, process, treat, compress and transport natural gas and fractionate and transport NGLs. We cannot provide assurance, however, that future events, such as changes in existing laws, regulations, or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation, release and disposal of hazardous substances and solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where these materials may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA" or the "Superfund Law"), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to cleanup sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act (the "RCRA"), and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate little hazardous waste; however, it is possible that certain non-hazardous waste, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and, therefore, be subject to more rigorous and costly management and disposal requirements. Moreover, from time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for non-hazardous wastes, including natural gas wastes. Any such changes

Table of contents

in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses or otherwise impose limits or restrictions on our operations or those of our customers.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Oil Pollution Act

In 1991, the EPA adopted regulations under the Oil Pollution Act (the "OPA"). These oil pollution prevention regulations, as amended several times since their original adoption, require the preparation of a Spill Prevention Control and Countermeasure Plan ("SPCC") for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the U.S. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility's operations comply with the requirements. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. We believe that none of our facilities is materially adversely affected by such requirements.

Air Emissions

Our operations are subject to the federal Clean Air Act (the "CAA"), and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations and processing plants, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We and our customers may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements.

On January 30, 2013, the EPA finalized amendments to new regulations under the CAA to control emissions of hazardous air pollutants from stationary reciprocating internal combustion engines and stationary internal combustion engines. The scope of applicability for most of our engines is the requirement to follow a prescribed maintenance plan or comply with already existing New Source Performance Standard. Although this rule has been the subject of litigation and may be revised, we do not anticipate that the revisions will have a material adverse effect on our operations. The few engines we do have that are subject to the control and compliance provisions of National Emission Standards for Hazardous Air Pollutants Standard are new engines which meet the emissions limitations therein.

On April 17, 2012, the EPA approved final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. This rule addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. For new or reworked hydraulically-fractured gas wells, the final rule requires controlling emissions through flaring until 2015, when the rule requires the use of reduced emission, or "green", completions. The rule also established specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. On August 5, 2013, the EPA finalized updates to the 2012 performance standards for emissions of volatile organic compounds (“VOCs”) from storage tanks used in oil and natural gas production and transmission, which, among other things, adjusted reporting requirements and phased in the date by which storage tanks must install VOC controls. On June 3, 2016, the EPA issued additional regulations to control emissions of methane and VOCs from various oil and natural gas operations. Compliance with these rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Table of contents

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. and impose requirements affecting our ability to conduct construction activities in waters and wetlands. In May 2015, the EPA issued a final rule that attempts to clarify the federal jurisdictional reach over waters of the U.S., but this rule has been stayed nationwide by the U.S. Sixth Circuit Court of Appeals. On January 13, 2017, the U.S. Supreme Court agreed to review the Sixth Circuit's finding that it has jurisdiction to hear challenges to the rule. To the extent the rule expands the scope of the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In May 2015, the EPA issued a final rule that, if upheld in the federal court system, may expand the federal jurisdictional reach over waters of the United States and may result in increased costs and delays in obtaining permits for dredge and fill activities. We believe that compliance with existing permits and compliance with foreseeable new permit requirements under the Clean Water Act and state counterparts will not have a material adverse effect on our business, financial condition, results of operations or cash flow.

Endangered Species

The Endangered Species Act (the "ESA") restricts activities that may affect endangered or threatened species or their habitats. The current listing of species as threatened or endangered has not had a material adverse effect on our business, financial condition, results of operations or cash flow. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development activity in the affected areas.

Climate Change

The EPA has adopted regulations under existing provisions of the CAA that require certain large stationary sources to obtain Prevention of Significant Deterioration ("PSD") pre-construction permits and Title V operating permits for greenhouse gas ("GHG") emissions which does not currently apply to our facilities. In addition, in September 2009, the EPA issued a final rule requiring the monitoring and reporting of GHG emissions from certain large GHG emissions sources. Our Gregory, Woodsboro, Bonnie View, Conroe, Lone Star and El Dorado facilities are or will be required to report under this rule. This reporting rule was expanded in November 2010 to include petroleum and natural gas facilities, including certain natural gas transmission compression facilities, and again in October 2015 to include onshore petroleum and natural gas gathering and boosting activities and natural gas transmission pipelines. We have submitted the reports required under the reporting rule on a timely basis and have adopted procedures for future required reporting. In addition, on June 3, 2016, the EPA issued regulations to control emissions of methane, a GHG, and VOCs from various oil and natural gas operations. Compliance with these rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

While Congress has from time to time considered legislation to reduce emissions of GHGs, the prospect for adoption of significant legislation at the federal level to reduce GHG emissions is perceived to be low at this time. Several states have also implemented programs to reduce and/or monitor GHG emissions. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, including our current or future customers, which

could thereby reduce demand for our midstream services.
In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce GHG emissions. We continue to monitor the international efforts to address climate change. To the extent the United States and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse direct or indirect effect on our business.
Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing

Table of contents

with higher GHG emitting energy sources, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems and our insurance may not cover all associated losses. We are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Employees

Currently, we do not have any employees. We rely solely on officers and employees of our General Partner to operate and manage our business. Our General Partner employed 268 full-time employees as of December 31, 2016. None of these employees are covered by collective bargaining agreements, and our General Partner considers its employee relations to be good.

Available Information

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to such reports, as well as other documents electronically with the Securities Exchange Commission (the "SEC") under the Exchange Act. From time-to-time, we also may file registration and related statements pertaining to equity or debt offerings. We provide access free of charge to all of these materials, as soon as reasonably practicable after such materials are filed with, or furnished to the SEC, on our website located at www.southcrossenergy.com. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

The public may obtain such reports from the SEC's website at www.sec.gov. The public may also read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549 on official business days during the hours of 10 a.m. to 3 p.m. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-(800) SEC-0330.

Table of contents

Item 1A. Risk Factors

You should carefully consider the following risk factors, together with all of the other information included in this Form 10-K, when deciding whether to invest in us. Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should be aware that the occurrence of any of the events described in this report could have a material adverse effect on our business, financial condition, results of operations and cash flows. In such event, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. The following risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we deem to be immaterial also may materially adversely affect our business, results of operations and financial condition and our ability to make distributions.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our General Partner, to enable us to pay the minimum quarterly distribution, or any distribution, to our unitholders.

We may not have sufficient cash from operations, following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our General Partner, each quarter to enable us to reinstate the minimum quarterly distribution. For example, in January 2016 the board of directors of our General Partner suspended paying a quarterly distribution with respect to the fourth quarter of 2015 and every quarter of 2016 and instead, based on current conditions, to reserve any excess cash for the operation of our business. Additionally, we currently have restrictions on paying a cash distribution until our Consolidated Total Leverage Ratio is below 5.0 to 1.0. The board of directors of our General Partner and our management believe this suspension to be in the best interest of our unitholders and will continue to evaluate the Partnership's ability to reinstate the distribution in future periods. Our decision to reserve all of our cash on hand for allowed purposes and not distribute it may significantly impact our unitholders, as well as our business and operations. The market value of our units may remain depressed or decline further unless and until we resume a distribution. In addition, refinancing or restructuring of our debt may require us to accept covenants that may restrict our ability to reinstate distributions. External perceptions of the health of our business and our liquidity also may be impacted, which could limit further our ability to access capital markets, cause our vendors to tighten our credit terms and cause a strain in our relationship with customers and other business partners. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volume of natural gas we gather, process, treat, compress and transport and the volume of NGLs we fractionate and transport;
- the level of production of, and the demand for, crude oil, natural gas and NGLs and the market prices of crude oil, natural gas and NGLs;
- damage to pipelines, facilities, plants, related equipment and surrounding properties caused by hurricanes, earthquakes, floods, fires, severe weather, explosions and other natural disasters and acts of terrorism including damage to third-party pipelines or facilities upon which we rely for transportation and processing services;
- outages at the processing or NGL fractionation facilities owned by us or third parties, whether caused by mechanical failure resulting from maintenance, construction or otherwise;
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise;
- prevailing economic and market conditions;
- realized prices received for natural gas and NGLs;
- fixed-fees associated with our services;
- the market prices of natural gas and NGLs relative to one another, which affects our processing margins;
- capacity charges and volumetric fees associated with our transportation services;
- the level of competition from other midstream energy companies in our geographic markets;
- the level of our operating, maintenance, general and administrative costs;

22

Table of contents

- regulatory action affecting the supply of, or demand for, natural gas, the maximum transportation rates we can charge on our pipelines, our existing contracts, our operating costs or our operating flexibility; and
- the financial health of our parent company and its ability to pay amounts owed to us on a timely basis.

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

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our General Partner; and
- other business risks affecting our cash levels.

Because of the natural decline in production from existing wells in our areas of operation, our success depends in part on producers growing production and replacing declining production and also on our ability to obtain new sources of natural gas. Any decrease in the volumes of natural gas that we gather, compress, process, treat or transport or in the volumes of NGLs that we fractionate or transport could adversely affect our business and operating results.

The natural gas volumes that support our business depend on the level of production from natural gas wells connected to our systems, which may be less than expected and will naturally decline over time. As a result, our cash flows associated with these wells also will decline over time. In order to maintain or increase throughput levels on our systems, we must obtain new sources of natural gas. The primary factors affecting our ability to obtain non-dedicated sources of natural gas include (i) the level of successful drilling activity in our areas of operation, (ii) our ability to compete for volumes from successful new wells and (iii) our ability to compete successfully for volumes from sources connected to other pipelines.

We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected crude oil, natural gas and NGL prices;
- demand for crude oil, natural gas and NGLs;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of crude oil and natural gas reserves. Drilling and production activity generally decreases as natural gas, crude oil or NGL prices decrease. Declines in natural gas, crude oil or NGL prices could have a negative impact on exploration, development and production activity, and sustained low prices could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation could lead to reduced utilization of our assets.

Natural gas, crude oil and NGL prices declined significantly in the second half of 2014 and have been negatively affected by a combination of factors, including weakening demand, increased production, the decision by the Organization of Petroleum Exporting Countries to keep production levels unchanged and a strengthening in the U.S. dollar relative to most other currencies. Given the historical volatility of crude oil prices, there remains a risk that prices could further deteriorate due to increased domestic production, slowing economic growth rates in various global regions and/or the potential for significant supply and demand imbalances.

The decline in natural gas, crude oil and NGL prices has negatively impacted exploration, development and production activity, and the sustained low prices of any of these commodities could lead to a material decrease in such activity. Certain of our producers and other suppliers are tied to crude oil wells, and any sustained reduction in exploration or production activity in our areas of operation, whether related to crude oil, natural gas or NGLs, or a combination of them, could lead to reduced utilization of our assets, including the volume of natural gas flowing on our system.

Because of these and other factors, even if natural gas and liquid reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, those reductions could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

We do not obtain independent evaluations of natural gas and liquid reserves connected to our gathering and transportation systems on a regular or ongoing basis; therefore, in the future, volumes of natural gas on our systems could be less than we anticipate.

We do not obtain independent evaluations of the natural gas reserves connected to our systems on a regular or ongoing basis because our producer customers are often unwilling to share this information for competitive reasons. Accordingly, we do not have independent estimates of total reserves dedicated to some or all of our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering and transportation systems are less than we anticipate and we are unable to secure additional sources of natural gas, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our success depends on drilling activity by customers and our ability to attract and maintain customers in a limited number of geographic areas.

A significant portion of our assets are located in the Eagle Ford Shale region, and we intend to focus our future capital expenditures largely on developing our business in this area. As a result, our financial condition, results of operations and cash flows are significantly dependent upon the demand for our services in this area. Due to our focus on this area, an adverse development in natural gas production from this area, such as decreased development or production activity, would have a significantly greater impact on our financial condition and results of operations than if we spread expenditures more evenly over a wider geographic area.

Our failure to execute effectively on major development projects could result in delays and/or cost over-runs, limitations on our growth and negative effects on our operating results, liquidity and financial position.

We are engaged from time to time in the planning and construction of development projects, some of which may take a number of months before commercial operation. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Also, legislative or regulatory intervention may create limits or prohibit our ability to perform desired capital projects. Delays in the completion of these types of projects could have a material adverse effect on our business, financial condition, results of operations and liquidity. Estimating the timing and expenditures related to these development projects is complex and subject to variables that can increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and capital position could be adversely affected. This level of development activity requires effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls.

Energy prices are volatile, and a change in these prices in absolute terms, or an adverse change in energy prices, particularly natural gas and NGLs relative to one another, could adversely affect our gross operating margin and cash flow and our ability to make cash distributions to our unitholders.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. In the past, the prices of natural gas, NGLs and other commodities have been extremely volatile, and we expect this volatility to continue. Our future cash flow will be materially adversely affected if we experience significant, prolonged pricing deterioration.

The markets for and prices of natural gas, NGLs and other commodities depend on factors that are beyond our control. These factors include the supply of and demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- worldwide economic conditions;

Table of contents

- worldwide political events, including actions taken by foreign oil and natural gas producing nations;
- worldwide weather events and conditions, including natural disasters and seasonal changes;
- the levels of domestic production and consumer demand;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation;
- fluctuations in demand from electric power generators and industrial customers; and
- the anticipated future prices of crude oil, natural gas, NGLs and other commodities.

Our exposure to direct commodity price risk and volatility in costs to market products may vary.

We currently generate a large portion of our revenues pursuant to fixed-fee contracts under which 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 the value of the underlying natural gas or NGLs. Consequently, this portion of our existing operations and cash flows have limited direct exposure to commodity price levels. Although we intend to enter into similar fixed-fee contracts with new customers in the future, our efforts to obtain such contractual terms may not be successful. We may acquire or develop additional midstream assets or change the arrangements under which we process our volumes. These changes may also impact our transportation and gathering costs in a manner that increases our exposure to commodity price risk. Extended or future exposure to the volatility of crude oil and natural gas prices could have a material adverse effect on our business, results of operations and financial condition and our ability to make distributions.

In addition, another large portion of our revenues is generated pursuant to fixed-spread contracts under which we strive to buy and sell equal volumes of natural gas and NGLs at prices based upon the same index price of the commodity. Our ability to do this is based upon a number of factors, including willingness of customers to accept the same index as a basis, physical differences in geography, product specifications and ability to market products at the anticipated differential from the pricing index.

Unexpected volume changes due to production variability or to gathering, plant or pipeline system disruptions may increase our exposure to commodity price movements.

We sell processed natural gas to third parties at plant tailgates, pipeline pooling points or at inlet meters to the sites of industrial and utility customers. These sales may be interrupted by disruptions to volumes anywhere along the system. We attempt to balance sales with volumes supplied, but unexpected volume variations due to production variability or to gathering, plant or pipeline system disruptions may expose us to volume imbalances which, in conjunction with movements in commodity prices, could materially impact our income from operations and cash flow.

We may not successfully balance our purchases and sales of natural gas, which would increase our exposure to commodity price risks.

We purchase from producers and other suppliers a substantial amount of the natural gas that flows through our pipelines and processing facilities for sale to third parties, including natural gas marketers and others.

We are exposed to fluctuations in the price of natural gas through volumes sold pursuant to commodity-sensitive arrangements and, to a lesser extent, through volumes sold pursuant to our fixed-spread contracts.

In order to mitigate our direct commodity price exposure, we typically attempt to balance our natural gas sales with our natural gas purchases on an aggregate basis across all of our systems. We may not be successful in balancing our purchases and sales, and as such may become exposed to fluctuations in the price of natural gas. Our overall net position with respect to natural gas can change over time and our exposure to fluctuations in natural gas prices could materially increase, which in turn could result in increased volatility in our revenue, gross operating margin and cash flows.

Although we enter into back-to-back purchases and sales of natural gas in our fixed-spread contracts in which we purchase natural gas from producers or suppliers at receipt points on our systems and simultaneously sell a similar volume of natural gas at delivery points on our systems, we may not be able to mitigate all exposure to commodity price risks. Any of

Table of contents

these actions could cause our purchases and sales to become unbalanced. If our purchases and sales are unbalanced, we will face increased exposure to commodity price risks, which in turn could result in increased volatility in our revenue, gross operating margin and cash flows.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with other similarly sized midstream companies in our areas of operation. Some of our competitors are large companies that have greater financial, managerial and other resources than we do. In addition, some of our competitors have assets in closer proximity to natural gas supplies and have available idle capacity in existing assets that would not require new capital investments for use. Our competitors may expand or construct gathering, compression, treating, processing or transportation systems or NGL fractionation facilities that would create additional competition for the services we provide to our customers. In addition, our customers may develop their own gathering, compression, treating, processing or transportation systems or NGL fractionation facilities in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flow could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our gathering, processing and transportation contracts subject us to contract renewal risks.

We gather, purchase, process, treat, compress, transport and sell most of the natural gas and NGLs on our systems under contracts with terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenue, gross operating margin and cash flows could decline and our ability to make cash distributions to our unitholders could be materially and adversely affected.

We depend on a relatively limited number of customers.

A significant percentage of our revenue is attributable to a relatively limited number of customers. Our top ten customers accounted for 53.5% of our revenue for the year ended December 31, 2016. We have gathering, processing, transportation and/or sales contracts with each of these customers of varying duration and commercial terms. If we are unable to renew our contracts with one or more of these customers on favorable terms, we may not be able to replace any of these customers in a timely fashion, on favorable terms or at all. In addition, many of our customers are oil and gas companies that are facing liquidity constraints in light of the current commodity price environment and may be disproportionately affected by such constraints as compared to larger, better capitalized companies. This concentration of our customers in the energy industry may impact our overall exposure to credit risk as customers may be affected similarly by prolonged changes in economic and industry conditions. If a significant number of our customers experience a prolonged business decline or disruptions or enter into bankruptcy, we will incur increased exposure to credit risk and bad debts. Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our revenue, gross operating margin, cash flows and our ability to make cash distributions to our unitholders. In any of these situations, our revenue, gross operating margin, cash flows and our ability to make cash distributions to our unitholders may be adversely affected. We expect our exposure to concentrated risk of nonpayment or nonperformance to continue as long as we remain substantially dependent on a relatively limited number of customers for a substantial portion of our revenue.

If third-party pipelines, other midstream facilities or purchasers of our products interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather, process or transport do not meet the natural gas and NGL quality requirements of such pipelines or facilities, our gross operating margin, cash flow and our ability to make distributions to our unitholders could be adversely affected.

Our natural gas gathering and transportation pipelines, NGL pipelines and processing and treating facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of such third-party pipelines, processing plants, facilities of purchasers of our products and other midstream facilities is not within our control. These pipelines and facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from natural disasters or other operational hazards. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes we gather, process, treat or transport do not meet the natural gas quality requirements (such as hydrocarbon dew point, temperature

Table of contents

and foreign content including water, sulfur, carbon dioxide and hydrogen sulfide) of such pipelines or facilities, our gross operating margin, cash flow and our ability to make cash distributions to our unitholders could be adversely affected.

Significant portions of our pipeline systems and processing plants have been in service for several decades and we have a limited ownership history with respect to all of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines and processing and treating plants that could have a material adverse effect on our business and operating results.

Significant portions of our pipeline systems and processing plants have been in service for many decades. Our executive management team has a limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems of which our executive management team may be unaware and that may have a material adverse effect on our business and results of operations. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems could adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured, including any interruption of our operations as a result of such accident or event, or if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, our operations and financial results could be adversely affected.

Our operations are subject to all of the risks and hazards inherent in the gathering, compressing, treating, processing and transportation of natural gas and the fractionation and transportation of NGLs, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas, including gas with high levels of hydrogen sulfide, and other hydrocarbons or losses of natural gas as a result of human error, the malfunction of equipment or facilities, which can result in personal injury and loss of life, pollution, damage to equipment and suspension of operations;
- ruptures, fires and explosions; and
- other hazards, including those associated with high-sulfur content, or sour gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in interruptions, curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. In addition, although we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our indemnification rights, for potential environmental liabilities.

We may grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms from Holdings or third parties, our future growth may be affected and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per unit basis.

Our ability to grow is affected, in part, by our ability to make acquisitions that increase our cash generated from operations on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our ability to grow our operations and increase our cash distributions to our unitholders.

Table of contents

If we are unable to make accretive acquisitions from Holdings or third parties whether because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) unable to obtain financing for these acquisitions on economically acceptable terms because our revolving credit facility restricts us from making acquisitions, (iii) outbid by competitors or (iv) for any other reason, then our future growth and ability to increase cash distributions could be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per unit basis.

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

- mistaken assumptions about volumes, revenue and costs, including synergies;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;
- the risk that natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- an inability to integrate successfully the assets or businesses we acquire, particularly given the relatively small size of our management team and their limited history with our assets;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas and business lines; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Incremental projects require access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to finance such projects.

We continuously consider and enter into discussions regarding potential acquisitions or capital expenditures. Any limitations on our access to new capital will impair our ability to execute these projects. If the cost of such capital becomes too expensive, our ability to develop or acquire strategic and accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, including our then current unit price, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

Weak economic conditions and the volatility and disruption in the financial markets could increase the cost of raising money in the debt and equity capital markets substantially while diminishing the availability of funds from those markets. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. These factors may impair our ability to finance future projects.

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing. Weak economic conditions and competition for asset purchases could limit our ability to execute fully on our business strategy.

We may not have access to capital due to deterioration of conditions in the global capital markets, weakening of macroeconomic conditions and negative changes in financial performance.

In general, we rely, in large part, on banks and capital markets to fund our operations, contractual commitments and refinance existing debt. These markets can experience high levels of volatility and access to capital can be constrained for an extended period of time. In addition to conditions in the capital markets, a number of other factors, including our financial performance and any sustained depression of natural gas, NGL and/or crude oil prices (including further extension of the low

Table of contents

energy price environment that began in the second half of 2014), could cause us to incur increased borrowing costs and to have greater difficulty accessing public and private markets for both secured and unsecured debt. If we are unable to secure financing on acceptable terms, our other sources of funds, including available cash, bank facilities and cash flow from operations may not be adequate to fund our operations, contractual commitments and refinance existing debt.

Because our common units are yield-oriented securities, increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates may increase in the future. As a result, interest rates on our future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by our level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Our debt may limit our flexibility to obtain financing and to pursue other business opportunities.

As of December 31, 2016, we had total principal indebtedness of $580.7 million, comprised of $438.8 million related to our term loan and $141.9 million (including outstanding letters of credit) related to our revolving credit facility, which had $3.1 million remaining in unused borrowing capacity. Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and cash distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our parent company's and our own future financial and operating performance, which will be affected by prevailing economic conditions, our Sponsor's ability to fund equity cures, as well as financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

A shortage of skilled labor in the midstream natural gas industry could reduce labor productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The gathering, processing, treating, compression and transportation of natural gas and NGL fractionation and transportation services require skilled laborers in multiple disciplines, such as equipment operators, mechanics and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our General Partner’s employees, our results of operations could be materially and adversely affected.

Restrictions in our revolving credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and the value of our common units.

We are dependent upon the earnings and cash flow generated by our operations in order to meet our debt service obligations and to make cash distributions to our unitholders. The operating and financial restrictions and covenants in our revolving credit facility and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make cash distributions to our unitholders. Our revolving credit facility limits our ability among other things, to:

- incur or guarantee additional debt;

Table of contents

- make distributions on or redeem or repurchase units;
- make certain investments and acquisitions;
- make capital expenditures;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

Our revolving credit facility contains covenants requiring us to maintain certain financial metrics. Our ability to meet those financial metrics and tests can be affected by events beyond our control, and we cannot provide assurance that we will meet those metrics and tests. On December 29, 2016, we entered into the fifth amendment to the Third A&R Revolving Credit Agreement (the “Fifth Amendment”), pursuant to which we received a full waiver for all defaults or events of default arising out of our failure to comply with the financial covenant to maintain a Consolidated Total Leverage Ratio less than 5.00 to 1.00 for all periods ending on or prior to December 31, 2018 (the "Ratio Compliance Date"). See Note 2 to our consolidated financial statements.

The provisions of our revolving credit facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our revolving credit facility could result in a default or an event of default that could enable our lenders, subject to the terms and conditions of our revolving credit facility, to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

For a complete description of long-term debt, see Note 7 to our consolidated financial statements.

If we continue to be unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

We cannot assure you that our business will generate sufficient cash flow from operations to service our outstanding indebtedness, or that future borrowings will be available to us in an amount sufficient to enable us to pay our indebtedness or to fund our other capital needs. If we do not generate sufficient cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring all or a portion of our debt;
- obtaining alternative financing;
- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- revising or delaying our strategic plans.

However, we cannot assure you that we would be able to implement alternative financing plans, if necessary, on commercially reasonable terms or at all, or that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations and capital requirements or that these actions would be permitted under the terms of our various debt instruments.

Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our business, financial condition, results of operations, cash flows and prospects. Any failure to make scheduled payments of interest and principal on our outstanding indebtedness could harm our ability to incur additional indebtedness on acceptable terms. Further, if for any reason we are unable to meet our debt service and repayment obligations,

Table of contents

we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable (which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements), the lenders under our Senior Credit Facilities, as defined in Note 7 to our consolidated financial statements, could terminate their commitments to loan money, and the lenders could foreclose against our assets securing their borrowings and we could be forced into bankruptcy or liquidation. If the amounts outstanding under our Senior Credit Facilities or any of our other indebtedness were to be accelerated, we cannot assure you that the value of our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our natural gas gathering, processing, compression, treating and transportation operations and NGL fractionation services are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection (including, for example, the CAA, the CERCLA, the ESA and the RCRA).

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations or at locations currently or previously owned or operated by us. Numerous governmental authorities, such as the EPA, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions or costly pollution control measures. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. In addition, we may experience a delay in obtaining or be unable to obtain required permits or regulatory authorizations, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbon and other wastes and potential emissions and discharges related to our operations. Joint and several, strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hazardous wastes and other materials on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, changes in environmental laws occur frequently, and any such changes that result in additional permitting obligations or more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. We may not be able to recover all or any of these costs from insurance.

Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the natural gas services we provide.

The EPA has adopted regulations under existing provisions of the CAA that require certain large stationary sources to obtain PSD pre-construction permits and Title V operating permits for GHG emissions, which does not currently apply to our facilities. In addition, in September 2009, the EPA issued a final rule requiring the monitoring and reporting of GHG emissions from certain large GHG emissions sources. Our Gregory, Woodsboro, Bonnie View, Lone Star and El Dorado facilities are or will be required to report under this rule. This reporting rule was expanded in November 2010 to include petroleum and natural gas facilities, including certain natural gas transmission compression facilities, and again in October 2015 to include onshore petroleum and natural gas gathering and boosting activities and natural gas transmission pipelines. We have submitted the reports required under the reporting rule on a timely basis and have adopted procedures for future required reporting. In addition, on June 3, 2016, the EPA issued regulations to control emissions of methane, a GHG, and VOCs from various oil and natural gas operations. Compliance with these rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

While Congress has from time to time considered legislation to reduce emissions of GHGs, the prospect for adoption of significant legislation at the federal level to reduce GHG emissions is perceived to be low at this time. Several states have also implemented programs to reduce and/or monitor GHG emissions. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and

Table of contents

production operators produce, including our current or future customers, which could thereby reduce demand for our midstream services.

In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce GHG emissions. We continue to monitor the international efforts to address climate change. To the extent the United States and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse direct or indirect effect on our business.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. Due to their location, our operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems and our insurance may not cover all associated losses. We are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on our business.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

A portion of our customers' natural gas production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing has become the subject of opposition, additional private and government studies and increased federal, state and local regulation. For example, from time to time, Congress has considered legislation to amend the Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act's Underground Injection Control Program and to require disclosure of chemicals used in the hydraulic fracturing process. The EPA has adopted and proposed new regulations under the CAA requiring, among other things, the use of "reduced emission completion" technology for certain hydraulic fracturing operations and related equipment, and has solicited public comment on a possible federal reporting requirement for fluids used in hydraulic fracturing pursuant to the Toxic Substances Control Act. Compliance with such laws and regulations could result in additional costs, including increased capital expenditures and operating costs, for us and our customers, which may adversely impact our cash flows and results of operations. Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. We cannot predict whether any other legislation will be enacted and if so, what its provisions would be. Additional levels of regulation and permits required through the adoption of new laws and regulations at the federal or state level could lead to delays, increased operating costs and prohibitions for producers who drill near our pipelines. This could reduce the volumes of natural gas available to move through our gathering systems which could materially and adversely affect our revenue and results of operations.

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

One of the ways we intend to grow our business is through organic growth projects. The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political, legal and economic uncertainties that are beyond our control. Such expansion projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. Moreover, our revenue may not increase immediately upon the expenditure of funds on a particular project.

For instance, if we expand a pipeline, the construction may occur over an extended period of time, yet we will not receive any material increases in revenue until the project is completed and placed into service. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize or only materializes over a period materially longer than expected. Since we are not engaged in the exploration for and development of natural gas and crude oil reserves, we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production.

Table of contents

As a result, new facilities may not attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way or environmental authorizations. We may be unable to obtain such rights-of-way or authorizations and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or authorizations or to renew existing rights-of-way or authorizations. If the cost of renewing or obtaining new rights-of-way or authorizations increases materially, our cash flows could be adversely affected.

A change in the jurisdictional characterization or regulation of our assets or a change in regulatory laws and regulations or the implementation of existing laws and regulations could result in increased regulation of our assets which could materially and adversely affect our financial condition, results of operations and cash flows.

Intrastate transportation facilities that do not provide interstate transmission services, and gathering facilities, are exempt from the jurisdiction of FERC under the NGA. Although FERC has not made any formal determinations with respect to any of our facilities, we believe that our intrastate natural gas pipelines and related facilities that are not engaged in providing interstate transmission services are engaged in exempt gathering and intrastate transportation and, therefore, are not subject to FERC jurisdiction. We also believe that our natural gas gathering pipelines meet the traditional tests that FERC has used to determine if a pipeline is a gathering pipeline and is therefore not subject to FERC’s jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and, over time, FERC’s policy for determining which facilities it regulates has changed. In addition, the distinction between FERC-regulated transmission facilities, on the one hand, and intrastate transportation and gathering facilities, on the other, is a fact-based determination made by FERC on a case-by-case basis. If FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the Natural Gas Policy Act of 1978 (“NGPA”). Such regulation could decrease revenue, increase operating costs and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by FERC.

Some of our intrastate pipelines provide interstate transportation service regulated under Section 311 of the NGPA. Rates charged under Section 311 must be “fair and equitable,” and amounts collected in excess of fair and equitable rates are subject to refund with interest. Accordingly, such regulation may prevent us from recovering our full cost of service allocable to such interstate transportation service. In addition, some of our intrastate pipelines may be subject to complaint-based state regulation with respect to our rates and terms and conditions of service, which may prevent us from recovering some of our costs of providing service. The inability to recover our full costs due to FERC and state regulatory oversight and compliance could materially and adversely affect our revenues.

Moreover, FERC regulation affects our gathering, transportation and compression business generally. FERC’s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, market transparency, market manipulation, ratemaking, capacity release, segmentation and market center promotion, directly and indirectly affect our gathering and pipeline transportation business. In addition, the classification and regulation of our gathering and intrastate transportation facilities also are subject to change based on future determinations by FERC, the courts or Congress.

State regulation of gathering facilities generally includes safety and environmental regulation and complaint-based ratable take requirements and rate regulation. State and local regulation may cause us to incur additional costs or limit our operations, and may prevent us from choosing the customers to which we provide service. Due to increased gathering activity, among other considerations, natural gas gathering is beginning to receive greater legislative and regulatory scrutiny which could result in new regulations or enhanced enforcement of existing laws and regulations. Increased regulation of natural gas gathering could adversely affect our financial condition, results of operations, cash flows and our ability to make cash distributions to our unitholders.

We may incur greater than anticipated costs and liabilities as a result of pipeline safety regulation, including integrity management program testing and related repairs.

The DOT, through PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could harm “high consequence areas” unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. High consequence areas include high

33

Table of contents

population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways. The regulations require operators, including us, to:

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

In addition, many states, including the states in which we operate, have adopted regulations similar to existing DOT regulations for intrastate pipelines. Although many of our pipeline facilities fall within a class that is currently not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with our non-exempt pipelines, particularly in South Texas. We have incurred costs of approximately $0.8 million and $1.1 million during the years ended December 31, 2016 and 2015, respectively, in order to complete the testing required by existing DOT regulations and their state counterparts. This expenditure included all costs associated with repairs, remediations, preventative and mitigating actions related to the 2016 and 2015 testing programs.

Should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. Additionally, pipeline safety reforms, including new requirements, enhanced penalties and changes in the administration and enforcement of safety laws have been implemented in recent years and the consideration of additional reforms is ongoing. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service.

The implementation of statutory and regulatory requirements for derivative transactions could increase the costs and have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was enacted in 2010 and amended the Commodity Exchange Act. This law regulates derivative and commodity transactions, including crude oil and gas hedging transactions used in our risk management activities. The Dodd-Frank Act requires the Commodity Futures Trading Commission (“CFTC”) and other regulators to promulgate rules and regulations implementing the new legislation. While many of the regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

In its rulemaking under the Dodd-Frank Act, the CFTC will likely finalize regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, although certain bona fide hedging transactions would be exempt from these position limits provided that various conditions are satisfied. Once finalized, the position limits rule and its companion rule on aggregation may have an impact on our ability to hedge our exposure to certain enumerated commodities.

The Dodd-Frank Act provisions are also intended to change fundamentally the way swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which many swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. To date, several categories of interest rate and index credit default swaps have been designated by the CFTC as mandatorily clearable swaps. These swaps may also be required to be traded on registered swap execution facilities or exchanges. Both the clearing and the trading requirements are likely to increase significantly transaction costs of entering into swaps (e.g., by entering into agreements with and paying commission to brokerage and clearing intermediaries). Even if we chose to rely on the end-user exception from the clearing and trading requirements, we would be required to take certain steps to qualify for the end-user exception. As the CFTC further designates swap contracts as required to be cleared and traded on a trading facility, the utility of the end-user exception will become even more important. Our ability to rely on the end-user exception may change the profitability of our trades or the efficiency of our hedging.

The Dodd-Frank Act and any new regulations could, among other things, significantly increase the cost of entering into derivative and commodity contracts (including from swap record-keeping and reporting requirements), materially alter the terms of derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, require greater collateral support for derivative contracts and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act

Table of contents

and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Any of these consequences could have a material adverse effect on our financial condition, results of operations and cash available for distribution to unitholders.
Because the CFTC is still in the process of interpreting its regulations, it is possible that some of the derivative and commodity contracts used in our business may be treated differently in the future. For example, the CFTC may further revise its definitions for spots, forwards, forwards with volumetric optionality, trade options, full requirements contracts and certain other contracts that may combine the elements of physical commodity trades and cash settlement, netting and book-outs. If these contracts were classified as swaps, the costs of entering into these contracts will likely increase.

Finally, under the Dodd-Frank Act, the CFTC is also directed generally to prevent price manipulation and fraud in physical commodities markets traded in interstate commerce, including physical energy and other commodities, as well as financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation, anti-fraud and disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets. Accordingly, the CFTC and the self-regulatory organizations (“SROs”), such as commodity futures exchanges, are continuing to develop their respective enforcement authorities and compliance priorities under the Dodd-Frank Act. Given the novelty of the regulations under the Dodd-Frank Act, it is difficult to predict how these new enforcement priorities of the CFTC and the SROs will impact our business. Should we violate the Commodity Exchange Act, as amended, the regulations promulgated by the CFTC, and any rules adopted by the SROs thereunder, we could be subject to CFTC enforcement action and material penalties and sanctions.

Cyber-attacks, acts of terrorism or other disruptions could adversely impact our results of operations and our ability to make cash distributions to unitholders.
We are subject to cyber security risks related to breaches in the systems and technology that we use (i) to manage our operations and other business processes and (ii) to protect sensitive information maintained in the normal course of our businesses. The gathering, processing and transportation of natural gas from our gathering, processing and pipeline facilities are dependent on communications among our facilities and with third-party systems that may be delivering natural gas into or receiving natural gas and other products from our facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt our ability to deliver natural gas and control these assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt our operations and critical business functions, adversely affect our reputation and subject us to possible legal claims and liability, any of which could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. In addition, our natural gas pipeline systems may be targets of terrorist activities that could disrupt our ability to conduct our business and have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.
Our General Partner's ability to operate our business effectively could be impaired if we fail to attract and retain key management and personnel.
Our ability to operate our business and implement our strategies will depend on our General Partner's continued ability to attract and retain highly skilled management personnel with midstream natural gas industry experience. Competition for these persons in the midstream natural gas industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ senior executives and key personnel or attract and retain qualified personnel in the future. Our failure to retain or attract senior executives and key personnel, in addition to the significant changes to our General Partner's management in 2016, could have a material adverse effect on our ability to operate our business effectively.

We do not have employees. We rely solely on officers and employees of our General Partner to operate and manage our business.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results timely and accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

We are subject to the public reporting requirements of the Exchange Act, including the rules thereunder that require our management to certify financial and other information in our quarterly and annual reports and provide an annual management

Table of contents

report on the effectiveness of our internal control over financial reporting. Effective internal controls are necessary for us to provide reliable and timely financial reports, prevent fraud and to operate successfully as a publicly traded partnership. We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"), but our internal accounting controls may not meet all standards applicable to companies with publicly traded securities. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley, which we refer to as Section 404.

Given the difficulties inherent in the design and operation of internal controls over financial reporting, in addition to our limited accounting personnel and management resources, we can provide no assurance as to our or our independent registered public accounting firm's future conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Any failure to implement and maintain effective internal controls over financial reporting will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

We are required to disclose changes made in our internal control and procedures on a quarterly basis and make an annual assessment of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act. As a smaller reporting company, as defined in Rule 12b-2 of the Securities Exchange Act of 1934, and an emerging growth company under the JOBS Act, our independent registered public accounting firm is not required to attest annually to the effectiveness of our internal control over financial reporting.

The amount of cash we have available for distribution to holders of our common units, subordinated units and Class B Convertible Units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Risks Inherent in an Investment in Us

Holdings indirectly owns and controls our General Partner, which has sole responsibility for conducting our business and managing our operations as well as has limited duties to us and our unitholders. Holdings, its general partner and owners, and our General Partner have conflicts of interest with us and they may favor their own interests to the detriment of us and our other unitholders.

Holdings controls our General Partner and has the authority to appoint all of the officers and directors of our General Partner. Pursuant to the organizational documents of the general partner of Holdings, two directors (one of whom must be independent) on our board of directors will be appointed by each of EIG, Tailwater and the group of lenders that received membership interests in Holdings in connection with Holdings' Chapter 11 reorganization. David W. Biegler served as the chairman of the board of our General Partner through January 6, 2017, at which time Bruce A. Williamson was appointed chairman of the board of our General Partner. Although our General Partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our General Partner also have a duty to manage our General Partner in a manner that is beneficial to its ultimate owner, Holdings. Conflicts of interest may arise between Holdings and our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of Holdings over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our Third Amended and Restated Agreement of Limited Partnership ("Partnership Agreement") nor any other agreement requires Holdings to pursue a business strategy that favors us.
- Our General Partner is allowed to take into account the interests of parties other than us, such as Holdings, in resolving conflicts of interest.
-

Our Partnership Agreement replaces the fiduciary duties that would otherwise be owed by our General Partner to us and our unitholders with contractual standards governing its duties to us and our unitholders, limits our General Partner’s liabilities, and also restricts the rights of our unitholders with respect to actions that, without the limitations, might constitute breaches of fiduciary duty.

Table of contents

- Except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval.
- Our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.
- Our General Partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or a growth capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our General Partner and the ability of the subordinated units to convert to common units.
- Our General Partner determines which costs incurred by it are reimbursable by us.
- Our General Partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- Our Partnership Agreement permits us to classify up to $35.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our General Partner in respect of the general partner interest or the incentive distribution rights.
- Our Partnership Agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our General Partner has limited its liability regarding our contractual and other obligations.
- Our General Partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.
- Our General Partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our General Partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our General Partner’s incentive distribution rights without the approval of the conflicts committee of the board of directors of our General Partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Each of Tailwater and EIG is not limited in its ability to compete with us and is not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

Tailwater and EIG are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. Tailwater and EIG may each acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities. Moreover, while Tailwater and EIG may offer us the opportunity to buy additional assets from them, neither of them are under a contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed. Tailwater and EIG are each private equity firms with significantly greater resources than us with experience making investments in midstream energy businesses. Tailwater and EIG may each compete with us for investment opportunities and may own interests in entities that compete with us.

Pursuant to the terms of our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our General Partner, its executive officers, or any of its affiliates, including Tailwater and EIG. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our General Partner and result in less than favorable treatment of us and our unitholders.

37

Table of contents

The market price of our common units may fluctuate significantly, and you could lose all or part of your investment.
There were 22,010,016 publicly traded common units as of December 31, 2016. In addition, Holdings owned 26,492,074 common units, 12,213,713 subordinated units and 17,105,875 Class B Convertible Units as of December 31, 2016. You may not be able to resell your common units at or above your acquisition price. Additionally, a lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.
The market price of our common units may decline and be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions (or any suspension thereof);
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these "Risk Factors."

Our General Partner has limited its liability regarding our obligations.
Our General Partner has limited its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our General Partner or its assets. Our General Partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our General Partner. Our Partnership Agreement provides that any action taken by our General Partner to limit its liability is not a breach of our General Partner’s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our General Partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.
Our Partnership Agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.
If we reinstate our distributions, we expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and growth capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.
In addition, if we reinstate our distributions and we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or growth capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our Partnership Agreement or our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.
While our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including provisions requiring us to make cash distributions contained therein, may be amended.
While our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our Partnership Agreement generally may not be amended during the subordination period without the approval of a majority our public common unitholders. However, our Partnership Agreement can be amended with the consent of our General Partner and the approval of a majority of the outstanding common units (including common units held by affiliates of our General Partner) after the subordination period

38

Table of contents

has ended. As of March 1, 2017, Holdings, the 100% owner of our General Partner, owned, indirectly, 54.6% of the outstanding common units, 100% of our outstanding subordinated units and 100% of our outstanding Class B Convertible Units.

Reimbursements due to our General Partner and its affiliates for services provided to us or on our behalf reduce cash available for distribution to our common unitholders. The amount and timing of such reimbursements will be determined by our General Partner.

We reimburse our General Partner and its affiliates, including Holdings, for expenses they incur and payments they make on our behalf. Under our Partnership Agreement, we reimburse our General Partner and its affiliates for certain expenses incurred on our behalf including, among other items, compensation expense for all employees required to manage and operate our business. Our Partnership Agreement provides that our General Partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our General Partner and its affiliates reduce the amount of available cash to pay cash distributions to our common unitholders.

Holdings' Chapter 11 proceeding may adversely affect us.

On March 28, 2016, Holdings and certain of its subsidiaries (other than us, our General Partner and our subsidiaries) filed a pre-packaged plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code in the Southern District of Texas to restructure its debt obligations and strengthen its balance sheet. On April 11, 2016, the bankruptcy court confirmed Holdings’ Chapter 11 reorganization and on April 13, 2016, Holdings and its subsidiaries emerged from its reorganization. Holdings’ Chapter 11 proceeding may affect adversely the way we and our counterparty affiliates are perceived by investors, financial markets, contract counterparties, customers, suppliers and regulatory authorities, which could adversely affect our operations and financial performance. If we fail to attract and retain customers, as well as other contract or trading counterparties as a result of Holdings’ Chapter 11 reorganization, it could adversely affect our financial performance and results of operations.

Our Partnership Agreement replaces our General Partner’s fiduciary duties to holders of our common and subordinated units with contractual standards governing its duties.

Our Partnership Agreement contains provisions that eliminate the fiduciary duties to which our General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our Partnership Agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the partners where the language in the Partnership Agreement does not provide for a clear course of action. This entitles our General Partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our General Partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our General Partner;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights or any units it owns to a third party; and
- whether or not to consent to any merger or consolidation of the Partnership or amendment to the Partnership Agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

Table of contents

Our Partnership Agreement restricts the rights of holders of our common and subordinated units with respect to actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that restrict the rights of unitholders with respect to actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our Partnership Agreement provides that:

- whenever our General Partner makes a determination or takes, or declines to take, any other action in its capacity as our General Partner, our General Partner is required to make such determination, or take or decline to take such other action, in good faith, meaning it subjectively believed that the decision was in the best interest of us and our unitholders, and except as specifically provided by our Partnership Agreement, will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as such decisions are made in good faith;
- our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors, as the case may be, acted in bad faith or engaged in intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our General Partner will not be in breach of its obligations under the Partnership Agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:

approved by the conflicts committee of the board of directors of our General Partner, although our General Partner is not obligated to seek such approval;

approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates, although our General Partner is not obligated to seek such approval;

determined by the board of directors of our General Partner to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

determined by the board of directors of our General Partner to be fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our General Partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our General Partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the final two subclauses above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our Partnership Agreement provides that our conflicts committee may be comprised of one or more independent directors, though we currently have a three member committee of independent directors. If we establish a conflicts committee with only one independent director, your interests may not be as well served as if we had a conflicts committee comprised of at least two independent directors. A single-member conflicts committee would not have the benefit of discussion with, and input from, other independent directors.

Our General Partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our General Partner's incentive distribution rights without the approval of the conflicts committee of our General Partner's board or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Our General Partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election by our General Partner, the minimum quarterly distribution will be reset to an amount equal to the

average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.
We anticipate that our General Partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our General Partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our General Partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our General Partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for our General Partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our General Partner in connection with resetting the target distribution levels related to our General Partner's incentive distribution rights.
Holders of our common units have limited voting rights and are not entitled to elect our General Partner or its directors.
Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The board of directors of our General Partner will be chosen by Holdings. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.
Even if holders of our common units are dissatisfied, they cannot currently remove our General Partner without its consent.
Our unitholders are currently unable to remove our General Partner without its consent because our General Partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our General Partner. As of March 1, 2017, Holdings indirectly owns an approximate 71.8% limited partner interest in us. Also, if our General Partner is removed without cause during the subordination period and units held by our General Partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our General Partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our General Partner liable for actual fraud or willful misconduct in its capacity as our General Partner. Cause does not include most cases of charges of poor management of the business, so the removal of our General Partner because of the unitholder's dissatisfaction with our General Partner's performance in managing us will most likely result in the termination of the subordination period and the conversion of all subordinated units to common units.
Our Partnership Agreement restricts the voting rights of unitholders owning 20% or more of our common units.
Unitholders' voting rights are further restricted by a provision of our Partnership Agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, cannot vote on any matter.

Our General Partner interest or the control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its General Partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our Partnership Agreement does not restrict the ability of Holdings to transfer all or a portion of its ownership interest in our General Partner to a third party. The new owner of our

Table of contents

General Partner would then be in a position to replace the board of directors and officers of our General Partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers. This effectively permits a "change of control" without the vote or consent of the unitholders.

We may issue additional units without your approval, which would dilute your existing ownership interests. For example, in connection with the Fifth Amendment, our parent made a $17 million contribution to us to pay down the outstanding balance under the Third A&R Revolving Credit Agreement and for general corporate purposes, in exchange for 11,486,486 common units, which diluted the common unitholders.

Our Partnership Agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Holdings may sell our units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of March 1, 2017, Holdings held an aggregate of 26,492,074 common units, 12,213,713 subordinated units and 17,405,250 Class B Convertible Units. All of the subordinated units will convert into common units at the end of the subordination period. The Class B Convertible Units will convert into common units when we make a distribution for any quarter to holders of common units equal to or more than $0.44 per common unit, when we generate class B distributable cash flow, and paid, the declared distribution on all outstanding units for the two prior quarters, and when we forecast paying a distribution equal to or more than $0.44 per outstanding unit from forecasted class B distributable cash flow on all outstanding units for the next two quarters. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

If at any time our General Partner and its affiliates own more than 80% of the common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our Partnership Agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of March 1, 2017, Holdings owned approximately 54.6% of our 48,516,567 outstanding common units. At the end of the subordination period and following the conversion of the Class B Convertible Units, assuming no additional issuances of common units (other than upon the conversion of the subordinated units and the Class B Convertible Units), Holdings will own approximately 71.8% of our outstanding common units.

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

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

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other unitholders to remove or replace our General Partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitute "control" of our business.

Table of contents

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to us that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the Partnership Agreement. Neither liabilities to partners on account of our interest nor liabilities that are non-recourse to us are counted for purposes of determining whether a distribution is permitted.

The TexStar Rich Gas System and the Valley Wells System may not be as beneficial to us as we expect.

As a result of our acquisition of the TexStar Rich Gas System and the drop-down acquisition of the Valley Wells System, we are subject to additional risks, in particular the risk we fail to realize the expected profitability, growth or accretion from the transaction. These acquisitions involve additional potential risks, including:

- failure to operate the current facilities and assets within operational expectations;
- construction cost overruns and delays resulting from numerous factors, many of which may be out of our control;
- the temporary diversion of management’s attention from our existing business;
- an increase in our interest expense and financial leverage resulting from additional debt incurred to finance the TexStar Rich Gas System, which may offset the expected accretion from such acquisition;
- operations regarding the joint venture arrangements;
- the ability to add additional rich gas volumes onto our system;
- failure or delay of a project owned by a subsidiary of Holdings that is expected to bring additional gas volumes onto the TexStar Rich Gas System;
- title issues or liabilities or accidents;
- the incurrence of unanticipated liabilities and costs for which indemnification is unavailable or inadequate;
- environmental or regulatory compliance matters or liabilities.

If these risks or other unanticipated liabilities were to materialize, the desired benefits of the acquisitions of the TexStar Rich Gas System or the Valley Wells System may not be fully realized, and our future financial performance and results of operations could be negatively impacted.

We may be unable to grow through the acquisitions of current or future assets of Holdings, which could limit our ability to maintain or increase distributions to our unitholders.

Holdings is under no obligation to offer us the opportunity to purchase its current or future assets, and the board of directors of its general partner owes fiduciary duties to its members, and not our unitholders, in making any decision to offer us this opportunity. Likewise, we are not required to purchase any additional assets from Holdings.

The consummation of any such purchases will depend upon, among other things, our ability to reach an agreement with Holdings regarding the terms of such purchases (which will require the resolution of the conflict of interest pursuant to our Partnership Agreement) and our ability to finance such purchases on acceptable terms. Additionally, Holdings may be limited in its ability to consummate sales of additional portions of such business to us by the terms of its existing or future credit facilities. Furthermore, our revolving credit facility includes covenants that may limit our ability to finance acquisitions. If a sale by Holdings of any additional assets would be restricted or prohibited by such covenants, we or Holdings may be required to seek waivers of such provisions or refinance those debt instruments in order to consummate a sale, neither of which may be accomplished timely, if at all. If we are unable to grow through additional acquisitions of Holdings's current or future assets, our ability to maintain or increase distributions to our unitholders may be limited.

Risks Related to our Common Units

We were not in compliance with the New York Stock Exchange's requirements for continued listing for a portion of 2016, and therefore could have been delisted, which would have decreased the common unit price and would have had a material adverse effect on our liquidity and our business. We may not be able to continue to comply with the New York Stock Exchange's requirements for continued listing.

On February 18, 2016, we received a letter from the New York Stock Exchange ("NYSE") notifying us that we no longer met the NYSE's requirements for continued listing under Section 802.01C of the NYSE Listed Company Manual because the average closing price of our common units did not equal or exceed $1.00 per unit over a period of 30 consecutive trading days prior to the date of the notification letter. We had six months following receipt of the NYSE's notice to regain compliance with the minimum unit price criteria, which we complied with on May 3, 2016. However, if at any time our common unit price drops to the point where the NYSE considers the price to be "abnormally low," the NYSE has the discretion to begin delisting proceedings immediately. While there is no formal definition of "abnormally low" in the NYSE rules, the NYSE recently has delisted the common stock of issuers when it trades below $0.16 per share. In addition, the NYSE will promptly initiate suspension and delisting procedures if the NYSE determines that we have an average global market capitalization over a consecutive 30 trading-day period of less than $15.0 million.

No assurances can be made that we will in fact be able to continue to comply and that our common units will remain listed on the NYSE. If our common units are delisted from the NYSE, such delisting could negatively impact the market price of our common units, reduce the number of investors willing to hold or acquire our common units, and limit our ability to issue additional securities or obtain additional financing in the future, and might negatively impact our reputation and, as a consequence, our business.

The price of our common units may be adversely affected by the future issuance and sale of additional common units, or by our announcement that such issuances and sales may occur.

We cannot predict the size of future issuances or sales of our common units, including in connection with future acquisitions or capital raising activities, or the effect, if any, that such issuances or sales may have on the market price of our common units. The issuance and sale of substantial amounts of common units or the announcement that such issuances and sales may occur, could adversely affect the market price of our common units.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service (IRS) were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, or if we were otherwise subjected to a material amount of additional entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce our cash available for distribution to our unitholders. Therefore, if we were treated as a corporation for federal income tax purposes or otherwise subjected to a material amount of entity-level taxation, there would be material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Table of contents

Our Partnership Agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of the U.S. Congress and the President of the United States periodically have considered substantive changes to existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships.

On January 24, 2017, the U.S. Treasury Department and the IRS published final regulations regarding qualifying income under Section 7704(d)(1)(E) of the Code. We do not believe these regulations adversely affect our status as a partnership for federal income tax purposes.

Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to satisfy the requirements of the exception pursuant to which we are treated as a partnership for federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

Unitholders' share of our income is taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder is treated as a partner to whom we allocate taxable income that could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income is taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income even if the unitholder receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

We may engage in transactions to de-lever the Partnership and manage our liquidity that may result in income and gain to our unitholders. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences of potential COD income or other transactions that may result in income and gain to unitholders.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take or may take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all the positions we take or may take. A court may not agree with some or all of the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our cash available for distribution. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his or her return. Any audit of a unitholder's return could result in adjustments not related to our returns, as well as those related to our returns.

45

Table of contents

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as a result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

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

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

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

If our unitholders sell common units, they will recognize gain or loss for federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the common units they sell will, in effect, become taxable income to them if they sell such common units at a price greater than their tax basis in those common units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized on any sale of their common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if our unitholders sell their common units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investments in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, is unrelated business taxable income and is taxable to them. Distributions to non-U.S. persons are reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons are required to file federal income tax returns and pay tax on their share of our taxable income.

We treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from their sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders’ tax returns.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge aspects of our proration method, and, if successful, we would be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

Table of contents

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of Treasury and the IRS recently issued Treasury regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this method, we could be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose common units are loaned to a “short seller” to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income.

We have adopted certain valuation methodologies in determining a unitholder's allocation of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of the common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, in certain circumstances, including when we issue additional units, we must determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

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

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections, including a new election under Internal Revenue Code Section 754, and we could be subject to penalties if we are unable to determine that a termination occurred.

The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, we will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

Table of contents

As a result of investing in our common units, our unitholders may be subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.
In addition to federal income taxes, our unitholders are likely to be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently conduct business in Alabama, Mississippi and Texas. Some of these states currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is our unitholders' responsibility to file all federal, state and local tax returns.

Compliance with and changes in tax laws could adversely affect our performance.
We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments
None.
Item 2. Properties
Our real property falls into two categories:

1. parcels that we own in fee title; and
2. parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations.

Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors.
We are not aware of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses. A description of our properties is included in Part I, Item 1 of this report and incorporated herein by reference.

Item 3. Legal Proceedings
Please refer to Note 8 of our consolidated financial statements included in this Form 10-K for a description of our legal proceedings.
Item 4. Mine Safety Disclosures
Not applicable.

Table of contents

Item 5. Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities

Market Information

Our common units are listed on the NYSE under the symbol "SXE." The table below sets forth the high and low sales prices of our common units and the per unit distributions declared since January 1, 2015. The last reported sale price of our common units on the NYSE on March 1, 2017 was $3.42. Distributions are recorded when paid.

	Unit Prices		Distributions	
Period	High	Low	per common unit	Payment date
Fourth Quarter 2016	$1.65	$1.10	(a)	(a)
Third Quarter 2016	2.10	1.32	(a)	(a)
Second Quarter 2016	3.65	1.02	(a)	(a)
First Quarter 2016	3.73	0.38	(a)	(a)
Fourth Quarter 2015	6.60	2.28	(a)	(a)
Third Quarter 2015	12.81	4.77	0.40	November 13, 2015
Second Quarter 2015	16.20	10.88	0.40	August 14, 2015
First Quarter 2015	16.35	11.76	0.40	May 14, 2015

(a) We did not pay quarterly distributions with respect to these quarters.

As of March 1, 2017, there were 3 holders of record, approximately 5,400 beneficial owners of our common units and 48,516,567 common units outstanding. As of March 1, 2017, we have issued 12,213,713 subordinated units, 17,405,250 Class B Convertible Units and 1,594,602 general partner units, for which there is no established trading market.

Distribution of Available Cash

General. 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.

Definition of Available Cash. Available cash generally means, for any quarter, all cash on hand at the end of that quarter:

- less the amount of cash reserves established by our General Partner at the date of determination of available cash for that quarter to:
- provide for the proper conduct of our business (including reserves for our future capital expenditures and anticipated future credit needs);
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our General Partner for any one or more of the next four quarters (provided that our General Partner may not establish cash reserves for distributions unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);
- plus, if our General Partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Working capital borrowings are generally borrowings that are made under a credit facility or another arrangement that are used solely for working capital purposes or to pay distributions to unitholders, and are intended to be repaid within 12 months.

Minimum Quarterly Distribution. Commencing with the fourth quarter of 2012, we made quarterly distributions to the holders of our common units and, until the third quarter of 2014, to the holders of our subordinated units of $0.40 per unit, or $1.60 on an annualized basis (with the first such distribution being prorated). There is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our General Partner, taking into consideration the terms of our Partnership Agreement and requirements under our Credit Facility (as defined

Table of contents

below). Beginning with the third quarter of 2014, until such time that we have a ratio of distributable cash flow divided by cash distributions ("Distributable Cash Flow Ratio") of at least 1.0, Holdings, the indirect holder of our 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 First Amendment and the Fifth Amendment (defined in Note 7 to the consolidated financial statements) imposed additional restrictions on our ability to declare and pay quarterly cash distributions with respect to our subordinated units.

Distribution Suspension

The board of directors of our General Partner suspended paying a quarterly distribution with respect to the fourth quarter of 2015 and every quarter of 2016 to reserve any excess cash for the operation of our business. The board of directors of our General Partner and our management believe this suspension to be in the best interest of our unitholders and will continue to evaluate our ability to reinstate the distribution in future periods. Additionally, we are restricted under the fifth amendment to the Third A&R Revolving Credit Agreement on paying a distribution until our Consolidated Total Leverage Ratio is below 5.0. See Notes 2 and 4 to our consolidated financial statements.

General Partner Interest and Incentive Distribution Rights

Our General Partner currently is entitled to 2.0% of all distributions that we make prior to our liquidation. Our General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current General Partner interest. Our General Partner's initial 2.0% interest in our distributions will be reduced if we issue additional limited partner units in the future and our General Partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

Our General Partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus in excess of $0.46 per unit per quarter. The maximum distribution of 50% includes distributions paid to our General Partner on its 2.0% general partner interest and assumes that our General Partner maintains its general partner interest at 2.0%. The maximum distribution of 50% does not include any distributions that our General Partner may receive on any limited partner units that it owns.

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our General Partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our General Partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit Target Amount." The percentage interests shown for our unitholders and our General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our General Partner include its 2.0% general partner interest and assume that our General Partner has contributed any additional capital necessary to maintain its 2.0% general partner interest, our General Partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

		Marginal Percentage Interest In Distributions	
	Total Quarterly Distribution Per Unit Target Amount	Unitholders	General Partner
Minimum quarterly distribution	$0.40	98 %	2 %
First target distribution	$0.40 up to $0.46	98 %	2 %
Second target distribution		85 %	15 %

	above $0.46 up to $0.50		
Third target distribution	above $0.50 up to $0.60	75 %	25 %
Thereafter	above $0.60	50 %	50 %

Securities Authorized for Issuance Under Equity Compensation Plan

See discussion in Part III, Item 12 of this report entitled “Securities Authorized for Issuance Under Equity Compensation Plan.”

Table of contents

Item 6. Selected Financial Data

As a smaller reporting company, we are not required to provide the information required by Item 6.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is a discussion of our historical consolidated financial condition and results of operations that is intended to help the reader understand our business, results of operations and financial condition. It should be read in conjunction with other sections of this report, including our historical consolidated financial statements and accompanying notes thereto included in Part II, Item 8 of this report.

Overview and How We Evaluate our 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." 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 two gas processing plants, one fractionation facility and gathering and transportation pipelines.

Southcross Holdings LP, a Delaware limited partnership (“Holdings”), indirectly owns 100% of Southcross Energy Partners GP, LLC, a Delaware limited liability company, our general partner (“General Partner”) (and therefore controls us), all of our subordinated and Class B convertible units (the "Class B Convertible Units") and 54.6% of our common units. Our General Partner owns an approximate 2.0% interest in us and all of our incentive distribution rights.

Following the emergence of Holdings from its Chapter 11 reorganization proceeding on April 13, 2016 (as discussed below), EIG Global Energy Partners, LLC (“EIG”) and Tailwater Capital LLC (“Tailwater”) (collectively, the “Sponsors”) each indirectly own approximately one-third of Holdings, and a group of consolidated lenders under Holdings' term loan (the "Lenders") own the remaining one-third of Holdings.

Recent Developments

Amendments to Third A&R Revolving Credit Agreement

On July 25, 2016, we determined Holdings’ cash contribution to us for the first quarter 2016 equity cure had not been transferred to us timely, as required under the Third Amended and Restated Revolving Credit Agreement with Wells Fargo, N.A., UBS Securities LLC, Barclays Bank PLC and a syndicate of lenders (the "Third A&R Revolving Credit Agreement"), as amended in May 2015, due to an administrative oversight, which resulted in a default. On July 26, 2016, Holdings fully funded the first quarter 2016 equity cure. On August 4, 2016, we entered into a limited waiver and second amendment to the Third A&R Revolving Credit Agreement whereby the lenders waived any default or right to exercise any remedy as a result of this technical event of default to fund timely the first quarter 2016 equity cure.

On November 8, 2016, we entered into a limited waiver and third amendment to the Third A&R Revolving Credit Agreement (the “Third Amendment”), which stipulated, among other things, that (i) the equity cure funding deadline for the quarter ended September 30, 2016 (“Q3 2016 Equity Cure”) was extended from November 23, 2016 to December 16, 2016, and (ii) limited the total revolving credit exposure. On December 9, 2016, we entered into the waiver and fourth amendment to the Third A&R Revolving Credit Agreement (the "Fourth Amendment"), which stipulated, among other things, that (i) the deadline for funding the Q3 2016 Equity Cure was further extended from December 16, 2016 to January 12, 2017, and (ii) the Third A&R Revolving Credit Agreement was amended to require that any account into which we deposit funds, securities or commodities be subject to a lien and a control agreement for the benefit of the secured parties under the Third A&R Revolving Credit Agreement.

On December 29, 2016, we entered into the waiver and fifth amendment to the Third A&R Revolving Credit Agreement (the “Fifth Amendment”), pursuant to which we received a full waiver for all defaults or events of default arising out of our failure to comply with the financial covenant to maintain a Consolidated Total Leverage Ratio less than 5.00 to 1.00 for the quarter ended September 30, 2016.

Additionally, pursuant to the Fifth Amendment, (i) total aggregate commitments under the Third A&R Revolving Credit Agreement were reduced from $200 million to $145 million and the sublimit for letters of credit also was reduced from $75 million to $50 million (total aggregate commitments will be further periodically reduced through December 31, 2018); (ii) the Consolidated Total Leverage Ratio and Consolidated Senior Secured Leverage Ratio (each of which is defined in the Fifth Amendment) financial covenants were suspended until the quarter ended March 31, 2019; (iii) the Consolidated Interest Coverage Ratio (as defined in the Fifth Amendment) financial covenant requirement was reduced from 2.50 to 1.00 to 1.50 to 1.00 for all periods ending on or prior to December 31, 2018 (the "Ratio Compliance Date"). Prior to the Ratio Compliance Date, we are required to maintain minimum levels of Consolidated EBITDA on a quarterly basis and are subject to certain covenants and restrictions related to liquidity and capital expenditures. See Note 7 to our consolidated financial statements.

In connection with the execution of the Fifth Amendment, on December 29, 2016, the Partnership entered into (i) an Investment Agreement (the "Investment Agreement") with Holdings and Wells Fargo Bank, N.A., (ii) a Backstop Commitment Letter (the "Backstop Agreement") with Holdings, Wells Fargo Bank, N.A. and the Sponsors and (iii) a First Amendment to Equity Cure Contribution Agreement (the "Equity Cure Contribution Amendment") with Holdings. Pursuant to the Equity Cure Contribution Amendment, on December 29, 2016, Holdings contributed $17.0 million to us in exchange for 11,486,486 common units. The proceeds of the $17.0 million contribution were used to pay down the outstanding balance under the Third A&R Revolving Credit Agreement and for general corporate purposes. In addition, pursuant to entering into the Investment Agreement, the previous Equity Cure Contribution Agreement with Holdings terminated and Holdings agreed to contribute $15.0 million to us (the "Committed Amount") upon the earlier to occur of December 31, 2017 or notification from the Partnership of an event of default under the Third A&R Revolving Credit Agreement. In exchange for the amounts contributed pursuant to the Investment Agreement upon a Partial Investment Trigger or the Full Investment Trigger (as defined in the Investment Agreement), we will issue to Holdings, at Holdings' election, either (a) a number of common units at an issue price equal to either (i) if the common units are listed on a national stock exchange, 93% of the volume weighted average price of such common units for the twenty day period immediately preceding the date of the contribution or (ii) if the common units are not listed on a national stock exchange, the fair market value of such common units as reasonably agreed by us and Holdings or (b) a senior unsecured note of the Partnership in an initial face amount equal to the amount of the contribution by Holdings (an "Investment Note"). If Holdings elects to receive an Investment Note in exchange for a contribution pursuant to the Investment Agreement, such Investment Note will mature on or after November 5, 2019 and bear interest at a rate of 12.5% per annum payable in-kind prior to December 31, 2018 and in cash on or after December 31, 2018. The Investment Notes, if any, will be the unsecured obligation of the Partnership subordinate in right of payment to any of the Partnership's secured obligations under the Third A&R Revolving Credit Agreement and will contain covenants and events of default no more restrictive than those currently provided in the Third A&R Revolving Credit Agreement.

Pursuant to the Backstop Agreement, if Holdings is unable to satisfy its obligations under the Investment Agreement with cash on hand upon the occurrence of a Partial Investment Trigger or a Full Investment Trigger, the Sponsors have agreed to fund Holdings' shortfall in providing the Committed Amount by contributing each Sponsor's respective pro-rata portion of the shortfall to Holdings or, at the election of each Sponsor, directly to us. As consideration for any amounts contributed directly to us by a Sponsor pursuant to the Backstop Agreement, we will issue to such Sponsor the Common Units or Investment Note that would have otherwise been issued to Holdings under the Investment Agreement with respect to the amount contributed by the Sponsor.

Based upon the Partnership's financial forecast, amendments to the credit agreement (as discussed above), as well as the $15.0 million additional capital commitment from Holdings and the Sponsors, we believe management's executed plans provide the Partnership with sufficient liquidity to fund future operations through at least twelve months from the date that these financial statements were issued.

Holdings Chapter 11 Reorganization

On March 28, 2016, Holdings and certain of its subsidiaries (excluding us, our General Partner and our subsidiaries) filed a pre-packaged plan of reorganization (the "POR") under Chapter 11 of the U.S. Bankruptcy Code in the Southern District of Texas to restructure its debt obligations and strengthen its balance sheet. Our operations, customers, suppliers, partners and other constituents were excluded from such proceeding. On April 11, 2016, the bankruptcy court confirmed Holdings’ POR, and on April 13, 2016, Holdings and its subsidiaries emerged from bankruptcy with its Lenders being issued 33.34% of the limited partner interests in Holdings in exchange for the elimination of certain funded debt obligations. EIG and Tailwater each contributed $85 million in cash (or $170 million in the aggregate) in exchange for each Sponsor receiving 33.33% of the limited partner interests in Holdings. In addition, Holdings committed to provide us $50 million (the "Contribution Amount") (as part of the Equity Cure Agreement defined below), out of the $170 million in new equity contributed to Holdings from the Sponsors, to provide us with liquidity to comply with the applicable financial covenants set forth in our credit agreement at the time.

Table of contents

Distribution Suspension

The board of directors of our General Partner suspended paying a quarterly distribution with respect to the fourth quarter of 2015 and every quarter of 2016 to reserve any excess cash for the operation of our business. The board of directors of our General Partner and our management believe this suspension to be in the best interest of our unitholders and will continue to evaluate our ability to reinstate the distribution in future periods. Additionally, we are restricted under the fifth amendment to the Third A&R Revolving Credit Agreement from paying a distribution until our Consolidated Total Leverage Ratio is below 5.0. See Notes 2 and 4 to our 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. Due to the common control aspects in the 2015 Holdings Acquisition, the Partnership’s financial results retrospectively include the financial results for the Valley Wells System and the Compression Assets for all periods ending after August 4, 2014, the date that Southcross Energy LLC and TexStar Midstream Services, LP, a Texas limited partnership (“TexStar”), combined pursuant to a contribution agreement in which Holdings was formed (the “Holdings Transaction”). For additional details regarding the 2015 Holdings Acquisition, see Notes 1 and 3 to our consolidated financial statements.

General Trends and Outlook

Our business environment and corresponding operating results are affected by key trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results. Key trends that we monitor while managing our business include natural gas supply and demand dynamics overall and in our markets as well as growth production from U.S. shale plays, with specific attention on the Eagle Ford Shale region.

Natural Gas and NGL Environment

According to the US Energy Information Administration (the “EIA”), Texas leads the nation in natural gas production. Almost one-third of the 100 largest natural gas-producing fields in the United States are located, in whole or in part, in Texas. Much of the increase in production is the result of drilling in the Eagle Ford Shale region. Advances in horizontal drilling and hydraulic fracturing technologies, coupled with increased gas prices in the late 1990s, led to significant drilling activity. The Eagle Ford Shale produces substantial amounts of petroleum and natural gas liquids, along with natural gas, from more than 20 fields in 23 counties stretching across South Texas. More than one-fourth of the nation's proved natural gas reserves are located in Texas.

Total U.S. natural gas consumption averaged 75.1 billion cubic feet per day (Bcf/d) in 2016. The EIA expects natural gas consumption to increase by 0.3 Bcf/d (0.4%) in 2017 and by 1.5 Bcf/d (2.0%) in 2018. In 2017, increases in total natural gas consumption are mainly because of higher residential and commercial consumption based on a forecast of colder winter temperatures. In 2018, the electric power and industrial sectors are expected to be the main drivers of consumption growth. Based on forecasts by the National Oceanic and Atmospheric Administration (NOAA), EIA projects heating degree days (HDD) to be 6.7% higher in 2017 than in 2016, which had a warmer-than-normal winter. EIA expects residential and commercial natural gas consumption to increase by 6.0% and by 5.2%, respectively, in 2017. In 2018, residential and commercial consumption are both projected to be roughly unchanged from 2017 levels.

The EIA estimates that dry natural gas production averaged 72.4 Bcf/d in 2016, a decline of 1.8 Bcf/d (2.4%) from 2015. This decline is the first time annual average natural gas production has fallen since 2005. Production of marketed natural gas fell 1.8% in 2016 from 2015 levels. The higher decline rate for dry natural gas production compared with marketed production reflects higher rates of ethane recovery. The natural gas production is forecast to increase in 2017 and 2018, rising by 1.4 Bcf/d (2.0%) and by 2.8 Bcf/d (3.8%), respectively.

Natural gas pipeline exports increased by 1.0 Bcf/d (21.7%) to 5.9 Bcf/d in 2016, largely because of rising exports to Mexico. EIA expects pipeline exports of natural gas to continue rising because of growing demand from Mexico's electric power sector and because of flat natural gas production in Mexico. Gross pipeline exports are expected to increase by 0.1 Bcf/d in 2017 and by 0.4 Bcf/d in 2018.

Table of contents

Liquefied natural gas (LNG) exports increased from almost zero in 2015 to an average of 0.5 Bcf/d in 2016 with the startup of Cheniere's Sabine Pass LNG liquefaction plant in Louisiana, which sent out its first cargo in February 2016. LNG exports are expected to average 1.4 Bcf/d in 2017 as Sabine Pass ramps up capacity in the middle of the year. In 2018, LNG exports are forecast to average 2.6 Bcf/d. The 2018 growth is driven by the expected start of Cove Point LNG in Maryland in December 2017 and new projects at Cameron LNG and Freeport LNG on the Gulf Coast during the second half of 2018.

With expected growth in gross exports, net imports of natural gas decline from 1.7 Bcf/d in 2016 to 0.7 Bcf/d in 2017. The United States is expected to become a net exporter of natural gas for the year in 2018, with net exports averaging 0.6 Bcf/d.

Interest Rate Environment

In December 2016, interest rates were raised by the Federal Reserve for the second time since June 2006, signaling that rates may continue to rise in 2017. The Federal Reserve expects that economic conditions will evolve in a manner that will warrant gradual increases in interest rates three times in 2017, to a rate of 1.4 percent by the end of 2017. The gradual increases could affect our ability to access the debt capital markets to the extent we may need to in the future to fund our growth. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. The continued depressed natural gas, NGL and crude oil price environment also could affect negatively our ability to access the debt capital markets.

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 plant, 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, 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 generally are combined with fixed-fee and fixed-spread arrangements for processing services and, therefore, represent only a portion of a 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 related directly to the volume of natural gas that

Table of contents

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. For our gathering, transportation and other services agreements with Holdings (see Note 9 to our consolidated financial statements), fee based revenue increases with no associated cost of natural gas and liquids sold. We enter into primarily fixed-fee and fixed-spread deals.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our liquidity. 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 (i) volume, (ii) operations and maintenance expense, (iii) Adjusted EBITDA and (iv) 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.

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 liquidity 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, severance expense 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 a key metric used in measuring our compliance with our financial covenants under our debt agreements and is used as a supplemental measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- the ability of our assets to generate cash sufficient to support our indebtedness and make future cash distributions;
- 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 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

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 and net cash provided by operating activities are the GAAP measures most directly comparable to 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 Adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because 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.

Table of contents

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

	Year Ended December 31,	
	2016	2015
Net cash provided by operating activities	$50,902	$18,725
Add (deduct):		
Depreciation and amortization	(106,947)	(70,814)
Unit-based compensation	(3,523)	(4,573)
Amortization of deferred financing costs and PIK interest	(3,614)	(3,494)
Gain (loss) on sale of assets, net	11,768	(416)
Unrealized gain (loss) on financial instruments	147	(110)
Equity in losses of joint venture investments	(21,123)	(13,452)
Impairment of assets	(476)	(7,067)
Distribution from joint venture investment	(740)	(500)
Gain on legal settlements	2,375	—
Write-off of deferred financing costs	(1,006)	—
Other, net	310	82
Changes in operating assets and liabilities:		
Trade accounts receivable, including affiliates	(31,554)	3,069
Prepaid expenses and other current assets	(947)	495
Other non-current assets	358	(296)
Accounts payable and accrued expenses	18,234	24,559
Other liabilities, including affiliates	(9,112)	(1,701)
Net loss	$(94,948)	$(55,493)
Add (deduct):		
Depreciation and amortization	$106,947	$70,814
Interest expense	35,166	32,738
Unrealized loss on commodity swaps	—	111
Revenue deferral adjustment	3,016	3,016
Unit-based compensation	3,523	4,573
Income tax benefit	(2)	(233)
Loss (gain) on sale of assets, net	(11,768)	416
Major litigation costs, net of recoveries	495	513
Equity in losses of joint venture investments	21,123	13,452
Severance expense	472	956
Retention bonus funded by Holdings	3,168	—
Valley Wells' operating expense cap adjustments	2,406	2,670
Fees related to Equity Cure Agreement	650	—
Distribution from joint venture investment	740	500
Transaction-related costs	6	2,483
Impairment of assets	476	7,067
Gain on legal settlements	(3,939)	—
Write-off of deferred financing costs	1,006	—
Other, net	990	300
Adjusted EBITDA	$69,527	$83,883
Cash interest, net of capitalized costs	(32,459)	(32,293)
Income tax benefit	2	233

Maintenance capital expenditures	(4,711)	(11,618)
Distributable cash flow	$32,359	$40,205

57

Table of contents

QUARTERLY FINANCIAL INFORMATION

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

	Quarters ended			
	March 31	June 30	September 30	December 31
Net cash provided by operating activities	$(17,172)	$47,119	$11,256	$9,301
Add (deduct):				
Depreciation and amortization	(18,541)	(18,908)	(31,449)	(38,049)
Unit-based compensation	(981)	(725)	(929)	(888)
Amortization of deferred financing costs and PIK interest	(1,073)	(831)	(892)	(818)
Gain (loss) on sale of assets, net	—	12,576	179	(987)
Unrealized gain (loss) on financial instruments	(30)	85	61	31
Equity in losses of joint venture investments	(3,429)	(3,534)	(3,694)	(10,466)
Impairment of assets	—	—	(476)	—
Distribution from joint venture investment	(390)	—	(350)	—
Gain on legal settlements	—	—	—	2,375
Write-off of deferred financing costs	—	—	—	(1,006)
Other, net	121	62	63	64
Changes in operating assets and liabilities:				
Trade accounts receivable, including affiliates	(9,099)	(35,310)	(2,035)	14,890
Prepaid expenses and other current assets	14,127	(11,792)	(1,679)	(1,603)
Other non-current assets	280	(280)	63	295
Accounts payable and accrued expenses	18,663	9,145	(3,123)	(6,417)
Other liabilities, including affiliates	2,004	(5,003)	445	(6,194)
Net loss	$(15,520)	$(7,396)	$(32,560)	$(39,472)
Add (deduct):				
Depreciation and amortization	$18,541	$18,908	$31,449	$38,049
Interest expense	9,170	8,833	8,598	8,565
Income tax expense (benefit)	(5)	3	—	—
Loss (gain) on sale of assets, net	—	(12,576)	(179)	987
Revenue deferral adjustment	754	754	754	754
Unit-based compensation	981	725	929	888
Major litigation costs, net of recoveries	125	118	173	79
Transaction-related costs	6	—	—	—
Equity in losses of joint venture investments	3,429	3,534	3,694	10,466
Severance expense	—	16	—	456
Retention bonus funded by Holdings	898	898	898	474
Valley Wells' operating expense cap adjustments	991	1,415	—	—
Fees related to Equity Cure Agreement	510	67	12	61
Distribution from joint venture investment	390	—	350	—
Impairment of assets	—	—	476	—
Gain on legal settlements	—	—	—	(3,939)
Write-off of deferred financing costs	—	—	—	1,006
Other, net	426	300	240	24
Adjusted EBITDA	$20,696	$15,599	$14,834	$18,398

Key Factors Affecting Operating Results and Financial Condition

•

Acquisition of Holdings drop-down assets. In May 2015, we acquired gathering, treating, compression and transportation assets from Holdings and its subsidiaries consisting of the Valley Wells System's sour gas gathering and treating system with sour gas treating capacity of approximately 100 MMcf/d, which is supported by a 60 MMcf/d minimum volume commitment from Holdings for gathering and treating services. Holdings has producer contracts with minimum volume commitments totaling 35 MMcf/d behind the system. The system is connected to

Table of contents

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 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 Robstown and a propane pipeline from our Bonnie View fractionator to Robstown.

- Holdings' Lancaster Gas Treating Facility Fire. In February 2016, due to a fire, there was an outage at our Lancaster gas treating facility through April 2016. The outage at the Lancaster gas treating facility caused processed gas volumes and NGL production to decrease for the year ended December 31, 2016.

Table of contents

Results of Operations

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

	Year Ended December 31, 2016	Year Ended December 31, 2015 (1)
Revenues:		
Revenues	$451,271	$603,815
Revenues - affiliates	97,452	94,658
Total revenues	548,723	698,473
Expenses:		
Cost of natural gas and liquids sold	395,874	517,157
Operations and maintenance	70,242	82,529
Depreciation and amortization	106,947	70,814
General and administrative	28,546	30,026
Impairment of assets	476	7,067
Loss (gain) on sale of assets, net	(11,768)	416
Total expenses	590,317	708,009
Loss from operations	(41,594)	(9,536)
Other income (expense):		
Equity in losses of joint venture investments	(21,123)	(13,452)
Interest expense	(35,166)	(32,738)
Write-off of deferred financing costs	(1,006)	—
Gain on legal settlements	3,939	—
Total other expense	(53,356)	(46,190)
Loss before income tax benefit	(94,950)	(55,726)
Income tax benefit	2	233
Net loss	$(94,948)	$(55,493)
Other financial data:		
Adjusted EBITDA	$69,527	$83,883
Maintenance capital expenditures	$4,711	$11,618
Growth capital expenditures	$21,355	$93,718
Operating data:		
Average volume of processed gas (MMcf/d)	312	434
Average volume of NGLs produced (Bbls/d)	32,271	43,234
Average daily throughput Mississippi/Alabama (MMcf/d)	160	145
Realized prices on natural gas volumes ($/Mcf)	$2.34	$3.16
Realized prices on NGL volumes ($/gal)	0.34	0.36

(1) 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 financial results of the Valley Wells System and Compression Assets for all periods ending after August 4, 2014, the date of the Holdings Transaction.

Table of contents

2016 Compared with 2015

Volume and overview. Processed gas volumes decreased 122 MMcf/d, or 28%, to 312 MMcf/d during the year ended December 31, 2016, compared to 434 MMcf/d during the year ended December 31, 2015. This decrease was due primarily to a continued low commodity price environment for natural gas, crude oil and NGLs, a few customers electing to redirect gas away from our processing facilities and a fire at Holdings' Lancaster gas treating facility in February 2016 which caused an outage through April 2016.

NGLs produced at our processing plants for the year ended December 31, 2016 averaged 32,271 Bbls/d, a decrease of 25%, or 10,963 Bbls/d, compared to 43,234 Bbls/d for the year ended December 31, 2015. The decrease in NGLs produced was due primarily to a decline in processed gas volumes, as well as an outage at Holdings' Lancaster gas treating facility as noted above.

Revenue. Our total revenues for 2016 decreased $149.8 million, or 21%, to $548.7 million compared to $698.5 million in 2015. This decrease was due primarily to a decrease in realized prices in natural gas and NGLs, as well as a decrease in processed gas volumes resulting in revenue from sales of natural gas decreasing by $128.5 million and fee based transportation and processing revenue decreasing by $25.2 million for the year ended December 31, 2016 compared to the year ended December 31, 2015.

Cost of natural gas and NGLs sold. Our cost of natural gas and NGLs sold for the year ended December 31, 2016 was $395.9 million, compared to $517.2 million for the year ended December 31, 2015. This decrease of $121.3 million, or 23%, was due primarily to lower processed gas volumes and lower natural gas and NGL prices compared to the same period in 2015.

Operations and maintenance expenses. Operations and maintenance expenses for the year ended December 31, 2016 were $70.2 million, compared to $82.5 million for the year ended December 31, 2015. This decrease of $12.3 million, or 15%, was due primarily due to improved operating efficiencies at our facilities and lower variable expenses due to lower volumes.

General and administrative expenses. General and administrative expenses for the year ended December 31, 2016 were $28.5 million, compared to $30.0 million for the year ended December 31, 2015. This decrease of $1.5 million, or 5%, includes cost savings of $4.3 million partially offset by the $3.4 million associated with our nonrecurring employee retention plan. Additionally, in the third and fourth quarters of 2016, the accrual for the discretionary bonus was reduced.

Depreciation and amortization expense. Depreciation and amortization expense for the year ended December 31, 2016 was $106.9 million, compared to $70.8 million for the year ended December 31, 2015. The increase of $36.1 million, or 51%, was due primarily to accelerating the depreciation of our Conroe and Gregory facilities beginning August 2016 in response to us shutting down the Conroe facility and converting the Gregory facility to a compressor station during 2016.

Equity in losses of joint venture investments. Our share of losses incurred by our joint venture investments was $21.1 million for the year ended December 31, 2016 compared to $13.5 million for the year ended December 31, 2015. The increase of $7.6 million, or 56%, was due primarily to the impairment loss recorded against the T2 Cogen facility, at the joint venture level, during the fourth quarter of 2016. See Note 13 to our consolidated financial statements.

Impairment of assets. For the year ended December 31, 2016, we incurred impairment on our assets of $0.5 million, compared to $7.1 million for the year ended December 31, 2015. This decrease of $6.6 million was due primarily to impairment costs attributed to a spare turbine sold in 2015.

Interest expense. For the year ended December 31, 2016, interest expense was $35.2 million, compared to $32.7 million for the year ended December 31, 2015. This increase of $2.5 million, or 8%, was due primarily to higher average borrowings and higher interest rates on borrowings.

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 7 to our 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 Notes 2 and 7 to our consolidated financial statements.

Our future cash flow will be materially adversely affected if the prices for natural gas, NGL and crude oil reduces the drilling for oil or natural gas in the geographic areas in which we operate, primarily the Eagle Ford Shale region. See Notes 1 and 2 to our consolidated financial statements. The majority of our revenue is derived from fixed-fee and fixed-spread 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 portion of our contract portfolio contains minimum volume commitment arrangements. The majority of our volumes are dependent upon the level of producer drilling activity. With the current price environment and reduction in drilling activity, we have begun to implement cost saving initiatives to improve future cash flows.

In connection with Holdings' Chapter 11 reorganization, we entered into an equity cure contribution agreement (the “Equity Cure Agreement”) with Holdings that allowed us to cure any default under applicable Financial Covenants by having Holdings purchase equity interests in or make capital contributions to us, in an aggregate amount of up to the Contribution Amount. In exchange for the Contribution Amount, we issued Holdings a number of our common units representing limited partner interests equal to, subject to certain exceptions, (i) the applicable Contribution Amount divided by (ii) a common unit reference price (“Reference Price”) equal to the volume weighted daily average price of the common units on the New York Stock Exchange (“VWAP”) calculated for a period of 15 trading days ending two trading days prior to the contribution by Holdings. Notwithstanding the VWAP calculation, the Reference Price would be no less than $0.89 per common unit and no greater than $1.48 per common unit (the “Range”), and if the VWAP was within the Range for a period of 15 trading days, the first of which was April 7, 2016, such VWAP would be the Reference Price for all common units issued in exchange for the Contribution Amount. The Equity Cure Agreement remained in place through December 29, 2016, and was used to fund equity cures required to comply with the consolidated total leverage ratio of our Financial Covenants. See Note 10 to our consolidated financial statements for further discussion of our equity cure unit issuances.

On December 29, 2016, we entered into the Fifth Amendment, pursuant to which we received a full waiver for all defaults or events of default arising out of our failure to comply with the financial covenant to maintain a Consolidated Total Leverage Ratio less than 5.00 to 1.00 for the quarter ended September 30, 2016.

Additionally, pursuant to the Fifth Amendment, (i) the total aggregate commitments under the Third A&R Revolving Credit Agreement were reduced from $200 million to $145 million and the sublimit for letters of credit was also reduced from $75 million to $50 million (total aggregate commitments will be periodically reduced further through December 31, 2018); (ii) the Consolidated Total Leverage Ratio and Consolidated Senior Secured Leverage Ratio (each of which is defined in the Fifth Amendment) financial covenants were suspended until the quarter ended March 31, 2019; and (iii) the Consolidated Interest Coverage Ratio (as defined in the Fifth Amendment) financial covenant requirement was reduced from 2.50 to 1.00 to 1.50 to 1.00 for all periods ending on or prior to December 31, 2018 (the “Ratio Compliance Date”). Prior to the Ratio Compliance Date, we will be required to maintain minimum levels of Consolidated EBITDA on a quarterly basis and be subject to certain covenants and restrictions related to liquidity and capital expenditures. See Notes 2 and 7 to our consolidated financial statements.

In connection with the execution of the Fifth Amendment, on December 29, 2016, the Partnership entered into (i) the Investment Agreement with Holdings and Wells Fargo Bank, N.A., (ii) the Backstop Agreement with Holdings, Wells Fargo Bank, N.A. and the Sponsors and (iii) the Equity Cure Contribution Amendment with Holdings. See Notes 2 and 7 to the consolidated financial statements for additional details.

As of March 1, 2017, we had $553.8 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 $145.0 million (the "Credit Facility") less any letters of credit amounts outstanding, which as of March 1, 2017 provided us access to $9.3 million.

On July 25, 2016, we determined Holdings' cash contribution to us for the first quarter 2016 equity cure had not been transferred to us timely, as required under the Third A&R Revolving Credit Agreement, due to an administrative oversight, which resulted in a default. On July 26, 2016, Holdings fully funded the first quarter 2016 equity cure. On August 4, 2016, we entered into the Limited Waiver and Second Amendment to the Third A&R Revolving Credit Agreement whereby the lenders waived any default or right to exercise any remedy as a result of this technical event of default to fund timely the first quarter 2016 equity cure. See Item 1 regarding further waivers and amendments to our Third A&R Revolving Credit Agreement.

Table of contents

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):

	Year Ended December 31,	
	2016	2015
Maintenance capital	$4,711	$11,618
Growth capital	21,355	93,718
Total capital expenditures	$26,066	$105,336

Our growth capital expenditures during the year ended December 31, 2016 related primarily to various expansion and improvement projects primarily in our South Texas assets. The growth capital expenditures during the year ended December 31, 2015 related primarily to construction of the Valley Wells and Lancaster gathering and treating systems, and the timing of payments, $9.7 million of which related to 2014 activity that were paid in 2015, as well as various expansion and improvement projects primarily in our South Texas assets.

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 and the Investment Agreement with Holdings, as backstopped by the Sponsors, will provide sufficient liquidity to meet future short-term capital requirements through at least twelve months from the date that these financial statements were issued. Growth projects and acquisitions are key elements of our business strategy. We intend to finance our growth capital through several sources, including operating cash flows, borrowings under our Senior Credit Facilities and issuance of additional debt and equity securities. 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 long-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):

	Year Ended December 31,	
	2016	2015
Net cash provided by operating activities	$50,902	$18,725

Net cash used in investing activities	(8,904)	(127,837)
Net cash provided by (used in) financing activities	(32,120)	118,811

Table of contents

2016 Compared with 2015

Operating Activities—Net cash provided by operating activities was $50.9 million for the year ended December 31, 2016, compared to $18.7 million for the year ended December 31, 2015. The increase in cash provided by operating activities of $32.2 million primarily was the result of increased cash received on accounts receivable, including affiliates, and less cash applied toward accounts payable during the year ended December 31, 2016 compared to the year ended December 31, 2015.

Investing Activities—Net cash used in investing activities was $8.9 million for the year ended December 31, 2016, compared to $127.8 million for the year ended December 31, 2015. The decrease of $118.9 million relates primarily to decreased capital expenditures and acquisitions of $97.6 million and higher net cash proceeds received from sales of assets of $17.8 million during the year ended December 31, 2016.

Financing Activities—Net cash used in financing activities for the year ended December 31, 2016 was $32.1 million, compared to net cash provided by financing activities of $118.8 million for the year ended December 31, 2015. The decrease of $150.9 million was due primarily to reduced net borrowings of $176.5 million, partially offset by $29.4 million for equity cures and the $17.0 million contribution provided by Holdings to us during the year ended December 31, 2016.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Critical Accounting Policies

The accounting policies described below are considered critical to obtaining an understanding of our consolidated financial statements because their application requires significant estimates and judgments by management in preparing our consolidated financial statements. Management's estimates and judgments are inherently uncertain and may differ significantly from actual results achieved. Management considers an accounting estimate to be critical if the following conditions apply:

- the estimate requires significant assumptions; and
- changes in the estimate could have a material effect on our consolidated statements of operations or financial condition; or
- if different estimates that could have been selected had been used, there could be a material effect on our consolidated statements of operations or financial condition.

We have discussed the selection and application of these accounting estimates with the Audit Committee of the board of directors of our general partner and our independent registered public accounting firm. It is management's view that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates under different assumptions and conditions.

Revenue Recognition

Using the revenue recognition criteria of persuasive evidence that an exchange arrangement exists, delivery has occurred or services have been rendered and the price is fixed or determinable, we record natural gas and NGL revenue in the period when the physical product is delivered to the customer and in an amount based on the pricing terms of an executed contract. Our transportation, compression, processing, fractionation and other revenue is recognized in the period when the service is provided and includes our fee-based service revenue. In addition, collectability is evaluated on a customer-by-customer basis. New customers are subject to a credit review process, which evaluates the customers' financial position and their ability to pay.

Our sale and purchase arrangements primarily are accounted for on a gross basis in the statements of operations. These transactions are contractual arrangements that establish the terms of the purchase of natural gas or NGLs at a specified location and the sale of natural gas or NGLs at a different location on the same or on another specified date. These transactions require physical delivery and transfer of the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk.

Certain of our gas gathering agreements provide for a monthly, quarterly or annual minimum volume commitment ("MVC") from our customers. Under these MVCs, our customers agree to ship and/or process a minimum volume of production on our system or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to us at the end of the contracted measurement period if its actual throughput volumes are less than its MVC for that period. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent contracted measurement periods to the extent that such customer's throughput volumes in a subsequent contracted measurement period exceed its MVC for that period. We recognize customer billings for obligations under their MVCs as

Table of contents

revenue when the obligations are billable under the contract and the customer does not have the right to utilize shortfall payments to offset gathering fees in excess of its MVCs in subsequent periods.

Impairment of Long-Lived Assets

We evaluate our long-lived assets, which include finite-lived intangible assets, for impairment when events or circumstances indicate that their carrying values may not be recoverable. These events include, but are not limited to, market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, we evaluate the recoverability of our carrying value based on the long-lived asset's ability to generate future cash flows on an undiscounted basis. If the undiscounted cash flows are not sufficient to recover the long-lived asset's carrying value, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying values of the asset downward, if necessary, to their estimated fair value. Our fair value estimates generally are based on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted cash flows. We had no impairment of our assets during the year ended December 31, 2016, but we recorded $0.5 million related to the write-off of software costs. During the year ended December 31, 2015, we recorded $7.1 million of impairment cost related primarily to a write-down of a spare turbine.

New Accounting Pronouncements

For a complete description of new accounting pronouncements, see Note 1 to our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As a smaller reporting company, we are not required to provide the information required by Item 7A.

Table of contents

Item 8. Financial Statements and Supplementary Data
SOUTHCROSS ENERGY PARTNERS, L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Southcross Energy Partners GP, LLC and the unitholders of Southcross Energy Partners, L.P.
Dallas, Texas

We have audited the accompanying consolidated balance sheets of Southcross Energy Partners, L.P. and subsidiaries (the "Partnership") as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in partners' capital and cash flows for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Southcross Energy Partners, L.P. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Partnership has obtained a commitment from Southcross Holdings LP, which controls the Partnership's General Partner, to assist the Partnership in maintaining compliance with the terms of its debt agreements. This commitment has been backstopped by two of the owners of Southcross Holdings LP.

/s Deloitte & Touche LLP

Dallas, Texas
March 9, 2017

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

	December 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$21,226	$ 11,348
Trade accounts receivable	51,894	39,585
Accounts receivable - affiliates	7,976	49,734
Prepaid expenses	2,751	3,915
Other current assets	4,343	1,256
Total current assets	88,190	105,838
Property, plant and equipment, net	971,286	1,066,001
Investments in joint ventures	124,096	140,526
Other assets	2,504	6,595
Total assets	$1,186,076	$ 1,318,960
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$50,639	$ 66,458
Accounts payable - affiliates	524	7,871
Current portion of long-term debt	4,500	4,500
Other current liabilities	10,976	10,406
Total current liabilities	66,639	89,235
Long-term debt	543,872	604,518
Other non-current liabilities	11,936	3,871
Total liabilities	622,447	697,624
Commitments and contingencies (Note 8)		
Partners' capital:		
Common units (48,502,090 and 28,420,619 units outstanding as of December 31, 2016 and 2015, respectively)	255,124	271,236
Class B Convertible units (17,105,875 and 15,958,990 units issued and outstanding as of December 31, 2016 and 2015, respectively)	278,508	300,596
Subordinated units (12,213,713 units issued and outstanding as of December 31, 2016 and 2015)	19,240	37,920
General partner interest	10,757	11,584
Total partners' capital	563,629	621,336
Total liabilities and partners' capital	$1,186,076	$ 1,318,960

See accompanying notes to these consolidated financial statements.

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

	Year Ended December 31, 2016	2015
Revenues:		
Revenues	$451,271	$603,815
Revenues - affiliates	97,452	94,658
Total revenues (Note 12)	548,723	698,473
Expenses:		
Cost of natural gas and liquids sold	395,874	517,157
Operations and maintenance	70,242	82,529
Depreciation and amortization	106,947	70,814
General and administrative	28,546	30,026
Impairment of assets	476	7,067
Loss (gain) on sale of assets, net	(11,768)	416
Total expenses	590,317	708,009
Loss from operations	(41,594)	(9,536)
Other income (expense):		
Equity in losses of joint venture investments	(21,123)	(13,452)
Interest expense	(35,166)	(32,738)
Write-off of deferred financing costs	(1,006)	—
Gain on legal settlements	3,939	—
Total other expense	(53,356)	(46,190)
Loss before income tax benefit	(94,950)	(55,726)
Income tax benefit	2	233
Net loss	(94,948)	(55,493)
General partner unit in-kind distribution	(47)	(164)
Net loss attributable to Holdings	—	(4,258)
Net loss attributable to partners	$(94,995)	$(51,399)
Earnings per unit and distributions declared:		
Net loss allocated to limited partner common units	$(50,612)	$(24,790)
Weighted average number of limited partner common units outstanding	34,161	26,781
Basic and diluted loss per common unit	$(1.48)	$(0.93)
Distributions declared and paid per common unit	$—	$1.60
Net loss allocated to limited partner subordinated units	$(18,089)	$(11,300)
Weighted average number of limited partner subordinated units outstanding	12,214	12,214
Basic and diluted loss per subordinated unit	$(1.48)	$(0.93)

See accompanying notes to these consolidated financial statements.

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

	Year Ended December 31,	
	2016	2015
Cash flows from operating activities:		
Net loss	$(94,948)	$(55,493)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	106,947	70,814
Unit-based compensation	3,523	4,573
Amortization of deferred financing costs and PIK interest	3,614	3,494
Loss (gain) on sale of assets, net	(11,768)	416
Unrealized loss (gain) on financial instruments	(147)	110
Equity in losses of joint venture investments	21,123	13,452
Distribution from joint venture investment	740	500
Impairment of assets	476	7,067
Gain on legal settlements	(2,375)	—
Write-off of deferred financing costs	1,006	—
Other, net	(310)	(82)
Changes in operating assets and liabilities:		
Trade accounts receivable, including affiliates	31,554	(3,069)
Prepaid expenses and other current assets	947	(495)
Other non-current assets	(358)	296
Accounts payable and accrued liabilities	(18,234)	(24,559)
Other liabilities, including affiliates	9,112	1,701
Net cash provided by operating activities	50,902	18,725
Cash flows from investing activities:		
Capital expenditures	(26,066)	(108,698)
Insurance proceeds from property damage claims, net of expenditures	125	78
Net proceeds from sale of assets	22,470	4,693
Investment contribution to joint venture investments	(5,433)	(8,910)
Consideration paid for Holdings' drop-down acquisition	—	(15,000)
Net cash used in investing activities	(8,904)	(127,837)
Cash flows from financing activities:		
Borrowings under our credit facility	11,210	187,695
Repayments under our credit facility	(70,350)	(36,000)
Repayments under our term loan agreement	(4,500)	(4,500)
Payments on capital lease obligations	(419)	(528)
Financing costs	(1,366)	(698)
Tax withholdings on unit-based compensation vested units	(138)	—
Contributions from general partner	—	1,301
Common unit issuances to Holdings for equity contributions	29,416	—
Payments of distributions and distribution equivalent rights	—	(46,915)
Expenses paid by Holdings on behalf of Valley Wells' assets	—	17,858
Borrowing of senior unsecured PIK notes	14,000	—
Repayment of senior unsecured PIK notes and PIK interest	(14,260)	—
Valley Wells operating expense cap adjustments	4,053	1,023
Other, net	234	(425)
Net cash provided by (used in) financing activities	(32,120)	118,811

Net increase in cash and cash equivalents	9,878	9,699
Cash and cash equivalents — Beginning of year	11,348	1,649
Cash and cash equivalents — End of year	$21,226	$11,348

See accompanying notes to these consolidated financial statements.

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

	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	(24,730)	(14,225)	(11,256)	(1,024)	(4,258)	(55,493)
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	4,443	—	—	—	—	4,443
Cash distributions and distribution equivalent rights paid	(41,733)	—	(3,432)	(1,750)	—	(46,915)
Accrued distribution equivalent rights on long-term incentive plan	(718)	—	—	—	—	(718)
Tax withholdings on unit-based compensation vested units	(425)	—	—	—	—	(425)
General partner unit in-kind distribution	(112)	—	(53)	165	—	—
Valley Wells' operating expense cap adjustments	2,670	—	—	—	—	2,670
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	14,806	7,929	6,387	594	(29,716)	—
Expenses paid by Holdings on behalf of Valley Wells' assets	—	—	—	—	17,858	17,858
Interest related to receivable due from Holdings	—	—	—	75	—	75
Net liabilities assumed by Holdings in Holdings drop-down acquisition	—	—	—	—	1,436	1,436
BALANCE - December 31, 2015	$271,236	$300,596	$37,920	$11,584	$—	$621,336
Net loss	$(50,586)	$(24,383)	$(18,080)	$(1,899)	$—	$(94,948)
Unit-based compensation on long-term incentive plan	3,523	—	—	—	—	3,523
Accrued distribution equivalent rights on long-term incentive plan	11	—	—	—	—	11
Tax withholdings on unit-based compensation vested units	(138)	—	—	—	—	(138)
Common unit issuances to Holdings for equity cures and equity contributions	29,416	—	—	854	—	30,270
Interest on receivable from Holdings	—	—	—	233	—	233
Retention bonus funded by Holdings	936	—	—	—	—	936
	2,406	—	—	—	—	2,406

Valley Wells' operating expense cap adjustments						
General partner unit in-kind distribution	(26)	(12)	(9)	47	—	—
Class B Convertible unit in-kind distribution	(1,654)	2,307	(591)	(62)	—	—
BALANCE - December 31, 2016	$ 255,124	$ 278,508	$ 19,240	$ 10,757	$ —	$ 563,629

See accompanying notes to these consolidated financial statements.

71

Table of contents

1. ORGANIZATION, DESCRIPTION OF BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Organization and Description of Business

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.” 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 two gas processing plants, one fractionation facility and gathering and transportation pipelines. Southcross Holdings LP, a Delaware limited partnership (“Holdings”), indirectly owns 100% of Southcross Energy Partners GP, LLC, a Delaware limited liability company, our General Partner (“General Partner”) (and therefore controls us),

all of our subordinated and Class B convertible units and 54.6% of our common units. Our General Partner owns an approximate 2.0% interest in us and all of our incentive distribution rights.

Following the emergence of Holdings from its Chapter 11 reorganization proceeding on April 13, 2016 (see Note 2), EIG Global Energy Partners, LLC (“EIG”) and Tailwater Capital LLC (“Tailwater”) (collectively, the “Sponsors”) each indirectly own approximately one-third of Holdings, and a group of consolidated lenders under Holdings' term loan (the "Lenders") own the remaining one-third of Holdings.

Segments

Our chief operating decision-maker is the 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

The accompanying consolidated financial statements and related notes present the consolidated balance sheets as of December 31, 2016 and 2015 and the consolidated statements of operations, cash flows and changes in partners' capital for the years ended December 31, 2016 and 2015.

We recognized the 2015 Holdings Acquisition (defined in Note 3) 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 3.

The accompanying consolidated financial statements were prepared in accordance with accounting principles generally accepted in the U.S. ("GAAP") and in accordance with the rules and regulations of the U.S. Securities and Exchange Commission. Our consolidated financial statements include the accounts of Southcross and its 100% owned subsidiaries. We eliminate all intercompany balances and transactions in preparing consolidated financial statements. 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. See Note 15.

Principles of Consolidation

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. We do not have ownership in any consolidated variable interest entities.

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires management to make various estimates and assumptions that may affect the amounts of assets and liabilities, disclosures of contingent assets and liabilities at

72

Table of contents

the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Actual results may differ from those estimates.

Significant Accounting Policies

Revenue Recognition

Using the revenue recognition criteria of persuasive evidence of an exchange arrangement exists, delivery has occurred or services have been rendered and the price is fixed or determinable, we record natural gas and NGL sales revenue in the period when the physical product is delivered to the customer and in an amount based on the pricing terms of an executed contract. Our transportation, compression, processing, fractionation and other revenue is recognized in the period when the service is provided and represents our fee-based service revenue. In addition, collectability is evaluated on a customer-by-customer basis. New customers are subject to a credit review process, which evaluates the customers' financial position and their ability to pay.

Our sale and purchase arrangements primarily are accounted for on a gross basis in the statements of operations. These transactions are contractual arrangements that establish the terms of the purchase of natural gas or NGLs at a specified location and the sale of natural gas or NGLs at a different location on the same or on another specified date. These transactions require physical delivery and transfer of the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk.

We derive revenue in our business from the following types of 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.

Certain of our gathering and processing agreements provide for quarterly and annual minimum volume commitment ("MVC"). Under these MVCs, our customers agree to ship and/or process a minimum volume of production on our gathering systems or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to us at the end of the contracted measurement period if its actual throughput volumes are less than its MVC for that period. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent measurement periods to the extent that such customer's throughput volumes in a subsequent contracted measurement period exceed its MVC for that contracted measurement period.

We recognize customer billings for obligations under their MVCs as revenue when the obligations are billable under the contract and the customer does not have the right to utilize shortfall payments to offset gathering fees in excess of its MVCs in subsequent periods.

We record customer billings for obligations under their MVCs as deferred revenue when the customer has the right to utilize shortfall payments to offset gathering or processing fees in subsequent periods. We recognize deferred revenue under these arrangements in revenue once all contingencies or potential performance obligations associated with the

related volumes have either (i) been satisfied through the gathering or processing of future excess volumes of natural gas, or (ii) expired (or lapsed) through the passage of time pursuant to the terms of the applicable natural gas gathering agreement.
We classify deferred revenue as a current liability for arrangements where the expiration of a customer's right to utilize shortfall payments is 12 months or less.

Table of contents

Long-Lived Assets

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead and the cost of financing construction. Costs associated with obtaining rights of way agreements and easements to facilitate the building and maintenance of new pipelines are capitalized and depreciated over the life of the associated pipeline. We capitalize major units of property replacements or improvements and expense minor items. We use the straight-line method to depreciate property, plant and equipment over the estimated useful lives of the assets. We depreciate leasehold improvements and capital lease assets over the shorter of the life of the asset or the life of the lease. Maintenance and repairs are charged directly to expense as incurred, with the exception of substantial compression overhaul costs, which are capitalized and depreciated over the life of the overhaul.

Our intangible assets consist of acquired long-term supply and gas gathering contracts. We amortize these contracts on a straight-line basis over the 30-year expected useful lives of the contracts.

Impairment of Long-Lived Assets

We evaluate our long-lived assets by asset group, which include finite-lived intangible assets, for impairment when events or circumstances indicate that the asset group's carrying values may not be recoverable. These events include, but are not limited to, market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset or group, decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, we evaluate the recoverability of our carrying value based on the long-lived asset group's ability to generate future cash flows on an undiscounted basis. If the undiscounted cash flows are not sufficient to recover the long-lived asset group's carrying value, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying values of the asset downward, if necessary, to their estimated fair value. Our fair value estimates are based generally on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted cash flows. We had no impairment of our assets during the year ended December 31, 2016, but we recorded $0.5 million related to the write-off of software costs. During the year ended December 31, 2015, we recorded $7.1 million of impairment cost related primarily to a write-down of a spare turbine.

Cash and Cash Equivalents

We consider all short-term investments with an original maturity of three months or less to be cash equivalents. At December 31, 2016 and 2015, except for amounts held in bank accounts to cover current payables, all of our cash equivalents were invested in short-term money market accounts and overnight sweep accounts.

Allowance for Doubtful Accounts

In evaluating the collectability of our accounts receivable, we perform credit evaluations of our new customers and adjust payment terms based upon payment history and each customer's current creditworthiness, as determined by our review of such customer's credit information. We extend credit on an unsecured basis to many of our customers. In the event of a bankruptcy filing by a customer, we will determine if we will legally be able to collect any of the outstanding balance as a secured or unsecured creditor, and based on this determination we will reserve against part, or all, of the outstanding balance. We had an allowance for uncollectible accounts receivable of $0.1 million at December 31, 2015, which was written off during 2016.

Asset Retirement Obligations

We evaluate whether any future asset retirement obligations ("AROs") exist and estimate the costs for such AROs for certain future events. An ARO will be recorded in the periods where we can reasonably determine the settlement dates or the period in which the expense is incurred, and an estimated cost of the retirement obligation. Generally we do not have the intention of discontinuing the use of any significant assets or have a legal obligation to do so. Therefore, in these situations we do not have sufficient information to reasonably estimate any future AROs. No AROs were recorded for the years ended December 31, 2016 and 2015.

Environmental Costs and Other Contingencies

We recognize liabilities for environmental and other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and no specific amount in that range is more likely than any other, the low end of the range is accrued. No amounts were recorded as of December 31, 2016.

Table of contents

Fair Value of Financial Instruments

Accounting guidance requires the disclosure of the fair value of all financial instruments that are not otherwise recorded at fair value in the financial statements. At December 31, 2016 and 2015, financial instruments recorded at contractual amounts that approximate fair value include certain funds on deposit, accounts receivable, other receivables and accounts payable and accrued liabilities. The fair values of such items are not materially sensitive to shifts in market interest rates because of the short term to maturity of these instruments. See Note 5.

Derivative Instruments

In our normal course of business, we enter into month-ahead commodity swap contracts in order to hedge economically our exposure to certain intra-month natural gas index pricing risk. We manage our interest rate risk through interest rate swaps and interest rate caps. See Note 5.

Derivative financial instruments are recorded in the consolidated balance sheets at fair value, except for derivative contracts that qualify for and for which we have elected the normal purchase or normal sale exceptions, which are not reflected in the consolidated balance sheets or statements of operations prior to accrual of the settlement. If they qualify, we present our derivative assets and liabilities on a net basis.

We did not have any derivative financial instruments designated as fair value or cash flow hedges for accounting purposes during the years ended December 31, 2016 and 2015. Changes in our derivative financial instruments' fair values are recognized immediately in earnings. We do not hold or issue financial instruments or derivative financial instruments for trading purposes.

Unit-Based Compensation

Unit-based awards which settle in common units are classified as equity and are recognized in the financial statements over the vesting period at their grant date fair value. Unit-based awards which settle in cash are classified as liabilities and remeasured at every balance sheet date through settlement, such that the vested portion of the liability is adjusted to reflect its revised fair value through compensation expense. Currently, all awards granted under the Amended and Restated 2012 Long-Term Incentive Plan (the “LTIP”) will be settled in common units. Compensation expense associated with unit-based awards, adjusted for forfeitures, is recognized evenly from the date of the grant over the vesting period within operations and maintenance and general and administrative expense on our consolidated statements of operations.

Income Taxes

No provision for federal or state income taxes, except as noted below, is included in our statements of operations as such income is taxable directly to our partners. Each partner is responsible for its share of federal and state income tax. Net earnings for financial statement purposes may differ significantly from taxable income reportable to each partner as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

We are subject to the Texas margin tax which qualifies as an income tax under GAAP that requires us to recognize the impact of this tax on the temporary differences between the financial statement assets and liabilities and their tax basis. Our current tax liability will be assessed based on the gross revenue apportioned to Texas. For the years ended December 31, 2016 and 2015, there were no material temporary differences.

Uncertain Tax Positions

We evaluate the uncertainty in tax positions taken or expected to be taken in the course of preparing our consolidated financial statements to determine whether the tax positions are more likely than not of being sustained by the applicable tax authority. We believe that there are no uncertain tax positions and that no provision for income tax is required for these consolidated financial statements. As of December 31, 2016, tax years 2013 through 2016 remain subject to examination by the Internal Revenue Service and tax years 2012 through 2016 remain subject to examination by various state taxing authorities.

Earnings per Unit

Net loss per unit is calculated under the two-class method of computing earnings per unit when participating or multiple classes of securities exist. Under this method, undistributed earnings or losses for a period are allocated based on the contractual rights of each security to share in those earnings as if all of the earnings for the period had been distributed.

Basic net loss per unit excludes dilution and is computed by dividing net loss attributable to limited partner common units by the weighted average number of limited partner common units outstanding during the period. Paid-in kind distributions are excluded from income available to common units in the calculation of basic earnings per unit. Dilutive net loss per unit reflects potential dilution from the potential issuance of limited partner common units. Dilutive net loss per unit is calculated using the treasury stock method. It is computed by dividing net loss attributable to limited partner common units by the weighted average number of limited partner common units outstanding during the period increased by the number of additional limited partner common units that would have been outstanding if the dilutive potential limited partner common units had been issued.

Comprehensive Income (Loss)

Comprehensive income (loss) is the same as net income (loss) for periods presented in the consolidated financial statements.

Investments in Joint Ventures

We own equity interests in three joint ventures with Targa Pipeline Partners LP as our joint venture partner. We own a 50% or less equity interest in each of the three entities. The joint venture arrangements give equal management rights with no single investor having unilateral control. Each party sharing joint control must consent to the ventures' operating, investing and financing decisions. Therefore, because we do not have controlling financial interests, but do have significant influence, we use the equity method of accounting for investments in joint ventures. We recognize our share of the earnings and losses in the joint ventures pursuant to the terms of the applicable limited liability agreements governing such joint ventures, which provide for earnings and losses generally to be allocated based upon each member's respective ownership interest in the joint ventures. We record our proportionate share of the joint ventures' net income/loss as equity in income/losses of joint venture investments in the statements of operations. We evaluate investments in joint ventures for impairment when factors indicate that a decrease in the value of the investment has occurred that is not temporary. During the fourth quarter of 2016, as part of our cost-saving initiatives, management decided to significantly reduce the utilization of the T2 EF Cogeneration ("T2 Cogen") facility. In the immediate future, the T2 Cogen facility will only be utilized as a swing or backup facility for our Lone Star processing facility. As volumes are expected to increase in the ensuing years, management expects to need the generation capacity from the T2 Cogen facility to provide power to its Lone Star processing facility. As of December 31, 2016, management has no intention or plans to "mothball" or sell the T2 Cogen facility. See Note 13.

Recent Accounting Pronouncements

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

Adopted Accounting Pronouncements

In 2014, a new standard was issued that updated existing going concern guidance under GAAP. The new guidance relates to defining management's responsibility to evaluate whether there is substantial doubt about an organization's ability to continue as a going concern. Related disclosure in the notes to the consolidated financial statements are required surrounding whether it is probable that the entity will not be able to meet its obligations as they become due within one year after the date that financial statements are issued. We adopted this standard during the year ended December 31, 2016. See Note 2.

In February 2015, the Financial Accounting Standards Board ("FASB") issued a pronouncement that amended the consolidation guidance with regard to variable interest entities and voting interest entities. The standard became effective in 2016 and amended the guidance and framework for determining whether a partial-interest owner in a subsidiary should consolidate and potentially revise their disclosures about certain money market funds that are not within the scope of the variable interest entity guidance and the required transition disclosures in the fiscal period in which a change in accounting principle is made. We adopted this standard, which did not have a material impact to us, in 2016.

New Accounting Pronouncements

In February 2016, a pronouncement was issued amending disclosure and presentation requirements for lessees and lessors on the face of the balance sheet. The pronouncement states that a lessee should recognize a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term. When measuring assets and liabilities arising from a lease, a lessee (and a lessor) should include payments to be made in optional periods only if the lessee is reasonably certain to exercise an option to extend the lease or not to exercise an option to terminate the lease. Similarly, optional payments to purchase the underlying asset should be included in the measurement of lease assets and lease liabilities only if the lessee is reasonably certain to exercise that purchase option. In addition, also consistent with the previous leases guidance, a lessee (and a lessor) should exclude most variable lease payments in measuring lease assets and lease liabilities, other than those that depend on an index or a rate or are in substance fixed payments. This standard will become effective beginning in 2019.

Table of contents

In March 2016, a pronouncement was issued amending the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. This standard will become effective beginning in 2017.

In March 2016, the FASB issued a pronouncement amending the requirement to adopt retroactively the equity method of accounting. The pronouncement eliminates the requirement that when an investment qualifies for use of the equity method as a result of an increase in the level of ownership interest or degree of influence, an investor must adjust the investment, results of operations, and retained earnings retroactively on a step-by-step basis as if the equity method had been in effect during all previous periods that the investment had been held. The new guidance requires that the equity method investor add the cost of acquiring the additional interest in the investee to the current basis of the investor’s previously held interest and adopt the equity method of accounting as of the date the investment becomes qualified for equity method accounting. Therefore, upon qualifying for the equity method of accounting, no retroactive adjustment of the investment is required. In addition, the pronouncement requires that an entity that has an available-for sale equity security that becomes qualified for the equity method of accounting recognize through earnings the unrealized holding gain or loss in accumulated other comprehensive income at the date the investment becomes qualified for use of the equity method. This standard will become effective beginning in 2017.

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 April 2016, the FASB issued an accounting pronouncement which updates the identifying performance obligations and licensing implementation guidance. We are currently evaluating our contract mix, developing our implementation plan, and assessing the impact to our existing accounting policies and controls that will be impacted by the standard. The standard will become effective beginning in 2018.

In May 2016, the FASB issued a pronouncement for the new revenue recognition guidance on assessing collectability, presentation of sales taxes, non-cash consideration, completed contracts and contract modifications. The pronouncement is intended to reduce the potential for diversity in practice at initial application and cost and complexity on an ongoing basis. The standard will become effective beginning in 2018.

In August 2016, the FASB issued a pronouncement amending the presentation of how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The standard will become effective at the beginning of 2018.

2. LIQUIDITY CONSIDERATIONS

Our future cash flow will be materially adversely affected if the prices for natural gas, NGL and crude oil reduces the drilling for oil or natural gas in the geographic areas in which we operate, primarily the Eagle Ford Shale region. See Note 1 to our consolidated financial statements. The majority of our revenue is derived from fixed-fee and fixed-spread 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 portion of our contract portfolio contains minimum volume commitment arrangements. The majority of our volumes are dependent upon the level of producer drilling activity. With the current price environment and reduction in drilling activity, we have begun to implement cost saving initiatives to improve future cash flows.

In connection with Holdings' Chapter 11 reorganization, we entered into an equity cure contribution agreement (the “Equity Cure Agreement”) with Holdings that allowed us to cure any default under applicable Financial Covenants by having Holdings purchase equity interests in or make capital contributions to us, in an aggregate amount of up to $50 million (the "Contribution Amount"). In exchange for the Contribution Amount, we issued Holdings a number of our common units representing limited partner interests equal to, subject to certain exceptions, (i) the applicable Contribution Amount divided by (ii) a common unit reference price (“Reference Price”) equal to the volume weighted daily average price of the common units on the New York Stock Exchange (“VWAP”) calculated for a period of 15 trading days ending two trading days prior to the contribution by Holdings. Notwithstanding the VWAP calculation, the Reference Price would be no less than $0.89 per common unit and no greater than $1.48 per common unit (the “Range”), and if the VWAP was within the Range for a period of 15 trading days, the first of which was April 7, 2016, such VWAP would be the Reference Price for all common units issued in exchange for the Contribution Amount. The Equity Cure Agreement remained in place throughout 2016 and was used to fund equity cures totaling $12.4 million (excluding the $17.0 million discussed below) required to comply with the Consolidated Total Leverage Ratio of our Financial Covenants. See Note 10 for further discussion of our equity cure unit issuances.

Table of contents

On July 25, 2016, we determined Holdings' cash contribution to us for the first quarter 2016 equity cure had not been transferred to us timely, as required under the Third Amended and Restated Revolving Credit Agreement with Wells Fargo, N.A., UBS Securities LLC, Barclays Bank PLC and a syndicate of lenders (the "Third A&R Revolving Credit Agreement"), due to an administrative oversight, which resulted in a default. On July 26, 2016, Holdings fully funded the first quarter 2016 equity cure. On August 4, 2016, we entered into the limited waiver and second amendment to the Third A&R Revolving Credit Agreement whereby the lenders waived any default or right to exercise any remedy as a result of this technical event of default to fund timely the first quarter 2016 equity cure.

On November 8, 2016, we entered into a limited waiver and third amendment to the Third A&R Revolving Credit Agreement (the "Third Amendment"), which stipulated, among other things, that (i) the equity cure funding deadline for the quarter ended September 30, 2016 ("Q3 2016 Equity Cure") was extended from November 23, 2016 to December 16, 2016, and (ii) limited the total revolving credit exposure. On December 9, 2016, we entered into the fourth amendment to the Third A&R Revolving Credit Agreement (the "Fourth Amendment"), which stipulated, among other things, that (i) the deadline for funding the Q3 2016 Equity Cure was further extended from December 16, 2016 to January 12, 2017, and (ii) the Third A&R Revolving Credit Agreement was amended to require that any account into which we deposited funds, securities or commodities be subject to a lien and control agreement for the benefit of the secured parties under the Third A&R Revolving Credit Agreement.

On December 29, 2016, we entered into the fifth amendment to the Third A&R Revolving Credit Agreement (the "Fifth Amendment"), pursuant to which we received a full waiver for all defaults or events of default arising out of our failure to comply with the financial covenant to maintain a Consolidated Total Leverage Ratio less than 5.00 to 1.00 for the quarter ended September 30, 2016.

Additionally, pursuant to the Fifth Amendment, (i) the total aggregate commitments under the Third A&R Revolving Credit Agreement were reduced from $200 million to $145 million and the sublimit for letters of credit was also reduced from $75 million to $50 million (total aggregate commitments will be periodically further reduced through December 31, 2018); (ii) the Consolidated Total Leverage Ratio and Consolidated Senior Secured Leverage Ratio (periodically each of which is defined in the Fifth Amendment) financial covenants were suspended until the quarter ended March 31, 2019; and (iii) the Consolidated Interest Coverage Ratio (as defined in the Fifth Amendment) financial covenant requirement was reduced from 2.50 to 1.00 to 1.50 to 1.00 for all periods ending on or prior to December 31, 2018 (the "Ratio Compliance Date"). Prior to the Ratio Compliance Date, we will be required to maintain minimum levels of Consolidated EBITDA on a quarterly basis and be subject to certain covenants and restrictions related to liquidity and capital expenditures. See Note 7 to our consolidated financial statements.

In connection with the execution of the Fifth Amendment, on December 29, 2016, the Partnership entered into (i) an Investment Agreement (the "Investment Agreement") with Holdings and Wells Fargo Bank, N.A., (ii) a Backstop Agreement (the "Backstop Agreement") with Holdings, Wells Fargo Bank, N.A. and the Sponsors and (iii) a First Amendment to Equity Cure Contribution Agreement (the "Equity Cure Contribution Amendment") with Holdings. Pursuant to the Equity Cure Contribution Amendment, on December 29, 2016, Holdings contributed $17.0 million to us in exchange for 11,486,486 common units. The proceeds of the $17.0 million contribution were used to pay down the outstanding balance under the Third A&R Revolving Credit Agreement and for general corporate purposes. In addition, pursuant to entering into the Investment Agreement, the previous Equity Cure Contribution Agreement with Holdings was terminated and Holdings has agreed to contribute $15.0 million to us (the "Committed Amount") upon the earlier to occur of December 31, 2017 or notification from the Partnership of an event of default under the Third A&R Revolving Credit Agreement. In exchange for the amounts contributed pursuant to the Investment Agreement upon a Partial Investment Trigger or the Full Investment Trigger (as defined in the Investment Agreement), we will issue to Holdings, at Holdings' election, either (i) a number of common units at an issue price equal to either (a) if the common units are listed on a national stock exchange, 93% of the volume weighted average price of such common units for the twenty day period immediately preceding the date of the contribution or (b) if the common units are not listed on a national stock exchange, the fair market value of such common units as reasonably agreed by us and Holdings or (ii) a senior unsecured note of the Partnership in an initial face amount equal to the amount of the contribution by Holdings (an "Investment Note"). If Holdings elects to receive an Investment Note in exchange for a contribution pursuant to the

Investment Agreement, such Investment Note will mature on or after November 5, 2019 and bear interest at a rate of 12.5% per annum payable in-kind prior to December 31, 2018 and in cash on or after December 31, 2018. The Investment Notes, if any, will be our unsecured obligation to subordinate in right of payment to any of our secured obligations under the Third A&R Revolving Credit Agreement and will contain covenants and events of default no more restrictive than those currently provided in the Third A&R Revolving Credit Agreement.

Pursuant to the Backstop Agreement, if Holdings is unable to satisfy its obligations under the Investment Agreement with cash on hand upon the occurrence of a Partial Investment Trigger or a Full Investment Trigger, the Sponsors have agreed to

Table of contents

fund Holdings' shortfall in providing the Committed Amount by contributing each Sponsor's respective pro-rata portion of the shortfall to Holdings or, at the election of each Sponsor, directly to us. As consideration for any amounts contributed directly to us by a Sponsor pursuant to the Backstop Agreement, we will issue to such Sponsor the Common Units or Investment Note that would have otherwise been issued to Holdings under the Investment Agreement with respect to the amount contributed by the Sponsor.

Based upon the Partnership financial forecast, amendments to the credit agreement (as discussed above), as well as the $15.0 million additional capital commitment from Holdings and the sponsors, we believe management's executed plans provide the Partnership with sufficient liquidity to fund future operations through at least twelve months from the date that these financial statements were issued.

3. ACQUISITIONS

Holdings Drop-Down Acquisition. On May 7, 2015, we completed the acquisition of gathering, treating, compression and transportation assets (the "2015 Holdings Acquisition") consisting 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 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. 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 and issued to Holdings. We also assumed the remaining capital expenditures for the completion of the NGL pipelines that were under construction.

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 financial results of the Valley Wells System and Compression Assets for all periods ending after August 4, 2014 and before May 7, 2015. The acquired NGL pipelines were accounted for as an asset acquisition and were included in the historical financial statements beginning on May 7, 2015.

The amount of 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	107,356
Net assets contributed in excess of consideration paid	$29,716
Allocation of increase to partners' capital:	
Common limited partner interest	$14,806
Class B Convertible limited partner interest	7,929
Subordinated limited partner interest	6,387
General Partner interest	594
Total increase to partners' capital	$29,716

(1) Consists of $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 year ended December 31, 2015, are as follows (in thousands):

Table of contents

	Year Ended December 31, 2015
Partnership revenues	$691,424
Valley Wells System and Compression Assets revenue	7,049
Combined revenues	$698,473
Partnership net loss	$(51,235)
Valley Wells System and Compression Assets net loss	(4,258)
Combined net loss	$(55,493)

4. NET LOSS PER LIMITED PARTNER UNIT AND DISTRIBUTIONS

Net Loss Per Limited Partner Unit

The following is a reconciliation of net loss attributable to limited partners and the limited partner units used in the basic and diluted earnings per unit calculations for the years ended December 31, 2016 and 2015 (in thousands, except unit and per unit data):

	Year Ended December 31,	
	2016	2015 (1)
Net loss	$(94,948)	$(55,493)
General partner unit in-kind distribution	(47)	(164)
Net loss attributable to Holdings	—	(4,258)
Net loss attributable to partners	$(94,995)	$(51,399)
General partner's interest(1)	$(1,911)	$(1,084)
Class B Convertible limited partner interest(1)	(24,383)	(14,225)
Limited partners' interest(1)		
Common	$(50,612)	$(24,790)
Subordinated	(18,089)	(11,300)

(1) General Partner's and limited partners' interests are calculated based on the allocation of net losses for the period, net of the General Partner unit in-kind distributions. The Class B Convertible Unit ("Class B Convertible Units") interest is calculated based on the allocation of only net losses for the period.

	Year Ended December 31,	
Common Units	2016	2015
Interest in net loss	$(50,612)	$(24,790)
Effect of dilutive units - numerator(1)	—	—
Dilutive interest in net loss	$(50,612)	$(24,790)
Weighted-average units - basic	34,160,860	26,780,825
Effect of dilutive units - denominator(1)	—	—
Weighted-average units - dilutive	34,160,860	26,780,825
Basic and diluted net loss per common unit	$(1.48)	$(0.93)

Table of contents

	Year Ended December 31,	
Subordinated Units	2016	2015
Interest in net loss	$(18,089)	$(11,300)
Effect of dilutive units - numerator[(1)]	—	—
Dilutive interest in net loss	$(18,089)	$(11,300)
Weighted-average units - basic	12,213,713	12,213,713
Effect of dilutive units - denominator[(1)]	—	—
Weighted-average units - dilutive	12,213,713	12,213,713
Basic and diluted net loss per subordinated unit	$(1.48)	$(0.93)

(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 19,453 and 17,168 and unvested awards granted under our LTIP for the years ended December 31, 2016 and 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.

Distributions

Cash Distributions

The board of directors of our General Partner suspended paying a quarterly distribution with respect to the fourth quarter of 2015 and every quarter of 2016 to reserve any excess cash for the operation of our business. The board of directors of our General Partner and our management believe this suspension to be in the best interest of our unitholders and will continue to evaluate our ability to reinstate the distribution in future periods. Additionally, we are restricted under the fifth amendment to the Third A&R Revolving Credit Agreement from paying a distribution until our Consolidated Total Leverage Ratio is below 5.0.

Our agreement of limited partnership (as amended and restated, the “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. 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 First Amendment (as defined in Note 7) imposed additional restrictions on our ability to declare and pay quarterly cash distributions with respect to our subordinated units. See Note 7.

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.

The following table represents our distributions paid for previous periods (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	$11,368	$ —	$ 459	$11,827
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

Paid In-Kind Distributions

Class B Convertible Units. As of December 31, 2016, the Class B Convertible Units consisted of 17,105,875 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. These distributions will be paid quarterly in Class B PIK Units 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. 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 10.

The following table represents the PIK distribution paid on the Class B Convertible Units for periods ended December 31, 2015 and December 31, 2016 (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)]
2016						
February 14, 2017	December 31, 2016	$ 0.3257	299,375	$ 404	6,109	$ 8
November 24, 2016	September 30, 2016	0.3257	294,226	433	6,004	9
August 10, 2016	June 30, 2016	0.3257	289,165	581	5,901	12
May 9, 2016	(2)	0.3257	563,494	1,293	11,499	26
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

(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.

(2) We suspended distributions to holders of our Class B Convertible Units for the quarters ended December 31, 2015 and March 31, 2016. However, under the terms of our Partnership agreement, such paid in-kind ("PIK") distributions

continued to accumulate. On May 9, 2016, we issued the accumulated Class B Convertible Units to Holdings and general partner units to our General Partner related to the quarters ended December 31, 2015 and March 31, 2016.

Table of contents

5. 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:

- 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.
- 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 our Credit Facility (defined in Note 7) 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. As of December 31, 2016, the fair value of our term loan was $350.0 million, based on recent trading levels and is considered a Level 2 fair value instrument.

Derivative Financial Instruments

Interest Rate Derivative Transactions

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 December 31, 2016
100,000	1.195%	June 30, 2015	January 1, 2017	(15)

Effectively, we enter into interest rate cap contracts to limit our London Interbank Offered Rate ("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 December 31, 2016
$20,000	1.500%	December 31, 2014	December 31, 2016	—
80,000	3.000%	June 30, 2015	June 30, 2017	—

50,000	3.000%	December 31, 2015	December 31, 2017	—	
50,000	3.000%	June 30, 2016	June 30, 2018	4	
40,000	3.000%	December 31, 2016	January 1, 2018	—	
40,000	3.000%	December 31, 2016	July 1, 2018	3	
40,000	3.000%	December 31, 2016	January 1, 2019	14	
				$	21

83

Table of contents

In December 2016, we entered into three new interest rate cap contracts for $40.0 million notional values, each effective December 31, 2016. The new interest rate cap contracts provide for maturity dates of January 1, 2018, July 1, 2018 and January 1, 2019. The contracts effectively cap our LIBOR-based interest rate on the portion of debt at 3.0%.

These interest rate derivatives are not designated as cash flow hedging instruments for accounting purposes 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 December 31, 2016 and 2015.

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

	Significant Other Observable Inputs (Level 2) Fair Value Measurement as of	
	December 31, 2016	December 31, 2015
Current interest rate derivative assets	$2	$ 6
Non-current interest rate derivative assets	2	4
Current interest rate derivative (liabilities)	(15)	(169)
Total interest rate derivatives	$(11)	$ (159)

The realized and unrealized amounts recognized in interest expense associated with derivatives were as follows (in thousands):

	Year Ended December 31,	
	2016	2015
Unrealized gain on interest rate derivatives	$ (147)	$ (1)
Realized loss on interest rate derivatives	283	416

Commodity Swaps

In our normal course of business, we periodically enter into month-ahead swap contracts to hedge our exposure to certain intra-month natural gas index pricing risk. 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. We have elected to present our commodity swaps net on the balance sheets, however there are no offsetting liabilities for the periods presented. We had no outstanding commodity swaps at December 31, 2016 and December 31, 2015. We did not have any cash collateral received or paid on our commodity swaps as of December 31, 2016 and 2015. The realized and unrealized gain/loss on these derivatives, recognized in revenues in our statements of operations, were as follows (in thousands):

	Year ended December 31,	
	2016	2015
Realized gain on commodity swap derivatives	$ —	$ 214
Unrealized loss on commodity swap derivatives	—	(111)

84

Table of contents

6. LONG-LIVED ASSETS

Property, Plant and Equipment

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

	Estimated Useful Life	As of December 31, 2016	2015
Pipelines	15-30	$552,540	$542,790
Gas processing, treating and other plants	15	509,840	547,253
Compressors	5-15	72,054	72,750
Rights of way and easements	15	49,998	46,692
Furniture, fixtures and equipment	5	9,269	9,252
Capital lease vehicles	3-5	1,713	2,442
Total property, plant and equipment		1,195,414	1,221,179
Accumulated depreciation and amortization		(262,709)	(212,991)
Total		932,705	1,008,188
Construction in progress		16,150	32,214
Land and other		22,431	25,599
Property, plant and equipment, net		$971,286	$1,066,001

Depreciation is provided using the straight-line method based on the estimated useful life of each asset. Depreciation expense for the year ended December 31, 2016 included $32.5 million (the earnings per unit equivalent of $0.51 for the year ended December 31, 2016) of accelerated depreciation resulting from the assets' shortened useful life due to shutting down the Conroe facility and converting the Gregory facility to a compressor station in 2016. Depreciation expense for the year ended December 31, 2016 and 2015, was $106.9 million and $70.8 million, respectively.

We notified our producers that the Conroe plant would be idled by December 31, 2016. On August 4, 2016, the Gregory plant was idled while work commenced to convert the Gregory plant into a compressor station. The assets at the Gregory plant that will not be used as part of the compressor station will be sold or scrapped. The gas previously processed at the Gregory plant was re-rerouted to our Woodsboro facility during 2016 where we expect such gas to be processed going forward.

In May 2016, we finalized the sale of a portion of pipeline for $15.0 million, which was determined to be a sale of assets. We recorded a $13.6 million gain on sale of assets on our consolidated statement of operations in connection with this sale.

In January 2015, we shut down our Gregory facility for four weeks due to a fire at the facility. In December 2016, we reached a settlement related to the Gregory processing plant fire with our insurance carriers. We received the payment of $2.0 million from our insurance carriers in the first quarter of 2017 and used a portion of the proceeds to pay down on our term loan.

Intangible Assets

Intangible assets of $1.4 million and $1.5 million as of December 31, 2016 and 2015, 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.

Table of contents

7. LONG-TERM DEBT

Our outstanding debt and related information at December 31, 2016 and 2015 is as follows (in thousands):

	As of December 31,	
	2016	2015
Revolving credit facility due 2019	$122,555	$181,695
Term loans (including original issue discount of $1.5 million and $1.8 million as of December 31, 2016 and 2015, respectively) due 2021	437,291	441,464
Total long-term debt (including current portion)	559,846	623,159
Current portion of long-term debt	(4,500)	(4,500)
Debt issuance costs	(11,474)	(14,141)
Total long-term debt	$543,872	$604,518
Outstanding letters of credit	$19,378	$18,305
Remaining unused borrowings	$3,067	$—

	Year Ended December 31,	
	2016	2015
Weighted average interest rate	5.25 %	5.16 %
Average outstanding borrowings	$591,970	$564,568
Maximum borrowings	$628,055	$624,945

	Total	2017	2018	2019	2020	Thereafter
Maturity						
Long-term debt	$561,305	$4,500	$4,500	$127,055	$4,500	$420,750

Senior Credit Facilities

Our long-term debt arrangements consist of (i) the Third A&R Revolving Credit Agreement (as defined in Note 2) and (ii) a Term Loan Credit Agreement with Wilmington Trust, National Association, UBS Securities LLC and Barclays Bank PLC and a syndicate of lenders (the “Term Loan Agreement” and, together with the Third A&R Revolving Credit Agreement, the “Senior Credit Facilities”). 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 due August 4, 2019 (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 was set at $75.0 million;

(b) if we fail to comply with the consolidated total leverage ratio, consolidated senior secured leverage raio and the consolidate interest coverage ratio covenants (the "Financial Covenants") (a “Financial Covenant Default”), we have the right (a limited number times) 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

Amendments to 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, the lenders and other parties thereto (the "First Amendment").

Table of contents

The First Amendment, among other things:

(i) (a) revised the maximum consolidated total leverage ratio set at 5.25 to 1.0 as of the last day of the fiscal quarter ending September 30, 2016, and (b) 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;

(ii) 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%;

(iii) allowed 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. Beginning on January 1, 2017, we are limited to no more than four equity cures, with no more than two in a twelve month period. Additionally, we were unable to borrow on our Credit Facility until we have funded the required equity cure for the third quarter of 2016; however, we retained the ability to execute the required equity cure.

On July 25, 2016, we determined Holdings' cash contribution to us for the first quarter 2016 equity cure had not been transferred to us timely, as required under the Third A&R Revolving Credit Agreement, due to an administrative oversight, which resulted in a default. On July 26, 2016, Holdings fully funded the first quarter 2016 equity cure. On August 4, 2016, we entered into the limited waiver and second amendment to the Third A&R Revolving Credit Agreement whereby the lenders waived any default or right to exercise any remedy as a result of this technical event of default to fund timely the first quarter 2016 equity cure.

On November 8, 2016, we entered into the Third Amendment which stipulated, among other things, that i) the equity cure funding deadline for the quarter ended September 30, 2016 ("Q3 2016 Equity Cure") was extended from November 23, 2016 to December 16, 2016, and ii) the total revolving credit exposure (generally defined as funded borrowings plus letters of credit issued and outstanding) was limited to $145.2 million until the Q3 2016 Equity Cure was funded. The Third Amendment stipulated, among other things, that any Excess Cash Balance (generally defined as unrestricted book cash on hand that exceeds $15 million) as of the last business day of each week would be used to temporarily reduce funded borrowings under our revolving credit facility.

On December 9, 2016, we entered into the Fourth Amendment which stipulated, among other things, that i) the deadline for funding the Q3 2016 Equity Cure was further extended from December 16, 2016 to January 12, 2017, and ii) the Third A&R Revolving Credit Agreement was amended to require that any account into which we deposited funds, securities or commodities be subject to a lien and control agreement for the benefit of the secured parties under the Third A&R Revolving Credit Agreement.

On December 29, 2016, we entered into the Fifth Amendment which, among other things:

(i) permits a full waiver for all defaults or events of default arising out of our failure to comply with the financial covenant to maintain a Consolidated Total Leverage Ratio less than 5.00 to 1.00 for the quarter ended September 30, 2016;

(ii) reduced the total aggregate commitments under the Third A&R Revolving Credit Agreement from $200 million to $145 million and reduced the sublimit for letters of credit from $75 million to $50 million. Total aggregate commitments will be further reduced to $140 million on September 30, 2017, $135 million on December 31, 2017, $125 million on March 31, 2018, $120 million on June 30, 2018 and $115 million on December 31, 2018 and will also be reduced in an amount equal to the net proceeds of any Permitted Note Indebtedness we may incur in the future;

(iii) modified the borrowings under the Third A&R Revolving Credit Agreement to bear interest at the LIBOR or a base rate plus an applicable margin that cumulatively increases pursuant to the Amendment by (a) 125 basis points if our Consolidated Total Leverage Ratio is greater than or equal to 5.00 to 1.00, plus (b) 100 basis points if our Consolidated Total Leverage Ratio is greater than or equal to 6.00 to 1.00, plus (c) 100 basis points if our Consolidated Total Leverage Ratio is greater than or equal to 7.00 to 1.00, plus (d) 100 basis points if our Consolidated Total Leverage Ratio is greater than or equal to 8.00 to 1.00. At our election, the 100 basis point increase to the Applicable Margin upon our Consolidated Total Leverage Ratio being greater than or equal to 8.00 to 1.00 may be replaced with a 150 basis point increase that is payable in kind;

Table of contents

(iv) suspends the Consolidated Total Leverage Ratio and Consolidated Senior Secured Leverage Ratio financial covenants and reduces the Consolidated Interest Coverage Ratio financial covenant requirement from 2.50 to 1.00 to 1.50 to 1.00 for all periods ending on or prior to the Ratio Compliance Date;

(v) requires us to generate Consolidated EBITDA in certain minimum amounts beginning with the quarter ending December 31, 2016 and rolling forward thereafter through the quarter ending December 31, 2018;

(vi) requires us to maintain at least $3 million of Liquidity as of the last business day of each calendar week;

(vii) restricts our capital expenditures for growth and maintenance to not exceed certain amounts per fiscal year; and

(viii) beginning with the fiscal quarter ending March 31, 2019, our Consolidated Total Leverage Ratio cannot exceed 5.00 to 1.00 and our Consolidated Senior Secured Leverage Ratio cannot exceed 3.50 to 1.00. Until such time as our Consolidated Total Leverage Ratio is less than 5.00 to 1.00, we will also be restricted from making cash distributions to our unitholders and from entering into acquisition or merger agreements with third-party businesses involving a purchase price greater than $10 million, unless such acquisition is funded entirely using the proceeds from the issuance of equity. In addition, until such time as our Consolidated Total Leverage Ratio is less than or equal to 5.00 to 1.00, we will be required to repay any outstanding borrowings under the Third A&R Revolving Credit Agreement in an amount equal to 50% of our Excess Cash Flow.

On January 7, 2016, in response to our need for additional liquidity, we issued at par Senior Unsecured PIK Notes in the aggregate principal amount of $14 million (the "PIK Notes") to affiliates of EIG and Tailwater, with interest at a rate of 7% due January 7, 2017. Contemporaneous with the resolution of Holdings' bankruptcy proceedings in April 2016, the PIK Notes and the related PIK interest of $0.3 million were repaid in full.

Term Loan Agreement

The Term Loan Agreement is a seven-year $450 million senior secured term loan facility maturing on August 4, 2021. 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%. 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.

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 cost is included in long-term debt on the balance sheet. Changes in deferred financing costs are as follows (in thousands):

	Year Ended December 31,	
	2016	2015
Deferred financing costs, January 1	$14,141	$16,602
Capitalization of deferred financing costs	1,366	698
Write-off of deferred financing costs	(1,006)	—
Amortization of deferred financing costs	(3,027)	(3,159)
Deferred financing costs, December 31	$11,474	$14,141

8. COMMITMENTS AND CONTINGENT LIABILITIES

Legal Matters

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 currently are 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

Table of contents

litigation or claims ultimately will have a material effect on our results of operations, cash flows or financial condition in any future reporting periods.

Formosa. On March 5, 2013, one of our subsidiaries, Southcross Marketing Company Ltd., filed suit in a District Court of Dallas County 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. On December 30, 2016, we reached a final settlement with Formosa and the appeals have been dismissed. We were awarded $3.1 million, of which we received $1.6 million on December 30, 2016. We recorded a receivable of $1.6 million in our consolidated balance sheets as of December 31, 2016 for the remaining balance, which was received in January 2017.

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 classified as capital leases. The termination dates of the lease agreements vary from 2017 to 2019. We recorded amortization expense related to the capital leases of $0.4 million and $0.5 million for the years ended December 31, 2016 and 2015, respectively. Capital leases entered into during the years ended December 31, 2016 and 2015 were each $0.4 million. The capital lease obligation amounts included on the balance sheets were as follows (in thousands):

	December 31, 2016	December 31, 2015
Other current liabilities	$ 396	$ 362
Other non-current liabilities	497	522
Total	$ 893	$ 884

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 2017 to 2025. Expenses associated with operating leases, recorded in operations and maintenance expenses and general and administrative expenses in our statements of operations, were $5.8 million and $5.3 million for the years ended December 31, 2016 and 2015, respectively. A rental reimbursement included in our lease agreement associated with the office space we leased in June 2015 of $2.3 million was recorded as a deferred liability on our consolidated balance sheets as of December 31, 2016. This amount will be amortized against the lease payments over the length of the lease term.

Table of contents

Future Minimum Lease Payments

Future minimum annual rental commitments under our capital and operating leases at December 31, 2016 were as follows (in thousands):

Years Ending December 31,	Capital Leases	Operating Leases
2017	$ 396	$ 3,634
2018	291	3,477
2019	145	3,409
2020	61	2,912
2021	—	1,148
Thereafter	—	4,912
Total future payments	893	$ 19,492
Less: Imputed interest	$ —	
Future lease payments	$ 893	

9. TRANSACTIONS WITH RELATED PARTIES

Affiliated Directors

The board of directors of our General Partner is comprised of two directors designated by EIG (one of which must be independent), two directors designated by Tailwater (one of which must be independent), two directors designated by the Lenders (one of which must be independent) and one director by majority. 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):

	Year Ended December 31,	
	2016	2015
Charlesbank Capital Partners, LLC (1)	$97	$148
EIG	62	64
Tailwater	61	64
Total fees and expenses paid for director services to affiliated entities	$220	$276

(1) Charlesbank Capital Partners, LLC indirectly owned approximately one-third of Holdings until April 13, 2016. See Note 1.

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 their employees required to manage and operate our business. We incurred expenses related to these reimbursements as follows (in thousands):

	Year Ended December 31,	
	2016	2015
Reimbursements included in general and administrative expenses	$11,894	$15,790
Reimbursements included in operations and maintenance expenses	20,872	20,045
Total reimbursements to our General Partner and its affiliates	$32,766	$35,835

Compensation expense for services incurred by us on behalf of Southcross Energy LLC was billed to Southcross Energy LLC. Compensation expense not incurred on our behalf of $0.6 million for the year ended December 31, 2015 was billed to Southcross Energy LLC.

Table of contents

Other Transactions with Affiliates

On March 17, 2016, our General Partner entered into retention agreements with certain executives of our General Partner, pursuant to which the executives received a one-time special restructuring bonus in an amount equal to 100% of then-current annual salary for remaining employed with our General Partner through the date of Holdings' emergence from bankruptcy. The bonuses of $1.5 million were paid by Holdings on April 22, 2016.

In addition, on November 3, 2016, each of these executives of our General Partner received a one-time retention bonus in an amount equal to 100% of then-current annual salary for remaining employed with our General Partner through November 1, 2016. The bonuses of $1.5 million were paid by Holdings.

On January 7, 2016, in response to our need for additional liquidity, we issued the PIK Notes to affiliates of EIG and Tailwater, with interest at a rate of 7% due January 7, 2017. Contemporaneous with the resolution of Holdings' bankruptcy proceedings in April 2016, the PIK Notes and the related PIK interest of $0.3 million were repaid in full.

We have 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 commercial agreements, we transport, process and sell rich natural gas for the affiliate of Holdings in return for agreed-upon fixed fees, and we can sell natural gas liquids that we own to Holdings at agreed-upon fixed prices. The NGL Agreement also permits us to utilize Holdings' fractionation services at market-based rates. We had purchases of NGLs from Holdings of $10.0 million for the year ended December 31, 2016.

We have 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 was capped at $1.7 million per quarter through December 31, 2016. In the first and second quarters of 2016, we exceeded this cap by $1.0 million and $1.4 million, respectively. We did not exceed this cap in the third or fourth quarter of 2016.

We recorded revenues from affiliates of $97.5 million and $94.7 million for the years ended December 31, 2016 and 2015, respectively, in accordance with the G&P Agreement, the NGL Agreement and the series of commercial agreements.

We had accounts receivable due from affiliates of $8.0 million and $49.7 million as of December 31, 2016 and 2015, respectively, and accounts payable due to affiliates of $0.5 million and $7.9 million as of December 31, 2016 and 2015, 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). The receivable balance due from Holdings is current as of December 31, 2016.

During the year ended December 31, 2015, Holdings purchased $2.3 million of office leasehold improvements from us.

See Note 10 for our issuance of common units to Holdings.
In connection with the execution of the Fifth Amendment, on December 29, 2016, the Partnership entered into (i) the Investment Agreement with Holdings and Wells Fargo Bank, N.A., (ii) the Backstop Agreement with Holdings, Wells Fargo Bank, N.A. and the Sponsors and (iii) the Equity Cure Contribution Amendment with Holdings. See Notes 2

and 7 for additional details.

Table of contents

10. PARTNERS' CAPITAL

Ownership

Our units outstanding as of December 31, 2016 are as follows (in units):

	Partners' Capital				
		Owned By Parent			
	Public Common	Holdings 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
Common unit issuance related to the Holdings Acquisition	—	4,500,000	—	—	—
Board of Director grants	17,185	—	—	—	—
Vesting of LTIP units, net	102,491	—	—	—	—
In-kind distributions and general partner issuances to maintain 2.0% ownership	—	—	1,069,912	—	116,113
Units outstanding as of December 31, 2015	21,804,219	6,616,400	15,958,990	12,213,713	1,154,965
Vesting of LTIP units, net	205,797	—	—	—	—
In-kind distributions and issuances to general partner to maintain 2.0% ownership	—	—	1,146,885	—	433,233
Common unit issuances to Holdings related to equity cures	—	19,875,674	—	—	—
Units outstanding as of December 31, 2016	22,010,016	26,492,074	17,105,875	12,213,713	1,588,198

Common units

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

In accordance with the requirements of the Equity Cure Agreement, Holdings was issued 8,029,729 common units on May 2, 2016 for the fourth quarter 2015 equity cure of $11.9 million and 359,459 common units on May 13, 2016 for the first quarter 2016 equity cure of $0.5 million.

Pursuant to the Equity Cure Contribution Amendment, Holdings contributed $17.0 million to the Partnership in exchange for 11,486,486 common units on December 29, 2016. The proceeds of the $17.0 million contribution were used to pay down the outstanding balance under the Third A&R Revolving Credit Agreement and for general corporate purposes.

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

As of December 31, 2016, the Class B Convertible Units consist of 17,105,875 units, inclusive of any Class B paid in-kind ("PIK") Units issued. 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 December 31, 2016, all of our outstanding Class B Convertible Units were indirectly owned by Holdings.

Distribution Rights: 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.

Table of contents

We suspended distributions to holders of our Class B Convertible Units for the quarter ended December 31, 2015. However, under the terms of our Partnership agreement, such PIK distributions continued to accumulate. On May 9, 2016, we issued 563,494 Class B Convertible Units to Holdings and 11,499 general partner units to our General Partner related to the quarters ended December 31, 2015 and March 31, 2016, which were not previously issued. On August 10, 2016, we issued 289,165 Class B Convertible Units to Holdings and 5,901 general partner units to our General Partner related to the quarter ended June 30, 2016. On November 14, 2016, we issued 294,226 Class B Convertible Units to Holdings and 6,004 general partner units to our General Partner related to the quarter ended September 30, 2016. On February 14, 2017, we issued 299,375 Class B Convertible Units to Holdings and 6,109 general partner units to our General Partner for the quarter ended December 31, 2016.

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 (i) make a quarterly distribution equal to or greater than $0.44 per common unit, (ii) 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 (iii) 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.

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 7.

General Partner Interests

As defined by the 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 Class B Convertible Units. In connection with other equity issuances, our General Partner has made capital contributions in exchange for additional general partner units to maintain its 2.0% ownership interest in us. In connection with the 8,029,729 common units issued to Holdings on May 2, 2016 and the 359,459 common units issued to Holdings on May 13, 2016, our General Partner made capital contributions in exchange for 171,209 general partner units to maintain its 2.0% ownership interest in us. In connection with the 11,486,486 common units issued to Holdings on December 29, 2016, we recorded a receivable from our General Partner on our consolidated balance sheets in exchange for 234,419 general partner units to maintain its 2.0% ownership interest in us.

11. INCENTIVE COMPENSATION

Unit Based Compensation

Long-Term Incentive Plan

The 2012 Long-Term Incentive Plan ("LTIP") provides incentive awards to eligible officers, employees and directors of our General Partner. Awards granted to employees under the LTIP generally vest over a three year period in equal annual installments or in the event of a change in control, 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.

Table of contents

On November 9, 2015, the holders of a majority of our limited partnership units approved an amendment to the LTIP to increase the number of common units that may be granted as awards by 4,500,000 units. The term of the LTIP was also extended to a period of 10 years following the amendment's adoption.

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	594,333	11.82
Forfeited units	(204,530)	18.79
Units recaptured for tax withholdings (1)	(47,592)	8.41
Vested Units (1)	(125,041)	10.36
Unvested - December 31, 2015	687,920	$ 15.56
Granted units	47,500	3.56
Forfeited units	(73,493)	15.35
Units recaptured for tax withholdings (1)	(87,849)	16.42
Vested Units (1)	(205,797)	15.92
Unvested - December 31, 2016	368,281	$ 14.91

(1) The weighted-average fair value price on the date of vesting for our vested units was $1.57 and $9.17 for the years ended December 31, 2016 and 2015. The weighted-average fair value price on the date of vesting for our units recaptured for tax withholdings was $1.52 and $8.41 for the years ended December 31, 2016 and 2015.

For the years ended December 31, 2016 and 2015, we granted awards under the LTIP, with an aggregate grant date fair value of $0.2 million and $7.0 million which we have classified as equity awards. As of December 31, 2016 and 2015, we had total unamortized compensation expense of $3.1 million and $7.6 million related to unvested awards. Compensation expense associated with awards granted on March 10, 2015 of 84,423 units was recognized over a one-year vesting period, while compensation expense for the remaining awards is expected to be recognized over the three-year vesting period from each equity award's grant date. As of December 31, 2016 and 2015, we had 5,171,916 and 5,058,073, respectively, units 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 had a one-year vesting period rather than a three-year vesting period. These executive awards were not compensation earned for performance in 2015.

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):

	Year Ended December 31, 2016	2015
Unit-based compensation	$3,523	$4,573

Employee Savings Plan

We have employee savings plans under Sections 401(a) and 401(k) of the Internal Revenue Code, 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 the employee's contribution up to the lesser of 6% of the employee's eligible compensation or $15,900 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):

	Year Ended December 31,	
	2016	2015
Matching contributions expensed for employee savings plan	$1,252	$709

Table of contents

12. REVENUES

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

	Year Ended December 31,	
	2016	2015
Sales of natural gas	$271,302	$399,828
Sales of NGLs and condensate	158,968	154,478
Transportation, gathering and processing fees	113,482	138,717
Other	4,971	5,450
Total revenues	$548,723	$698,473

13. INVESTMENTS IN JOINT VENTURES

We own equity interests in three joint ventures with Targa Resources Corp. as our joint venture partner. T2 Eagle Ford Gathering Company LLC (“T2 Eagle Ford”), T2 LaSalle Gathering Company LLC (“T2 LaSalle”) and T2 Cogen operate pipelines and a cogeneration facility located in South Texas. 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. Our maximum exposure to loss related to these joint ventures includes our equity investment, any additional capital contributions and our share of any operating expenses incurred by the joint ventures.

We evaluate investments in joint ventures for impairment when factors indicate that a decrease in the value of the investment has occurred that is not temporary. During the fourth quarter of 2016, as part of firm wide cost-saving initiatives, management decided to significantly reduce the utilization of the T2 Cogen facility. In the immediate future, the T2 Cogen facility will be utilized only as a swing or backup facility for our Lone Star processing facility ("LS1"). As volumes are expected to increase in the ensuing years, management expects to need the generation capacity from the T2 Cogeneration facility to provide power to its LS1 facility. As the LS1 facility represents a more economical option to provide electricity to the Lone Star processing plant, management’s decision to reduce the utilization of the T2 Cogen substantially and as the electricity sales to FL Rich Gas Services represents the only source of revenue for T2 Cogen, the reduction in utilization significantly reduces the operating income associated with these assets. As a result in this change in the use of the T2 Cogen assets, T2 Cogen tested such assets for impairment, and recorded a $13.3 million impairment during the fourth quarter of 2016. We recorded our proportionate share (50%) of such impairment within equity in losses of joint venture investments.

The joint ventures’ summarized financial data from their statements of operations for the years ended December 31, 2016 and 2015 is as follows (in thousands):

	Year Ended December 31,	
	2016	2015
Revenue		
T2 Eagle Ford	$5,667	$6,850
T2 Cogen	2,556	2,437
T2 LaSalle	1,963	1,297
Net loss		
T2 Eagle Ford	$(19,312)	$(18,802)
T2 Cogen	(19,998)	(5,837)
T2 LaSalle	(5,872)	(5,860)

95

Table of contents

Our equity in losses of joint venture investments is comprised of the following for the years ended December 31, 2016 and 2015 (in thousands):

	Year Ended December 31,	
	2016	2015
T2 Eagle Ford	$(9,656)	$(9,068)
T2 Cogen	(9,999)	(2,919)
T2 LaSalle	(1,468)	(1,465)
Equity in losses of joint venture investments	$(21,123)	$(13,452)

Our investments in joint ventures is comprised of the following as of December 31, 2016 and 2015 (in thousands):

	December 31, 2016	December 31, 2015
T2 Eagle Ford	$101,669	$105,755
T2 Cogen	6,003	16,747
T2 LaSalle	16,424	18,024
Investments in joint ventures	$124,096	$140,526

The joint ventures' summarized balance sheet data is as follows (in thousands):

	December 31, 2016	December 31, 2015
T2 Cogen		
Current assets	$603	$1,986
Property, plant and equipment, net	12,000	32,333
Total assets	12,603	34,319
Total liabilities	596	824
Total equity	12,006	33,495
Total liabilities and equity	$12,603	$34,319
T2 Eagle Ford		
Current assets	$2,517	$4,525
Property, plant and equipment, net	203,810	217,370
Total assets	206,327	221,895
Total liabilities	2,173	9,697
Total equity	204,154	212,198
Total liabilities and equity	$206,327	$221,895
T2 LaSalle		
Current assets	$1,046	$1,228
Property, plant and equipment, net	66,028	71,491
Total assets	67,074	72,719
Total liabilities	1,262	622
Total equity	65,812	72,097
Total liabilities and equity	$67,074	$72,719

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.

96

Table of contents

Our top ten customers for the years ended December 31, 2016 and 2015 represent the following percentages of consolidated revenue:

	Year Ended December 31,	
	2016	2015
Top ten customers	53.5%	54.2%

The percentage of total consolidated revenue for each customer that exceeded 10% of total revenues for the years ended December 31, 2016 and 2015 was as follows:

	Year Ended December 31,	
	2016	2015
Trafigura AG	10.7%	(a)

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

For the years ended December 31, 2016 and 2015, we did not experience significant nonpayment for services. We had no allowance for uncollectible accounts receivable at December 31, 2016. We recorded an allowance for uncollectible accounts receivable of $0.1 million at December, 31, 2015, which was written off in 2016.

15. SUBSEQUENT EVENTS

None.

16. SUPPLEMENTAL INFORMATION

Supplemental Cash Flow Information (in thousands)

	Year Ended December 31,			
	2016		2015	
Supplemental Disclosures:				
Cash paid for interest	$	32,459	$	32,293
Cash received for tax refunds	52		58	
Supplemental schedule of non-cash investing and financing activities:				
Accounts payable related to capital expenditures	3,186		5,773	
Capital lease obligation	423		378	
Accrued distribution equivalent rights on the LTIP units	11		689	
Class B Convertible unit in-kind distributions	2,307		8,059	
Operating expenses for Valley Wells' assets due from Holdings	—		1,647	
Net assets contributed in Holdings drop-down	—		29,716	

acquisition in excess of consideration paid		
Purchase of assets in Holdings drop-down acquisition	—	62,640
Net liabilities assumed by Holdings in Holdings drop-down acquisition	—	1,436
Receivable from Holdings for purchase of office leasehold improvements	—	2,320
PIK interest	260	—
Common unit issuances to General Partner related to equity cures and equity contributions	854	—

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.

Table of contents

We incurred the following interest costs (in thousands):

	Year Ended December 31,	
	2016	2015
Total interest costs	$36,066	$34,517
Capitalized interest included in property, plant and equipment, net	(900)	(1,779)
Interest expense	$35,166	$32,738

Southcross Assets Considered Leases to Third Parties

We have pipelines that 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 agreement 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 December 31, 2016 were as follows: $5.6 million in 2017; $2.2 million in 2018; $2.2 million in 2019; $2.2 million in 2020 and $13.1 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 $2.6 million and $2.6 million for the years ended December 31, 2016 and 2015, 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 $3.0 million and $3.0 million for the years ended December 31, 2016 and 2015, respectively. Deferred revenue associated with these agreement was $8.5 million and $5.5 million at December 31, 2016 and 2015, respectively.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the direction of our general partner’s Chief Executive Officer and Chief Financial Officer, we evaluated our disclosure controls and procedures and concluded that our disclosure controls and procedures were effective as of December 31, 2016.

Management’s Report on Internal Control Over Financial Reporting

Our General Partner's management is responsible for establishing and maintaining adequate internal control over our financial reporting. With our participation, an evaluation of the effectiveness of our internal control over financial reporting was conducted as of December 31, 2016, based on the framework and criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on this evaluation, our General Partner’s management has concluded that our internal control over financial reporting was effective as of December 31, 2016.

This Form 10-K does not include an attestation report of our independent registered public accounting firm on internal control over financial reporting as a smaller reporting company and under an exemption established by the JOBS Act for “emerging growth companies.” As defined in Rule 12b-2 of the Exchange Act, we meet the criteria to be a smaller reporting company and have elected to use the reporting exemptions of a smaller reporting company in connection with the preparation of the consolidated financial statements as of December 31, 2016. Pursuant to the smaller reporting company requirements we are not required to to include an attestation report of our independent registered public accounting firm on internal control over financial reporting.

Changes in Internal Control

No change in internal control over financial reporting occurred during the quarter ended December 31, 2016, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

98

Table of contents

Item 9B. Other Information
None.

Item 10. Directors, Executive Officers and Corporate Governance
Management of Southcross Energy Partners, L.P.
Southcross Energy Partners, L.P. is managed by the directors and executive officers of our General Partner. Our General Partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. Holdings owns 100% of our General Partner. Our General Partner has a board of directors, and our unitholders are not entitled to elect the directors or to directly or indirectly participate in our management or operations. Our General Partner will be liable, as the General Partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our General Partner.
Director Independence
Although most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a listed publicly traded master limited partnership like us to have a majority of independent directors on the board of directors of its general partner.
Committees of the Board of Directors
The board of directors of our General Partner has an Audit Committee, a Conflicts Committee and a Compensation Committee and may have any such other committee as the board of directors shall determine from time to time. Each of the standing committees of the board of directors of our General Partner has the composition and responsibilities described below.
Conflicts Committee
Andrew A. Cameron, Nicholas J. Caruso, and Jerry W. Pinkerton serve as the members of our Conflicts Committee. Mr. Pinkerton serves as the chairman of the Conflicts Committee. Our Partnership Agreement provides that the Conflicts Committee, as delegated by the board of directors of our General Partner as circumstances warrant, will review conflicts of interest between us and our General Partner or between us and affiliates of our General Partner. If a matter is submitted to the Conflicts Committee for its review and approval, the Conflicts Committee will determine if the resolution of a conflict of interest that has been presented to it by the board of directors of our General Partner is fair and reasonable to us. The current members of the Conflicts Committee and any future members may not be officers or employees of our General Partner, directors, officers or employees of our General Partner's affiliates or a holder of any ownership interest in our General Partner, its affiliates or the Partnership, except for common units and certain awards given to directors in their capacity as a director. In addition, they must comply with the independence standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Any matters approved by the Conflicts Committee will be conclusively deemed to have been approved in good faith, to be fair and reasonable to us, approved by all of our partners and not a breach by our General Partner of any duties it may owe us or our unitholders.
Audit Committee
Andrew A. Cameron, Nicholas J. Caruso, and Jerry W. Pinkerton serve as the members of the Audit Committee. Mr. Pinkerton serves as the chairman of the Audit Committee. The Audit Committee oversees, reviews, acts on and reports on various auditing and accounting matters to the board of directors of our General Partner, including: (i) the selection of our independent accountants, (ii) the scope of our annual audits, (iii) fees to be paid to the independent accountants, (iv) the performance of our independent accountants, (v) the review of our internal controls process and (vi) our accounting practices. In addition, the Audit Committee oversees our compliance programs relating to legal and regulatory requirements. Messrs. Cameron, Caruso and Pinkerton comply with the independence and experience standards established by the NYSE and the Exchange Act for service on an audit committee of a board of directors. Our General Partner is generally required to have at least three independent directors serving on its board of directors at all times. Messrs. Cameron, Caruso and Pinkerton are each audit committee financial experts.
Mr. Ronald Steinhart served on the Audit Committee from January 1, 2016 through October 24, 2016, when Mr. Steinhart resigned. We received a letter from NYSE on October 26, 2016 indicating our deficiency in only having two

members on the Audit Committee and received a “BC” indicator on our ticker symbol on November 4, 2016 to denote that we were not in compliance with the NYSE’s continued listing standards. As noted below, when Mr. Cameron was elected to the board of

Table of contents

directors of our General Partner and the Audit Committee, effective as of January 1, 2017, the "BC" indicator was removed from our ticker symbol.

Compensation Committee

Andrew A. Cameron, Nicholas J. Caruso, and Jason H. Downie serve as members of the Compensation Committee. Mr. Downie serves as chairman of the Compensation Committee. The Compensation Committee establishes salaries, incentive compensation and other forms of compensation for officers, non-employee directors and other employees, as well as administers our incentive compensation and benefit plans.

Directors and Executive Officers

Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board of directors. The following table shows information for the directors and executive officers of our General Partner.

Name	Age	Position with Southcross Energy Partners GP, LLC
Bruce A. Williamson	57	Chairman, President and Chief Executive Officer
Bret M. Allan(1)	48	Senior Vice President, Chief Financial Officer and Principal Accounting Officer
Joel D. Moxley(1)	58	Senior Vice President and Chief Commercial Officer
Kelly J. Jameson(1)	52	Senior Vice President, General Counsel and Corporate Secretary
David W. Biegler(1)	70	Director
Andrew A. Cameron	57	Director
Nicholas J. Caruso	71	Director
Jason H. Downie(1)	46	Director
Wallace Henderson(1)	55	Director
Jerry W. Pinkerton	76	Director

(1) These directors and executive officers served as directors or executive officers of Southcross Holdings GP LLC ("Holdings GP") on March 28, 2016 when Holdings GP, Holdings and certain of Holdings' subsidiaries filed for bankruptcy. On April 11, 2016, the bankruptcy court confirmed Holdings' plan of reorganization, and on April 13, 2016, Holdings GP, Holdings and Holdings' subsidiaries emerged from bankruptcy.

Bruce A. Williamson

Mr. Williamson was elected as Chairman, President and Chief Executive Officer of our General Partner on January 6, 2017. Mr. Williamson joined the Board of the General Partner in April 2013 and served as an independent director designee of our sponsors as a result of contractual arrangements. Mr. Williamson previously served as a member of the Audit Committee, Compensation Committee and Conflicts Committee of the Board of our General Partner. In July 2016, Mr. Williamson became the Chairman of the Board of the general partner of Holdings and no longer was an independent director of the General Partner.

Mr. Williamson has over 35 years of experience encompassing all facets of the energy value chain. Most recently, Mr. Williamson was the President and Chief Executive Officer and director of Cleco Corporation, an energy services company, from July 2011 to April 2016 and was the Chairman, President and Chief Executive Officer at Dynegy, Inc., an energy services company, from 2002 through 2011. Prior to his role at Dynegy, Inc., Mr. Williamson was the President and Chief Executive Officer at Duke Energy Global Markets. Prior to Duke, Mr. Williamson was Senior Vice President Finance at PanEnergy Corp. and also worked for Shell Oil Company for 14 years in exploration and production in the United States and internationally.

Mr. Williamson received his bachelor's degree in finance from the University of Montana, and his master's in business administration from the University of Houston.

Joel D. Moxley

Joel D. Moxley was appointed Senior Vice President and Chief Commercial Officer of our General Partner in June 2015. Since June 2015, Mr. Moxley has also served as the Senior Vice President and Chief Commercial Officer of Holdings GP.

Table of contents

Before joining the General Partner and Holdings GP, Mr. Moxley served as Senior Vice President of Operations Services for Crestwood Equity Partners LP and Crestwood Midstream Partners LP (collectively, “Crestwood”), both midstream master limited partnerships until May 2015. The two entities were formed in May 2013 and October 2013, respectively, through a merger between Inergy, L.P. and Crestwood Holdings GP, which became collectively Crestwood Equity Partners LP, and a merger between Crestwood Midstream Partners LP and Inergy Midstream, L.P., which became collectively Crestwood Midstream Partners LP. Mr. Moxley’s responsibilities included oversight of a variety of functions including human resources, information technology, operational engineering, supply chain, risk management and safety and regulatory that supported Crestwood. From October 2010 to May 2013, Mr. Moxley was the Chief Operating Officer for Crestwood Holdings GP and Crestwood Midstream Partners LP, where Mr. Moxley was responsible for operations, commercial, engineering, environmental, safety, regulatory and supply chain activities. From April 2008 to October 2010, Mr. Moxley was a part of a team that evaluated midstream acquisition opportunities on behalf of a private equity sponsor that ultimately acquired Quicksilver Gas Services LP, a midstream master limited partnership, which was subsequently renamed Crestwood Midstream Partners LP. Prior to joining companies now affiliated with Crestwood, Mr. Moxley was Senior Vice President of Crosstex Energy, L.P. (“Crosstex”) with responsibility for the commercial activities of Crosstex’s South Louisiana gas processing and NGL fractionation assets as well as the marketing of NGLs for Crosstex companywide. Mr. Moxley’s experience also includes midstream leadership roles at Enterprise Products Partners L.P., El Paso Corporation, PG&E Corporation, Valero Energy Corporation and Occidental Petroleum.

Mr. Moxley received a bachelor’s degree in Chemical Engineering from Rice University. He is also a past Chairman of the Gas Processors Association and has served as a board member of the Texas Pipeline Association and the Petrochemical Feedstock Association of the Americas.

Bret M. Allan

Bret M. Allan was appointed Senior Vice President and Chief Financial Officer of our General Partner in June 2015. Effective December 2, 2016, Mr. Allan also assumed the responsibilities of principal accounting officer. Since June 2015, Mr. Allan additionally serves as the Senior Vice President and Chief Financial Officer of Holdings GP.

Prior to joining our General Partner and Holdings GP, Mr. Allan was Vice President, Finance and Treasurer for Energy Transfer Partners, L.P. From 2010 through 2015, Mr. Allan led the treasury, cash management, credit and corporate planning functions for Regency Energy Partners LP, a midstream master limited partnership within the Energy Transfer group. While at Regency, Mr. Allan helped lead numerous capital raising transactions and supported numerous acquisitions and recapitalizations.

Before joining Regency, Mr. Allan held various managerial positions at Energy Future Holdings and its predecessor company, TXU Corp., including positions in strategic planning, financial analysis and risk. Mr. Allan received a bachelor’s degree in economics from the University of California at Berkeley and holds a master’s degree in business administration with a concentration in finance from the University of Chicago Graduate School of Business.

Kelly J. Jameson

Kelly J. Jameson was appointed Senior Vice President, General Counsel and Corporate Secretary of our General Partner in September 2015. Since September 2015, Mr. Jameson has also served as the Senior Vice President, General Counsel and Corporate Secretary of Holdings GP.

Prior to joining our General Partner and Holdings GP, Mr. Jameson was Associate General Counsel at USA Compression Partners, LP having previously served as Senior Vice President, General Counsel and Corporate Secretary of Crestwood Midstream Partners from 2010 to 2013. Mr. Jameson was employed by TransCanada Corporation from 2007 to 2010, where he was Senior Counsel and Corporate Secretary for the U.S. subsidiaries of TransCanada Corporation. From 1996 to 2007, Mr. Jameson served as Senior Counsel and Assistant Corporate Secretary for El Paso Corporation, and from 1993 to 1996, he served as Vice President and General Counsel for Cornerstone Natural Gas Company, Inc. Mr. Jameson received a bachelor’s degree in business administration from Southern Methodist University and a juris doctor degree from Oklahoma City University. Mr. Jameson is a member of the Texas Bar Association.

David W. Biegler

David W. Biegler served as Chairman of the board of directors of our General Partner from August 2011 to January 6, 2017. On January 6, 2017, Mr. Biegler resigned as Chairman, but remains as a director of our General Partner. Mr. Biegler served as Chairman of the board of directors and Chief Executive Officer of our General Partner from August 2011 to December 2014 and as President of our General Partner from October 2012 to March 2014. From August 2014 to July 2016,

Table of contents

Mr. Biegler has also served as the Chairman of the board of directors of Holdings GP, and he served as Chief Executive Officer of Holdings GP through December 2014.

Mr. Biegler has more than 50 years of experience in the energy industry, having held various management positions in upstream, midstream, downstream, electric generation and oilfield services companies. From 2004 until 2012, Mr. Biegler served as chairman and chief executive officer of Estrella Energy LP, an entity formed for the purpose of acquiring midstream companies, which was a founding investor in our predecessor.

From 2002 to 2004, Mr. Biegler was Chairman of the board of Regency Gas Services, a midstream company that he co-founded and that was ultimately sold to a private equity firm. He retired as Vice Chairman of the board of TXU Corp. (now Energy Future Holdings Corp.) in 2001, a position he assumed earlier that year. From 1997 to 2001, Mr. Biegler served as President and Chief Operating Officer of TXU Corp., the result of a merger between Texas Utilities and ENSERCH Corp. From 1966 to 1997, he held various management positions at ENSERCH Corp. and its upstream, midstream, downstream and oilfield field services subsidiaries, including as ENSERCH’s Chairman, President and Chief Executive Officer from 1994 to 1997. Mr. Biegler received a bachelor’s degree in physics from St. Mary’s University, San Antonio, and is a graduate of Harvard University’s advanced management program.

Mr. Biegler also serves on the board of Southwest Airlines Co., Trinity Industries, Inc. and Austin Industries. He is a past director of Dynegy, Inc., Guaranty Financial Group and Animal Health International, Inc. He previously served as a member of the National Petroleum Council and as Chairman of the American Gas Association, the Southern Gas Association, the American Gas Foundation and the Texas Pipeline Association.

In connection with the Holdings Transaction, Mr. Biegler was selected to serve as Chairman for a two year term or until his earlier death or resignation by the majority of the directors of our General Partner, as a result of contractual arrangements. There are no current arrangements with Mr. Biegler.

Andrew A. Cameron

Andrew A. Cameron was elected as an independent member of the board of directors of our General Partner in January 2017. Mr. Cameron serves as a member of the Audit Committee, Conflicts Committee and Compensation Committee of the board of directors of our General Partner. Mr. Cameron has more than 37 years of experience in auditing, internal controls, finance and accounting. He retired as Vice President, Internal Audit and SOX Compliance of Vistra Energy, formerly Energy Future Holdings Corp., an electric utility company, in 2016. During the time Mr. Cameron served as Vice President, Internal Audit and SOX Compliance, Energy Future Holdings Corp. (now Vistra Energy) filed for Chapter 11 bankruptcy in April of 2014. Prior to his employment at Energy Future Holdings Corp., Mr. Cameron was Vice President and Controller from 2000 to 2004 at a subsidiary company of TXU Corp., an electric utility company and the predecessor company of Energy Future Holdings Corp., where he served in other finance and accounting roles from 1997 to 2000. Mr. Cameron served in various finance and audit positions with ENSERCH Corporation from 1984 to 1997. Mr. Cameron worked for KPMG from 1979 to 1984. Mr. Cameron received a bachelor’s degree in business and administration from the University of Strathclyde, Glasgow, Scotland and is a Certified Public Accountant.

The members of our General Partner appointed Mr. Cameron to serve as a director due to his audit, accounting and financial reporting expertise and knowledge that qualifies him as a financial expert for his role as a member of the Audit Committee.

Nicholas J. Caruso

Nicholas J. Caruso was elected as an independent member of the board of directors of our General Partner in July 2015. Mr. Caruso serves as a member of the Audit Committee, Conflicts Committee and Compensation Committee of the board of directors of our General Partner. Mr. Caruso has more than 45 years of management, finance and accounting experience. He was Executive Vice President and Chief Financial Officer of Dynegy Holdings, Inc. from 2002 through 2005, where he was responsible for the company’s treasury, insurance and audit functions. Prior to Dynegy, Mr. Caruso spent more than 30 years with Shell Oil Company in positions of increasing responsibility until his retirement in 2001. He last served as Shell’s Vice President of Finance and Chief Financial Officer from 1999 to 2002 and worked directly with Shell’s board of directors to implement internal controls and review financial results. Prior to being named CFO of Shell, Mr. Caruso served as its Controller and General Auditor. Mr. Caruso received a bachelor’s degree in accounting from Louisiana State University.

The members of our General Partner appointed Mr. Caruso to serve as a director due to his audit, accounting and financial reporting expertise and knowledge that qualifies him as a financial expert for his role as a member of the Audit Committee.

Table of contents

Jason H. Downie
Jason H. Downie was appointed to the board of directors of our General Partner in August 2014 and serves as Chairman of the Compensation Committee. Since August 2014, Mr. Downie has also served on the board of directors of Holdings GP.
Mr. Downie serves as Chairman of the Compensation Committee of the board of directors of our General Partner. Mr. Downie has more than 20 years of investment experience and co-founded Tailwater Capital, LLC in January 2013. At Tailwater, Mr. Downie's primary responsibilities include deal sourcing, transaction execution and monitoring of portfolio companies as well as executive leadership of Tailwater. Prior to co-founding Tailwater, Mr. Downie was a partner with HM Capital Partners, a private equity firm, from August 2000 to December 2012 and served on its investment committee. He joined HM Capital in August 2000 from Rice Sangalis Toole and Wilson, a mezzanine private equity firm, where he was an associate, from June 1999 until August 2000. Prior to Rice Sangalis Toole and Wilson, Mr. Downie was an associate in the equity trading group with Donaldson, Lufkin & Jenrette and was responsible for energy and transportation. Mr. Downie currently serves as a director of TW SWD & Solids Holdco LP, Pivotal Petroleum Partners LP, TSL Holdings I LP, Southcross Holdings GP LLC, Align Midstream Partners LP and Petro Waste Environmental. Mr. Downie received a bachelor's degree and master's degree in business administration from The University of Texas at Austin.
Mr. Downie serves as the director designee of Tailwater, one of our Sponsors, as a result of contractual arrangements entered into in connection with the Holdings Transaction. In addition to his affiliation with Tailwater, Mr. Downie was selected to serve as a director due to, his knowledge of the energy industry and his financial and business expertise.
Wallace C. Henderson
Wallace C. Henderson was appointed to the board of directors of our General Partner in August 2014. Since August 2014, Mr. Henderson has also served on the board of directors of Holdings GP.
Mr. Henderson has more than 25 years of energy banking and investment experience. He is currently a managing director and senior member of EIG's investment team where he oversees the firm's global investment activities in midstream oil and gas. Prior to joining EIG, Mr. Henderson was a senior financial consultant to Coskata, Inc., an energy technology company from May 2009 until May 2011. Mr. Henderson also spent five years with UBS where he ran the firm's New York-based energy group and led capital raising and advisory assignments for a wide range of energy companies and sponsors including EIG. Prior to his role with UBS, Mr. Henderson was an energy investment banker at Credit Suisse for 18 years where he specialized in oil and gas project finance, corporate capital raising and mergers and acquisitions for large U.S. and Latin American oil companies. He received a bachelor's degree in economics from Kenyon College and a master's in business administration from Columbia University.
Mr. Henderson serves as the director designee of EIG, one of our Sponsors, as a result of contractual arrangements entered into in connection with the Holdings Transaction. In addition to his affiliation with EIG, Mr. Henderson was selected to serve as a director on the board due to his knowledge of the energy industry and his financial and business expertise.
Jerry W. Pinkerton
Jerry W. Pinkerton was appointed as an independent member of the board of directors of our General Partner in April 2012. In addition, Mr. Pinkerton serves as Chairman of the Audit Committee and Chairman of the Conflicts Committee of the board of directors of our General Partner. With respect to the Audit Committee, Mr. Pinkerton qualifies as an "audit committee financial expert." Mr. Pinkerton has over 54 years of management, finance and accounting experience and has held various positions in several publicly traded companies. Mr. Pinkerton has served on the board of directors and a member of the audit committee of the general partner of Holly Energy Partners, L.P., a publicly traded master limited partnership that owns and operates petroleum product and crude oil pipeline and terminal, tankage and loading rack facilities, since July 2004, and as chairman of its audit committee until November 2016. From December 2000 to December 2003, Mr. Pinkerton served as a consultant to TXU Corp. (now Vistra Energy), and, from August 1997 to December 2000, he served as Controller of TXU Corp. and its U.S. subsidiaries. From August 1988 until its merger with TXU Corp. in August 1997, Mr. Pinkerton served as the Vice President and Chief Accounting Officer of ENSERCH Corporation. Prior to joining ENSERCH in August 1988, Mr. Pinkerton was

employed for 26 years as an auditor by Deloitte Haskins & Sells, a predecessor firm of Deloitte & Touche, LLP, including 15 years as an audit partner. From May 2008 to June 2011, Mr. Pinkerton also served on the board of directors of Animal Health International, Inc., an animal health distribution company, where he also served as chairman of its audit committee. Mr. Pinkerton received his bachelor's degree in accounting from The University of North Texas.

Mr. Pinkerton serves as an independent director designee of our Sponsors as a result of contractual arrangements entered into in connection with the Holdings Transaction. He was appointed due to his audit, accounting and financial reporting expertise and knowledge that qualifies him as a financial expert for his role as the chairman of the Audit Committee. Due to his executive managerial experience with public companies and public accounting firms and his prior board service, including audit committee experience, Mr. Pinkerton possesses business and management expertise and a broad range of expertise and knowledge of board committee functions.

Code of Ethics, Corporate Governance Guidelines and Board Committee Charters

Our General Partner has adopted a Code of Business Conduct and Ethics, which applies to our General Partner's directors, officers and employees. A waiver of the Code of Business Conduct and Ethics for any director or executive officer of our General Partner may be granted only by the Audit Committee, and such committee will report any such waiver to the board of directors of our General Partner. A waiver of the Code of Business Conduct and Ethics for other officers or employees may be granted only by our Chief Executive Officer, who will thereafter report any such waiver to the Audit Committee. The board of directors of our General Partner has also adopted Corporate Governance Guidelines, which outline the important policies and practices regarding our governance. Jerry W. Pinkerton serves as the lead director, as such term is used in the Corporate Governance Guidelines. The lead director is responsible for chairing the executive sessions required to be held by our General Partner's non-management directors. The Corporate Governance Guidelines permit the Chairman of the board of directors of our General Partner to designate another independent director to lead such meetings as the "Lead Director." Interested parties may communicate directly with the independent directors by submitting a communication in an envelope marked “Confidential” addressed to the “Independent Members of the Board of Directors” in care of Mr. Pinkerton at 1717 Main Street, Suite 5200, Dallas, Texas 75201.

We make available free of charge, within the "Investors" section of our website at www.southcrossenergy.com, and in print to any unitholder who so requests, our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Audit Committee Charter and Compensation Committee Charter. Requests for print copies may be directed to investorrelations@southcrossenergy.com or to: Investor Relations, Southcross Energy Partners, L.P., 1717 Main Street, Suite 5200, Dallas, Texas 75201, or telephone (214) 979-3720. We will post on our website all waivers to or amendments of the Code of Business Conduct and Ethics, that are required to be disclosed by applicable law and the NYSE's Corporate Governance Listing Standards. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our General Partner's board of directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file with the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10% unitholders are required by the SEC's regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they file with the SEC.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that, all reporting obligations of our General Partner's officers, directors and greater than 10% unitholders under Section 16(a) were satisfied during the year ended December 31, 2016.

Item 11. Executive Compensation

Executive Compensation Discussion

Overview of our Executive Compensation Program

This executive compensation discussion describes the compensation policies, programs, material components and decisions of the compensation committee of the board of directors of our General Partner (the “Compensation Committee”) with respect to our General Partner’s executive officers, including the following individuals who are referred to as our “Named Executive Officers” in 2016:

- John E. Bonn, President and Chief Executive Officer;
- Joel D. Moxley, Senior Vice President and Chief Commercial Officer; and
- Bret M. Allan, Senior Vice President and Chief Financial Officer.

Our General Partner's compensation practices and programs generally are designed to attract, retain and motivate exceptional leaders and structured to align compensation with our overall performance. The compensation practices and programs have been implemented to promote achievement of short-term and long-term business objectives consistent with our strategic plans and are applied to reward performance. To accomplish these objectives, the compensation program in 2016 consisted of the following components: (i) base salary, designed to compensate executive officers for work performed during the fiscal year; (ii) short-term retention compensation, designed to retain our talent; (iii) long-term incentive compensation in the form of cash awards, designed to retain our talent and compensate our executive officers, including our Named Executive Officers, for long-term service; and (iv) certain benefits, perquisites, retirement, severance and change in control arrangements.

Our General Partner, under the direction of its board of directors, is responsible for managing our operations and employs all of the employees that operate our business. We reimburse our General Partner, generally on a dollar-for-dollar basis, for the compensation attributable to the work performed on our behalf by its employees for work performed for us. Certain of the employees of our General Partner provide management, administrative, operational and workforce related services to our affiliates, including Holdings, which owns 100% of our General Partner, and an affiliate of our Sponsors.

Effective December 2, 2016, Mr. Allan also assumed the duties of principal accounting officer. Effective January 6, 2017, Mr. Bonn stepped down as President and Chief Executive Officer of our General Partner and Mr. Williamson was elected as Chairman, President and Chief Executive Officer of our General Partner.

References in this report to Named Executive Officers, executive officers, other officers, directors and employees refer to the Named Executive Officers, executive officers, other officers, directors and employees of our General Partner.

Role of the Compensation Committee and Management

Our General Partner is responsible for our management. The Compensation Committee is appointed by the board of directors of our General Partner to assist the board of directors in discharging its responsibilities relating to overall compensation matters, including, without limitation, matters relating to compensation programs for our directors and executive officers. The Compensation Committee is directly responsible for our General Partner’s compensation programs, which include programs that are designed specifically for our executive officers, including our Named Executive Officers.

The Compensation Committee has overall responsibility for evaluating and approving the compensation plans, policies and programs of our General Partner. To that end, the Compensation Committee has the responsibility, power and authority to set the compensation of executive officers, determine grant awards under and administer our General Partner’s equity compensation plans, and assume responsibility for all matters related to the foregoing. The Compensation Committee is charged, among other things, with the responsibility of reviewing the executive officer compensation policies and practices for (i) adherence to our compensation philosophy and (ii) ensuring that the total compensation paid to our executive officers is fair, reasonable and competitive. In 2016, these compensation programs for executive officers consisted of base salary, cash retention bonus awards, cash awards under our 2016 Cash-Based Long-Term Incentive Plan, as described below, as well as other customary employment benefits. Total compensation of executive officers and the relative emphasis of our main components of compensation are reviewed at least annually by the Compensation Committee, which then makes recommendations to the board of directors of our General Partner for its approval.

It is the practice of the Compensation Committee to meet in person or by conference call at least once a year for a number of purposes. These purposes include (i) assessing the performance of the Chief Executive Officer and other executive officers with respect to our results for the preceding year, (ii) establishing compensation levels for each executive officer for the ensuing year, (iii) determining the amount of the annual bonus pool approved by the board of directors of our General Partner to be paid to the executive officers, after taking into account both the target bonus levels established for those executive officers at the outset of the preceding year and the foregoing performance factors and (iv) determining cash awards under the 2016 Cash-Based Long Term Incentive Plan for executive officers and other key employees. Our Chief Executive Officer participates in the process of allocating our bonus pool and makes recommendations to the Compensation Committee regarding the amount of bonuses and other compensation paid to executive officers, other than to the Chief Executive Officer.

Compensation Components and Analysis

Base Salary. In March 2016, Mr. Bonn's base salary was increased from $450,000 to $500,000. In March 2016, Mr. Moxley's salary was increased from $385,000 to $397,000. In March 2016, Mr. Allan's salary was increased from $300,000 to $330,000. Base salaries for our Named Executive Officers will continue to be reviewed periodically by the Compensation Committee, with adjustment expected to be made generally in accordance with the considerations described above and to maintain base salaries at competitive levels.

Annual Performance-Based Compensation. Each of our Named Executive Officers is eligible to participate in an incentive bonus compensation program under which incentive awards are determined annually. For 2016, no discretionary bonuses were granted by the board of directors of our General Partner.

Long-Term Equity Participation. Please see the sections following our Summary Compensation Table (as defined below) for discussion regarding the long-term equity compensation granted to our Named Executive Officers.

Table of contents

Long-Term Cash Incentive. Please see the sections following our Summary Compensation Table for discussion regarding the long-term cash compensation granted to our Named Executive Officers.
Benefit Plans, Perquisites and Retirement. We provide our executive officers, including our Named Executive Officers, with a standard complement of health and retirement benefits under the same plans as all other employees, including medical, dental and vision benefits, disability and life insurance coverage, and a defined contribution plan that is tax-qualified under Section 401(k) of the Internal Revenue Code (the “401(k) Plan”). We believe that our health benefits provide stability to our Named Executive Officers, thus enabling them to better focus on their work responsibilities, while our 401(k) Plan provides a vehicle for tax-preferred retirement savings with additional compensation in the form of an employer match that adds to the overall desirability of our executive compensation package. For 2016, we provided an employer match under our 401(k) Plan equal to 100% of employee contributions up to 6% of eligible compensation, subject to the annual maximum contribution limit imposed by the Internal Revenue Service. None of our Named Executive Officers participated in any defined benefit pension plans or non-qualified deferred compensation plans.
Severance Agreements and Change in Control Provisions. We maintain severance and other compensatory agreements with our executive officers for a variety of reasons, including the fact that severance agreements can be an important recruiting tool in the market in which we compete for talent. Certain provisions in some of these agreements, such as confidentiality, non-solicitation and non-compete clauses, protect us and our unitholders after the termination of the employment relationship. We believe that it is appropriate to compensate former executives for these post-termination agreements, and that compensation helps to enhance the enforceability of these arrangements. These agreements are described in more detail below.
Retention Agreements. In 2016, we entered into retention agreements with our Named Executive Officers. These retention agreements award a cash incentive to retain our talent. Please see the sections following our Summary Compensation Table (as defined below) for discussion regarding the retention compensation granted to our Named Executive Officers.
Recoupment Policy. Equity awards granted under the LTIP are subject to recovery, including modification and forfeiture, for certain “Act[s] of Misconduct” as defined in the LTIP. We currently do not have a recovery policy applicable to annual cash bonuses, if any are awarded. The Compensation Committee will continue to evaluate the need to amend such a policy, in light of current legislative policies, and economic and market conditions.
2016 Summary Compensation Table
The following table (the "Summary Compensation Table") sets forth certain information with respect to the compensation paid to our Named Executive Officers for the years ended December 31, 2015 and 2016:

Name and Principal Position	Year	Salary ($)	Bonus($)(1)	Stock awards ($)(2)	All other compensation ($)(3)	Total ($)
John E. Bonn (4)	2016	489,423	1,000,000	—	16,584	1,506,007
President and Chief Executive Officer	2015	446,193	350,000	904,391	210,933	1,911,517
Joel D. Moxley (5)	2016	394,231	794,000	—	16,584	1,204,815
Senior Vice President and Chief Commercial Officer	2015	199,904	160,000	490,500	12,040	862,444
Bret M. Allan (6)	2016	323,077	660,000	—	16,584	999,661
Senior Vice President and Chief Financial Officer	2015	161,538	265,000	392,400	9,239	828,177

(1) For 2016, represents a $500,000 bonus paid to Mr. Bonn on each of April 22, 2016 and November 3, 2016; a $397,000 bonus paid to Mr. Moxley on each of April 22, 2016 and November 3, 2016; and a $330,000 bonus paid to Mr. Allan on each of April 22, 2016 and November 3, 2016. For 2015, represents bonus awards earned for performance in 2015 and paid on February 26, 2016. For 2015, also includes a $40,000 initial reporting bonus paid to Mr. Allan.
(2) For 2015, represents the grant date fair value of LTIP awards for Mr. Bonn based on the closing price on March 10, 2015 of $13.63 and the grant date fair value of LTIP awards for Messrs. Moxley and Allan on July 1, 2015 of $10.90. For assumptions used in determining the fair value of stock awards, see Note 11 to the consolidated

financial statements.

(3) For 2016, each of Messrs. Bonn, Moxley and Allan had a 401(k) match of $15,900. For 2016, includes life insurance premiums of Messrs. Bonn, Moxley and Allan in the amount of $684 each. For 2015, Mr. Bonn had a 401(k) match of $18,000 and reimbursement for interim living and relocation expenses of $192,249. For 2015, Mr. Moxley had a 401

106

Table of contents

(k) match of $11,698. For 2015, Mr. Allan had a 401(k) match of $8,897. For 2015, also includes life insurance premiums for Messrs. Bonn, Moxley and Allan.

(4) Mr. Bonn stepped down from our General Partner on January 6, 2017. See our Current report on Form 8-K, filed with the SEC on January 9, 2017.

(5) Mr. Moxley became employed by our General Partner on June 15, 2015.

(6) Mr. Allan became employed by our General Partner on June 8, 2015.

A discussion of the material compensation information disclosed in the Summary Compensation Table is set forth in the "Compensation Components and Analysis" section above and following is a discussion of other material factors necessary to understanding the total compensation afforded to our Named Executive Officers:

Named Executive Officer LTIP Units. On March 10, 2015, the board of directors of our General Partner granted 66,353 phantom units to Mr. Bonn (14,537 of which vest on the first anniversary of the grant date and 51,816 of which vest in three cumulative annual installments on the anniversary of the grant date). On July 1, 2015, the board of directors of our General Partner granted 45,000 phantom units to Mr. Moxley (all of which vest in three cumulative annual installments on the anniversary of the grant date) and 36,000 phantom units to Mr. Allan (all of which vest in three cumulative annual installments on the anniversary of the grant date).

Except for the LTIP awards with one-year vesting as indicated above, the phantom units awarded to our Named Executive Officers vest in three cumulative annual installments, with one-third of the units vesting on each anniversary of the grant date, subject to continued employment through the applicable vesting date. Each phantom unit granted to our Named Executive Officers in 2015 was granted in tandem with corresponding distribution equivalent rights (which are discussed below). Generally, upon the grantee’s cessation of employment, all phantom units that have not vested will be forfeited. Phantom units will vest in full upon a cessation of service due to death or disability or upon a change in control.

Amended and Restated Long-Term Incentive Plan. Under the LTIP, certain officers (including our Named Executive Officers), employees and directors are eligible to receive awards with respect to our equity interests, thereby linking the recipients’ compensation directly to our performance. The description of the LTIP set forth below is a summary of the material features of the LTIP. This summary does not purport to be a complete description of all of the provisions of the LTIP.

On October 28, 2015, the board of directors of our General Partner unanimously approved the Amended and Restated 2012 Long-Term Incentive Plan (the “Amended LTIP”), which is substantially similar to our 2012 Long Term Incentive Plan (the “2012 LTIP”). Effective as of December 7, 2015, the unitholders holding a majority of the Partnership’s outstanding limited partnership units approved the Amended LTIP by written consent in lieu of a special meeting of unitholders. The Amended LTIP increased the number of Partnership common units that may be granted as awards from 1,750,000 to 6,250,000 (inclusive of the 1,750,000 common units authorized under our 2012 LTIP), with such amount subject to adjustment as provided for under the terms of the Amended LTIP if there is a change in the common units, such as a unit split or other reorganization. The Amended LTIP also extended the term of the LTIP to a period of 10 years following its adoption. The term LTIP, as used here, means the 2012 LTIP as amended by the Amended LTIP. The LTIP awards granted to the Named Executive Officers in 2015 were granted prior to the adoption of the Amended LTIP.

The LTIP provides for the grant, from time to time at the discretion of the board of directors of our General Partner or the Compensation Committee, of restricted units, phantom units, unit options, distribution equivalent rights and other unit-based awards. Pursuant to the LTIP and subject to further adjustment in the event of certain transactions or changes in capitalization, an aggregate 6,250,000 common units may be delivered pursuant to awards under the LTIP. Units that are canceled or forfeited will be available for delivery pursuant to other awards. The LTIP is administered by the board of directors of our General Partner, although such administration function may be delegated to a committee (including the Compensation Committee) that may be appointed by the board of directors of our General Partner to administer the LTIP. The LTIP is designed to promote our interests, as well as the interests of our unitholders, by rewarding our directors, officers and employees for delivering desired performance results, as well as by strengthening our ability to attract, retain and motivate qualified individuals to serve as our directors, officers and employees.

Phantom Units. In 2016, there were no units granted under the LTIP to our named executive officers. In 2015, the only grants under the LTIP were phantom units. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. The administrator of the LTIP may make grants of

Table of contents

phantom units under the LTIP that contain such terms, consistent with the LTIP, as the administrator may determine are appropriate, including the period over which phantom units will vest. The administrator of the LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change in control (as defined in the LTIP) or as otherwise described in an award agreement.

The administrator of the LTIP, in its discretion, may also grant tandem distribution equivalent rights with respect to phantom units. Distribution equivalent rights are rights to receive an amount, in cash, units, restricted units and/or phantom units, equal in value to the distributions made on units during the period an award remains outstanding.

Source of Common Units; Cost. Common units to be delivered with respect to awards may be newly-issued units, common units acquired by us or our General Partner in the open market, common units already owned by our General Partner or us, common units acquired by our General Partner directly from us or any other person or any combination of the foregoing. With respect to awards made to employees of our General Partner, our General Partner will be entitled to reimbursement by us for the cost incurred in acquiring such common units or, with respect to unit options, for the difference between the cost it incurs in acquiring these common units and the proceeds it receives from an optionee at the time of exercise of an option. Thus, we will bear the cost of all awards under the LTIP. If we issue new common units with respect to these awards, the total number of common units outstanding will increase, and our General Partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash by our General Partner, our General Partner will be entitled to reimbursement by us for the amount of the cash settlement.

Amendment or Termination of LTIP. The administrator of the LTIP, at its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The LTIP will automatically terminate on the tenth anniversary of the date of the adoption of the Amended LTIP (as described above). The administrator of the LTIP also will have the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP, provided that no change in any outstanding award may be made that would impair materially the rights of the participant without the consent of the affected participant, and/or result in taxation to the participant under the Internal Revenue Code Section 409A.

2016 Cash-Based Long-Term Incentive Plan. On March 11, 2016, the board of directors of our General Partner approved the 2016 Cash-Based Long-Term Incentive Plan (the “2016 Cash LTIP”). The description of the 2016 Cash LTIP set forth below is a summary of the material features of the 2016 Cash LTIP. This summary does not purport to be a complete description of all of the provisions of the 2016 Cash LTIP.

The 2016 Cash LTIP provides for the grant, from time to time, of cash awards to certain of our employees. The 2016 Cash LTIP is administered by the board of directors of our General Partner, although such administration function may be delegated to a committee (including the Compensation Committee) comprised solely of two or more non-employee directors. The 2016 Cash LTIP is designed to promote our interests by strengthening our ability to retain and motivate employees.

Vesting Under 2016 Cash LTIP. Awards under the 2016 Cash LTIP (each, a “2016 Cash LTIP Award”) are determined by the Board or the Compensation Committee and are subject to the vesting of the cash award upon specified future dates. A third of each 2016 Cash LTIP Award granted to our named Executive Officers will vest on each of April 1, 2017, April 1, 2018, and April 1, 2019, subject to continued employment through the applicable vesting date. Generally, upon the grantee's cessation of employment, any cash awarded pursuant to a 2016 Cash LTIP Award that has not vested will be forfeited. However, if the employee is terminated without cause (as defined in the Amended LTIP), then such employee is entitled to receive the portion of the 2016 Cash LTIP Award that would have been payable on the next vesting date, but shall forfeit any further unvested 2016 Cash LTIP Award. A 2016 Cash LTIP Award shall vest in full, subject to continued employment through the certain event, upon a termination due to death or disability (as defined in the Amended LTIP) or a change of control (as defined in the 2016 Cash LTIP).

Amendment or Termination of 2016 Cash LTIP. The Board or the Compensation Committee may amend or terminate any 2016 Cash LTIP Award or the 2016 Cash LTIP in its discretion provided that any amendment or termination adverse to any employee under the 2016 Cash LTIP requires the consent of such employee. The 2016 Cash LTIP shall terminate on the date that all awards are paid.

2016 Cash LTIP Awards. On April 12, 2016, the board of directors of our General Partner awarded our Named Executive Officers cash awards under the 2016 Cash LTIP. The 2016 Cash LTIP Awards are not reflected in the Summary Compensation Table because the vesting dates did not occur in 2016.

Table of contents

The 2016 Cash LTIP Awards are as follows:

Name	Award Value
John E. Bonn (1)	$900,000
Joel D. Moxley (1)	$480,000
Bret M. Allan (1)	$390,000

(1) For Messrs. Moxley and Allan, a third of each of their 2016 Cash LTIP Award will vest on each of April 1, 2017, April 1, 2018, and April 1, 2019, subject to continued employment through the applicable vesting date.As noted herein, Mr. Bonn stepped down from our General Partner on January 6, 2017. Mr. Bonn received $300,000, which represents the portion of the 2016 Cash LTIP Award that would have been payable on the next vesting date of April 1, 2017.

Retention Agreements. On March 17, 2016, our General Partner entered into retention agreements (the "Retention Agreements") with Messrs. Bonn, Moxley and Allan. The description of the Retention Agreements set forth below is a summary of the material features of the Retention Agreements. This summary does not purport to be a complete description of all of the provisions of the Retention Agreements.

Pursuant to the Retention Agreements, Messrs. Bonn, Moxley and Allan each received (i) a one-time special restructuring bonus in an amount equal to 100% of his then-current annual salary for remaining employed with our General Partner through the date that Holdings emerged from bankruptcy and (ii) a one-time special retention bonus in the amount equal to 100% of his then-current annual salary for remaining employed with our General Partner through November 1, 2016. For 2016, under the Retention Agreements, Mr. Bonn received a total payment of $1,000,000, Mr. Moxley received a total payment of $794,000, and Mr. Allan received a total payment of $660,000. Each of these retention amounts were paid by Holdings.

All Other Compensation. Please see the discussions above for a discussion of the base salaries, short- and long-term incentive compensation, benefits, perquisites and retirement arrangements paid or made available to our Named Executive Officers. Please also see the section below entitled "Outstanding Equity Awards at December 31, 2016" for a discussion of outstanding equity awards and the section below entitled "Potential Payments Upon a Termination or Change in Control" for a discussion of payments made upon termination of employment and certain change in control events.

Outstanding Equity Awards at December 31, 2016

Southcross Energy Partners, L.P. Equity Awards. The following table provides information regarding LTIP units held by our Named Executive Officers as of December 31, 2016:

	Southcross Energy Partners, L.P. - LTIP Units	
Name	Number of time-vesting units that have not vested	Fair value of time-vesting units that have not vested(1)
John E. Bonn	53,361 (2)	$ 72,037
Joel D. Moxley	30,000 (3)	$ 40,500
	24,000 (4)	$ 32,400

Bret
M.
Allan

---

(1) Amounts were calculated based on the closing price per common unit on December 30, 2016 of $1.35.

(2) Represents the number of unvested time-vesting LTIP units awarded to Mr. Bonn on August 27, 2014 and March 10, 2015, subject to his continued employment through the applicable vesting date. For the August 27, 2014 grant, the 56,450 phantom units vest (on a one for one basis) in three cumulative annual installments on the anniversary of the grant. For the March 10, 2015 grant, 51,816 phantom units vest (on a one for one basis) in three cumulative annual installments on the anniversary of the grant date and 14,537 phantom units vest (on a one for one basis) on the first anniversary of the grant date. 31,809 phantom units that were granted on March 10, 2015 vested on March 10, 2016. 18,817 phantom units that were granted on August 27, 2014 vested on August 27, 2016. On January 6, 2017, Mr. Bonn stepped down from our General Partner and forfeited his unvested LTIP awards.

(3) Represents the number of unvested time-vesting LTIP units awarded to Mr. Moxley on July 1, 2015, subject to his continued employment through the applicable vesting date. The units vest (on a one for one basis) in three cumulative annual installments on the anniversary of the grant date. 15,000 phantom units of the 45,000 phantom units owned by Mr. Moxley vested on July 1, 2016.

Table of contents

(4) Represents the number of unvested time-vesting LTIP units awarded to Mr. Allan on July 1, 2015, subject to his continued employment through the applicable vesting date. The units vest (on a one for one basis) in three cumulative annual installments on the anniversary of the grant date. 12,000 phantom units of the 36,000 phantom units owned by Mr. Allan vested on July 1, 2016.

Potential Payments Upon a Termination or Change in Control

Severance and Change in Control Benefits. Our Named Executive Officers are entitled to severance payments and benefits upon certain terminations of employment and, in certain cases, upon a change in control.

Messrs. Moxley and Allan entered into severance agreements with our General Partner that provide for severance benefits upon certain terminations of employment. Mr. Bonn had an employment agreement with our General Partner that provided for severance benefits upon certain terminations of his employment. Mr. Bonn stepped down on January 6, 2017. Bruce Williamson entered into an employment agreement with our General Partner on January 6, 2017.

Mr. Bonn's Severance and Change in Control Benefits. On March 5, 2015, our General Partner entered into an employment agreement with John E. Bonn, who served as President and Chief Executive Officer of our General Partner (the “Bonn Employment Agreement”). The Bonn Employment Agreement provided for an initial three-year term, unless earlier terminated. The Bonn Employment Agreement automatically extended for one year periods unless notice was given otherwise prior to the expiration of the then-current term. Mr. Bonn was entitled to receive an annual base salary of $450,000 for the first year, $500,000 for the second year and not less than $500,000 for each year thereafter, as determined by the board of directors of our General Partner. Mr. Bonn was eligible to receive an annual cash bonus based on annual performance targets in an amount determined by the board of directors of our General Partner in its discretion with a target annual bonus equal to Mr. Bonn’s salary for such year. Mr. Bonn was also eligible to receive LTIP awards as determined by the board of directors of our General Partner. Mr. Bonn was also entitled to receive certain benefits and reimbursement of certain expenses, including relocation expenses.

By virtue of the Bonn Employment Agreement, upon his termination without “cause” on January 6, 2017, Mr. Bonn was entitled to receive (i) a payment consisting of (a) any portion of Mr. Bonn’s Annual Base Salary through the date of termination that was unpaid, (b) any expenses owed to Mr. Bonn, (c) any accrued and unused paid time off owed to Mr. Bonn, (d) any amount arising under any employee benefit plans, and (e) payment of an Annual Bonus earned in 2016, but unpaid; and (ii) a Severance Payment of (a) two times his then-current annual base salary, (b) two times his target annual bonus for 2017, (c) an amount equal to the cost of COBRA coverage for 18 months after termination and (d) $100,000 since Mr. Bonn was terminated during the second year of the Bonn Employment Agreement, subject to Mr. Bonn complying with certain restrictions in a severance agreement and the terms of other ancillary agreements to which Mr. Bonn is a party. On February 21, 2017, Mr. Bonn executed a Severance Agreement and General Release and will receive severance payments over the next ten months pursuant to the Bonn Employment Agreement.

With regard to Mr. Bonn’s 2016 Cash LTIP Award, since Mr. Bonn was terminated without cause (as defined in the LTIP), Mr. Bonn was entitled to receive the portion of the 2016 Cash LTIP Award that would have been payable on the next vesting date, but forfeited any further unvested 2016 Cash LTIP Award. A 2016 Cash LTIP Award would have vested in full, subject to continued employment through the certain event, upon a termination due to death or disability (as defined in the LTIP) or a change of control (as defined in the 2016 Cash LTIP). For additional information regarding the vesting of Mr. Bonn’s 2015 Cash LTIP Award, see the discussion under the Summary Compensation Table above.

For one year following his termination, Mr. Bonn is subject to certain non-competition and non-solicitation provisions set forth in the Bonn Employment Agreement. Mr. Bonn is also subject to certain confidentiality provisions after his employment.

Mr. Moxley's Severance and Change in Control Benefits. Under Mr. Moxley's severance agreement, dated as of June 15, 2015, as amended by that certain Amendment No. 1 to Severance Agreement dated August 1, 2016 (as amended, the "Moxley Severance Agreement"), upon termination of Mr. Moxley’s employment by us within 12 months following a sale event (as defined in the Moxley Severance Agreement), termination without “cause” or by Mr. Moxley for “good reason,” Mr. Moxley is entitled to receive (i) base salary through the date of termination, (ii) an amount equal to two times his target annual bonus, (iii) an amount equal to two times his then-current annual base salary and (iv) an amount equal to the cost of COBRA coverage for 18 months after termination. Additionally, severance payments are conditioned upon the execution of a general release of claims and continued compliance with certain non-solicitation restrictions for twelve months following termination and certain confidentiality provisions.

A for “cause” termination would occur under Mr. Moxley’s severance agreement if Mr. Moxley (i) fails to satisfactorily perform his material duties or to devote his full time and effort to his position, (ii) violates any material company policy that remains un-remedied after reasonable notice to cure the violation, (iii) fails to follow lawful directives from the Chairman,

Table of contents

President and Chief Executive Officer, the board of directors of our General Partner or Mr. Moxley's direct supervisor, (iv) his negligence or material misconduct, (v) his dishonesty or fraud or (vi) any felony conviction.

A "good reason" termination would be permitted under Mr. Moxley's severance agreement if: (i) there is material change in Mr. Moxley's job duties and responsibilities, (ii) a material diminution of his base salary unless the reduction applies to all employees of the General Partner employed at similar levels or (iii) a change in the location that Mr. Moxley regularly works of more than 25 miles.

With regard to Mr. Moxley's LTIP phantom unit awards, upon certain transactions generally resulting in a change in control of our General Partner or Partnership or cessation of his services due to death or disability, any unvested phantom units will vest in full. For additional information regarding the vesting of the phantom units, see the discussion under the Summary Compensation Table above.

With regard to Mr. Moxley's 2016 Cash LTIP Award, if Mr. Moxley is terminated without cause (as defined in the LTIP), then Mr. Moxley is entitled to receive the portion of the 2016 Cash LTIP Award that would have been payable on the next vesting date, but shall forfeit any further unvested 2016 Cash LTIP Award. A 2016 Cash LTIP Award shall vest in full, subject to continued employment through the certain event, upon a termination due to death or disability (as defined in the LTIP) or a change of control (as defined in the 2016 Cash LTIP). For additional information regarding the vesting of Mr. Moxley's 2015 Cash LTIP Award, see the discussion under the Summary Compensation Table above.

Mr. Allan's Severance and Change in Control Benefits. Mr. Allan's Severance Agreement, dated as of June 8, 2015, as amended by that certain Amendment No. 1 to Severance Agreement dated August 1, 2016, has the same terms as Mr. Moxley's Severance Agreement, described above.

Mr. Allan also has the same vesting as Mr. Moxley and Mr. Bonn with respect to his LTIP phantom unit awards and 2016 Cash LTIP Awards.

Mr. Williamson's Severance and Change in Control Benefits.

On January 6, 2017, our General Partner entered into an employment agreement with Mr. Williamson, the Chairman, President and Chief Executive of our General Partner (the "Williamson Employment Agreement"), which provides for an initial one year term, unless earlier terminated, that automatically extends for one year periods unless notice is given otherwise prior to the expiration of the then-current term. Mr. Williamson will receive an annualized base salary of $1,000,000 and will not be eligible for any annual incentive bonus. Mr. Williamson is entitled to receive certain benefits and reimbursement of certain expenses.

Under the Williamson Employment Agreement, upon a termination of Mr. Williamson's employment by us for any reason, Mr. Williamson is entitled to receive (i) any portion of his Annual Base Salary through the date of termination not theretofore paid, (ii) any expenses owed and (iii) any accrued and unused PTO owed. Upon termination of Mr. Williamson's employment by us without cause or by Mr. Williamson for good reason, then Mr. Williamson will also receive the remainder of his Annual Base Salary for the then current term, in addition to other payments and benefits described in the Williamson Employment Agreement. If the termination by us without cause or by Mr. Williamson for good reason occurs following a change in control (as defined in the Williamson Employment Agreement), the severance payment will be the annual base salary through the first anniversary of the date of termination. Additionally, the severance payment is conditioned upon the execution of a general release of claims and continued compliance with certain non-competition and non-solicitation restrictions for twelve months following termination and certain confidentiality provisions.

A for "cause" termination would occur under the Williamson Employment Agreement if Mr. Williamson (i) willfully fails to perform satisfactorily his lawful material duties or to devote his full time and effort to his position, (ii) actually violates any material company policy that remains un-remedied after reasonable notice to cure the violation, (iii) fails to follow lawful and reasonable directives from the board of directors of our General Partner, (iv) commits gross negligence or material misconduct, (v) commits any intentional act of fraud, embezzlement, misappropriation, material misconduct, conversion of assets or breach of fiduciary duty or (vi) any felony conviction.

A "good reason" termination would be permitted under the Williamson Employment Agreement within 90 days after the following occurs (without Mr. Williamson's written consent): (i) Mr. Williamson is removed as Chief Executive Officer or as a member of the Board, (ii) a material diminution of his base salary or (iii) a change in the location of

Mr. Williamson's employment to a location more than 50 miles from Dallas or Houston, Texas.
During his employment and for one year following his termination, Mr. Williamson is subject to certain non-competition and non-solicitation provisions set forth in the Williamson Employment Agreement. Mr. Williamson is also subject to certain confidentiality provisions during and after his employment.

Table of contents

Director Compensation

Officers, employees or paid consultants of our General Partner who also serve as directors do not receive additional compensation for their service as directors. As of January 6, 2017, Mr. Biegler is no longer an employee director and will receive compensation as a non-employee director in 2017. Effective as of January 6, 2017, Mr. Williamson became an officer of our General Partner and will not receive compensation as a director in 2017.

On April 12, 2016, the board of directors of our General Partner and our Compensation Committee revised our Southcross Energy Partners GP, LLC Non-Employee Director Compensation Arrangement. In 2015, our directors who were not officers, employees or paid consultants of our General Partner received a combination of cash and common units to be granted pursuant to the LTIP as compensation for attending meetings of our board of directors of our General Partner and any committees thereof. In 2016, our directors who were not officers, employees or paid consultants of our General Partner were awarded only cash compensation.

For 2016, our General Partner awarded $75,000 in cash to the directors who were not officers, employees or paid consultants of our General Partner. Such directors were not awarded an equity grant.

Specifically, directors were also eligible for the following in 2016:

i. An annual retainer of $50,000, to be paid quarterly in arrears;

ii. An annual retainer of $10,000 for the Chairperson of the Audit Committee, to be paid quarterly in arrears;

iii. An annual retainer of $5,000 for the Chairperson of the Compensation Committee, to be paid quarterly in arrears;

iv. An annual retainer of $2,500 for the Chairperson of the Conflicts Committee, to be paid quarterly in arrears;

v. $1,500 for each board meeting attended (whether in person or telephonically);

vi. $1,200 for each committee (Audit, Compensation or Conflicts) meeting attended (whether attended in person or telephonically); and

vii. A per diem amount for assistance with special projects, in an amount commensurate with the amount payable for attendance at Board or Committee meetings.

On December 15, 2016, the board of directors of our General Partner and the Compensation Committee further revised our Southcross Energy Partners GP, LLC Non-Employee Director Compensation Arrangement. In 2017, our directors who are not officers, employees or paid consultants of our General Partner will only be awarded cash compensation. For 2017, our General Partner awarded $75,000 in cash to the directors who are not officers, employees or paid consultants of our General Partner. Such directors were not awarded an equity grant.

Specifically, directors are also eligible for the following in 2017:

i. An annual retainer of $65,000, to be paid quarterly in February, April, July and October;

ii. An annual retainer of $15,000 for the Chairperson of the Audit Committee, to be paid quarterly in February, April, July and October;

iii. An annual retainer of $5,000 for the Chairperson of the Compensation Committee, to be paid quarterly in February, April, July and October;

iv. An annual retainer of $7,500 for the Chairperson of the Conflicts Committee, to be paid quarterly in February, April, July and October;

v. An annual retainer of $5,000 for each Independent Director for each committee in which they are a member (in addition to any fees they receive as a Chairperson), to be paid quarterly in February, April, July and October; and

vii. A per diem amount for assistance with special projects, in an amount commensurate with the amount payable for attendance at Board or Committee meetings.

Pursuant to the Non-Employee Director Compensation Arrangement, compensation for directors who serve for only a portion of a year is pro-rated for time served. Our non-employee directors are reimbursed for certain expenses incurred for their services to us.

We previously adopted the Southcross Energy Partners, L.P. Non-Employee Director Deferred Compensation Plan, pursuant to which non-employee directors of our general partner could elect on an annual basis to defer all earned cash and/or

Table of contents

equity compensation until the director is no longer a director of our general partner. All amounts deferred will be converted into phantom units from us, which will be entitled to receive quarterly distributions from us (to the extent declared). These quarterly distributions will also be converted to phantom units. At the conclusion of the deferral period, the accrued phantom units will be paid to the director in the form of (i) cash for deferrals of cash compensation equal to the fair market value as of such date and (ii) common units for deferrals of equity compensation. For the calendar year 2016, Mr. Williamson has elected to defer his non-employee director compensation. For the calendar year 2017, the Board authorized and approved the cessation of future deferral elections starting with the fees payable in 2017.

Mr. Biotti informed us that in accordance with the internal policies of Charlesbank Capital Partners, LLC ("Charlesbank"), a former sponsor, and the terms of the limited partnership agreements for the Charlesbank funds that have invested in Southcross Energy LLC, that all compensation otherwise payable to Mr. Biotti as a result of being a director of our General Partner should be paid as follows: (i) cash compensation should be paid directly to Charlesbank and (ii) in lieu of equity compensation, any such additional compensation should be paid in cash directly to Charlesbank. On April 13, 2016, Mr. Biotti resigned from the board of directors of our General Partner.

Mr. Downie informed us that in accordance with the internal policies of Tailwater and the terms of the limited partnership agreements for the Tailwater funds, all cash compensation otherwise payable to Mr. Downie as a result of being a director of our General Partner should be paid as follows: (i) cash compensation should be paid directly to Tailwater and (ii) in lieu of equity compensation, any such additional compensation should be paid in cash directly to Tailwater.

Mr. Henderson also informed us that in accordance with the internal policies of EIG and the terms of the limited partnership agreements for the EIG funds, that all compensation otherwise payable to Mr. Henderson as a result of being a director of our General Partner should be paid as follows: (i) cash compensation should be paid directly to EIG and (ii) in lieu of equity compensation, any such additional compensation should be paid directly to EIG.

Director Compensation for 2016

The following table presents the cash, equity awards and other compensation earned, paid or awarded to each of our non-employee directors during the year ended December 31, 2016:

Name	Fees earned or paid in cash(1)	Cash awards	Total
Jon M. Biotti (2)	$38,350	$—	$38,350
Jason Downie (3)	$85,300	$75,000	$160,300
Wallace C. Henderson (4)	$78,500	$75,000	$153,500
Nicholas J. Caruso	$124,000	$75,000	$199,000
Jerry W. Pinkerton	$126,500	$75,000	$201,500
Ronald G. Steinhart (5)	$74,967	$75,000	$149,967
Bruce A. Williamson	$115,000	$75,000	$190,000

(1) For Messrs. Caruso and Williamson, fees also include a $20,000 fee for Board projects in 2016. For Mr. Pinkerton, fees include a $10,000 fee in connection with Board projects in 2016.
(2) Director associated with Charlesbank. Cash compensation was paid in cash to Charlesbank. Mr. Biotti resigned on April 13, 2016.
(3) Director associated with Tailwater. Cash compensation was paid to Tailwater.
(4) Director associated with EIG. Cash compensation was paid to EIG.
(5) Mr. Steinhart resigned on October 24, 2016.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth certain information regarding the beneficial ownership of our units as of March 1, 2017 by:

- each person known to us to own beneficially 5% or more of any class of our outstanding units (including any "group" as that term is used in Section 13(d)(3) of the Exchange Act);

Table of contents

- each of the directors and named executive officers of our General Partner; and
- all of the directors and executive officers of our General Partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders, as the case may be, or based on a review of the copies of reports furnished to us.

Our General Partner is indirectly owned 100% by Holdings. EIG and Tailwater each indirectly own approximately one-third of Holdings, and a group of consolidated lenders under Holdings' revolving credit facility and term loan own the remaining one-third of Holdings. The general partner of Holdings is Southcross Holdings GP LLC ("Holdings GP"), of which EIG and Tailwater each indirectly own approximately one-third, and a group of consolidated lenders under Holdings' revolving credit facility and term loan own the remaining one-third of Holdings GP. Our General Partner owns all of the general partner interests in us.

The amounts and percentage of units beneficially owned are reported on the basis of SEC regulations governing the determination of beneficial ownership of securities. Under the SEC regulations, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote, or to direct the voting, of such security, and/or "investment power," which includes the power to dispose, or to direct the disposition of, such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, a right to acquire beneficial ownership of a security within 60 days of March 1, 2017 by a person, if any, are deemed to be outstanding for computing the percentage of outstanding securities of the class by such person, but are not deemed to be outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting power and sole investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

The percentages of units beneficially owned are based on a total of 48,516,567 common units, 12,213,713 subordinated units and 17,405,250 Class B Convertible Units outstanding as of March 1, 2017.

Name and address of beneficial owner(1)	Common units beneficially owned	Percentage of common units beneficially owned		Subordinated units beneficially owned(1)	Percentage of subordinated units beneficially owned		Class B Convertible Units beneficially owned(1)	Percentage of Class B Convertible Units beneficially owned		Percentage of total common, subordinated and Class B Convertible Units beneficially owned	
Our Holding Company:											
Southcross Holdings LP(2)(3)(4)	26,492,074	54.6	%	12,213,713	100.0	%	17,405,250	100	%	71.8	%
5% Owners Not Listed Above or Below:											
EIG BBTS Holdings, LLC(5)	26,492,074	54.6	%	12,213,713	100.0	%	17,405,250	100	%	71.8	%
TW Southcross Aggregator LP(6)	26,492,074	54.6	%	12,213,713	100.0	%	17,405,250	100	%	71.8	%
Directors and Named Executive Officers of Our General Partner:											
Bret M. Allan (2)	8,718	*		—	—		—	—		*	
David W. Biegler(2)	105,921	*		—	—		—	—		*	
John E. Bonn(2)	71,679	*		—	—		—	—		*	
Andrew A. Cameron(2)	—	—		—	—		—	—		—	
Nicholas J. Caruso, Jr.(2)	6,454	*		—	—		—	—		*	
Jason H. Downie(6)(7)	26,492,074	54.6	%	12,213,713	100.0	%	17,405,250	100	%	71.8	%
Wallace C. Henderson(8)	—	—		—	—		—	—		—	
Joel D. Moxley(2)	9,397	*		—	—		—	—		*	

Jerry W. Pinkerton(2)	14,739	*		—	—		—	—		*	
Bruce A. Williamson(2)(9)	12,739	*		—	—		—	—		*	
All current directors and executive officers of our General Partner as a group (consisting of 10 persons)(6)(8)(9)(10)	26,657,912	54.9	%	12,213,713	100.0	%	17,405,250	100	%	72.0	%

* An asterisk indicates that the person or entity owns less than one percent.

(1) This beneficial ownership table was prepared as of March 1, 2017. The subordinated units convert into common units on a one-for-one basis on the expiration of the Subordination Period (as defined in the Partnership Agreement). The Class B Convertible Units convert into common units at the Class B Conversion Rate (as defined in our Partnership Agreement) on the Class B Conversion Date (as defined in the Partnership Agreement). Because such subordinated units and Class B Convertible Units were acquired in connection with transactions having the purpose or effect of changing or influencing the control of us, such subordinated units and Class B Convertible Units are considered converted for purposes of the calculations of the amounts noted under Rule 13d-3(d)(1)(i) of the Exchange Act. Pursuant to Rule 13d-3(d)(1)(i), the subordinated units and Class

114

Table of contents

B Convertible Units are deemed outstanding for computing the percentage of the class owned by such beneficial owner, but not deemed to be outstanding for the purpose of computing the percentage of the class for any other person. The beneficial ownership reported for the Class B Convertible Units includes additional Class B Convertible Units issued in kind as distributions.

(2) The address for this person or entity is 1717 Main Street, Suite 5200, Dallas, Texas 75201.

(3) Holdings, through its wholly-owned subsidiaries, owns 100% of our General Partner, 26,492,074 of our common units, 12,213,713 of our subordinated units and 17,405,250 of our Class B Convertible Units.

(4) Based on a Schedule 13D/A filed with the SEC on January 12, 2017 and a Form 4 filed with the SEC on February 15, 2017. The filing was made jointly by Southcross Holdings LP, Southcross Holdings GP LLC, Southcross Holdings Intermediary LLC, Southcross Holdings Guarantor GP LLC, Southcross Holdings Guarantor LP, Southcross Holdings Borrower GP LLC and Southcross Holdings Borrower LP. Each party to the Schedule 13D, as amended, shares voting and dispositive power. The address for each party to the Schedule 13D, as amended, is 1717 Main Street, Suite 5200, Dallas, Texas 75201.

(5) Based on a Schedule 13D/A filed with the SEC on January 13, 2017 and a Form 4 filed with the SEC on February 14, 2017. The filing was made jointly by EIG BBTS Holdings, LLC, EIG Management Company, LLC, EIG Asset Management, LLC, EIG Global Energy Partners, LLC, The R. Blair Thomas 2010 Irrevocable Trust, R. Blair Thomas, The Randall Wade 2010 Irrevocable Trust, The Kristina Wade 2010 Irrevocable Trust and Randall S. Wade. Each party to the Schedule 13D shares voting and dispositive power. The address for each party to the Schedule 13D is 1700 Pennsylvania Ave. NW, Suite 800, Washington, D.C. 20006.

(6) Based on a Schedule 13D/A filed with the SEC on January 13, 2017 and a Form 4 filed with the SEC on February 14, 2017. The filing was made jointly by TW Southcross Aggregator LP, TW/LM GP Sub, LLC, Tailwater Energy Fund I LP, TW GP EF-I, LP, TW GP EF-I GP, LLC, TW GP Holdings, LLC, Tailwater Holdings, LP, Tailwater Capital LLC, Jason H. Downie and Edward Herring. Each party to the Schedule 13D, as amended, shares voting and dispositive power. Based on the relationship of Jason H. Downie to Southcross Holdings Borrower LP, Downie, a director of our General Partner, may be deemed to indirectly beneficially own the common units, subordinated units and Class B Convertible Units held by Southcross Holdings Borrower LP. The address for each party to the Schedule 13D, as amended, is 2021 McKinney Avenue, Suite 1250, Dallas, Texas 75201.

(7) Mr. Downie owns no units directly. Includes 26,492,074 common units, 12,213,713 subordinated units and 17,405,250 Class B Convertible Units indirectly owned by Holdings. Based on the relationship of Mr. Downie to Southcross Holdings Borrower LP, Mr. Downie may be deemed to indirectly beneficially own the common units, subordinated units and Class B Convertible Units held by Southcross Holdings Borrower LP. Mr. Downie disclaims beneficial ownership of the securities reported, except to the extent of Mr. Downie’s indirect pecuniary interest.

(8) The address for Mr. Henderson is 1700 Pennsylvania Ave. NW, Suite 800, Washington, D.C. 20006.

(9) Represents phantom units issued under the Non-Employee Director Deferred Compensation Plan whereby Mr. Williamson has the right to acquire common units within 30 days of termination of his services. Mr. Williamson has elected to defer all earned compensation under the Non-Employee Director Deferred Compensation Plan until he is no longer a director of our General Partner. In accordance with the Non-Employee Director Deferred Compensation Plan, Mr. Williamson has a total of 157,978 phantom units, 145,239 of which will be settled in cash equal to the fair market value of our common units on the date of termination of Mr. Williamson’s services (and which are not included in the table).

(10) Does not include any unvested phantom units granted to such directors and executive officers under the LTIP.

Holdings has pledged the common units, subordinated units, and Class B Convertible Units that it owns as security under Holding’s credit facilities. These credit facilities include customary provisions regarding potential events of default. Therefore, if an event of default occurred under Holding’s credit facilities, a change in ownership of the units owned by Holdings could occur.

Securities Authorized for Issuance Under Equity Compensation Plan(1)

We have one compensation plan under which our common units are authorized for issuance, the LTIP. This equity compensation plan was approved by our unitholders. The following table sets forth certain information relating to the LTIP as of December 31, 2016:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by securities holders	368,281	—	5,171,916
Equity compensation plans not approved by security holders	—	—	—
Total	368,281	$ —	5,171,916

(1) See Note 11 to our consolidated financial statements for more information. No value is shown in column (b) of the table because the phantom units do not have an exercise price.

115

Table of contents

Item 13. Certain Relationships and Related Transactions, and Director Independence

As of March 1, 2017, Holdings owns 26,492,074 common units, 12,213,713 subordinated units and 17,405,250 Class B Convertible Units, representing a combined 71.8% limited partner interest in us. In addition, Holdings owns and controls our General Partner, which owns a 2.0% General Partner interest in us and all of our incentive distribution rights. Our General Partner owns all of the general partner interests in us. EIG and Tailwater each indirectly own approximately one-third of Holdings, and a group of consolidated lenders under Holdings' revolving credit facility and term loan (the "Lenders") own the remaining one-third of Holdings. The general partner of Holdings is Southcross Holdings GP LLC ("Holdings GP"), of which EIG and Tailwater each indirectly own approximately one-third, and the Lenders own the remaining one-third of Holdings GP.

Our common units represent limited partner interests in us. The holders of our common units are entitled to participate in our distributions (to the extent distributions are declared) and are entitled to exercise the rights and privileges available to limited partners under our Partnership Agreement. In accordance with the requirements of the Equity Cure Agreement, Holdings was issued 8,029,729 common units on May 2, 2016 and 359,459 common units on May 13, 2016.

Pursuant to the Equity Cure Contribution Amendment, Holdings contributed $17.0 million to the Partnership in exchange for 11,486,486 common units on December 29, 2016. The proceeds of the $17.0 million contribution were used to pay down the outstanding balance under the Third A&R Revolving Credit Agreement and for general corporate purposes.

The following table summarizes the distributions and payments owed by us to our General Partner and its affiliates in connection with our ongoing operations and liquidation. Certain of these distributions and payments were determined among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage	
Distributions to our General Partner and its affiliates	Previously, we generally made cash distributions (except with respect to our Class B Convertible Units, which are paid in Class B PIK Units) of 98.0% to our unitholders pro rata (including to Holdings, as the holder of a 61.5% limited partnership interest in us) and 2.0% to our General Partner, assuming our General Partner makes any capital contributions necessary to maintain its 2.0% general partner interest in us. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, our General Partner is entitled to increasing percentages of the distributions, up to 48.0% of the distributions above the highest target distribution level in connection with its incentive distribution rights. The board of directors of our General Partner suspended paying a quarterly distribution with respect to the fourth quarter of 2015 and every quarter of 2016 to reserve any excess cash for the operation of our business. The board of directors of our General Partner and our management believe this suspension to be in the best interest of our unitholders and will continue to evaluate our ability to reinstate the distribution in future periods. Additionally, we are restricted under the Fifth Amendment on paying a distribution until our Consolidated Total Leverage Ratio is below 5.0. See Notes 2 and 4 to our consolidated financial statements.
Payments to our General Partner and its affiliates	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 reimbursement for all expenses incurred on our behalf, including, among other items, compensation expense for all employees required to manage and operate our business. Our Partnership Agreement provides that our General Partner will determine the amount of these reimbursed expenses. In addition, as described below, these employees provide services to affiliated entities, including Holdings, and the expenses for these services are allocated by the board of directors of our General Partner.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case, for an amount equal to the fair market value of those interests.

Liquidation Stage	
Liquidation	Upon our liquidation, our partners, including our General Partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

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. During the year ended December 31, 2016, we incurred expenses related to these reimbursements, which are reflected in operating expenses in our consolidated statements of operations.

Table of contents

Holdings Chapter 11 Reorganization

On March 28, 2016, Holdings and certain of its subsidiaries (excluding us, our General Partner and our subsidiaries) filed a pre-packaged plan of reorganization (the “POR”) under Chapter 11 of the U.S. Bankruptcy Code in the Southern District of Texas to restructure its debt obligations and strengthen its balance sheet. Our operations, customers, suppliers, partners and other constituents were excluded from such proceeding. On April 11, 2016, the bankruptcy court confirmed Holdings’ POR, and on April 13, 2016, Holdings and its subsidiaries emerged from bankruptcy with its Lenders being issued 33.34% of the limited partner interests in Holdings in exchange for the elimination of certain funded debt obligations. EIG and Tailwater each contributed $85 million in cash (or $170 million in the aggregate) in exchange for each Sponsor receiving 33.33% of the limited partner interests in Holdings. In addition, Holdings committed to provide us $50 million (as part of the Equity Cure Agreement defined below), out of the $170 million in new equity contributed to Holdings from the Sponsors, to provide us with liquidity to comply with the applicable financial covenants set forth in our credit agreement at the time.

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, 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. Due to the common control aspects in the 2015 Holdings Acquisition, the Partnership’s financial results retrospectively include the financial results for the Valley Wells System and the Compression Assets for all periods ending after August 4, 2014, the date of the Holdings Transaction. For additional details regarding the 2015 Holdings Acquisition, see Notes 1 and 3 to our consolidated financial statements.

Holdings Equity Cure Contribution Agreement, Investment Agreement, Backstop Agreement, and Equity Cure Contribution Amendment

In accordance with the requirements of the Equity Cure Agreement, Holdings was issued 8,029,729 common units on May 2, 2016 and 359,459 common units on May 13, 2016. See Notes 2 and 7 to the consolidated financial statements for additional details.

Pursuant to the Equity Cure Contribution Amendment, Holdings contributed $17.0 million to the Partnership in exchange for 11,486,486 common units on December 29, 2016. The proceeds of the $17.0 million contribution were used to pay down the outstanding balance under the Third A&R Revolving Credit Agreement and for general corporate purposes. See Notes 2 and 7 to the consolidated financial statements for additional details.

In connection with the execution of the Fifth Amendment, on December 29, 2016, the Partnership entered into (i) the Investment Agreement with Holdings and Wells Fargo Bank, N.A., (ii) the Backstop Agreement with Holdings, Wells Fargo Bank, N.A. and the Sponsors and (iii) the Equity Cure Contribution Amendment with Holdings. See Notes 2 and 7 to the consolidated financial statements for additional details.

Recent Lack of Quarterly Distributions

The board of directors of our General Partner suspended paying a quarterly distribution with respect to the fourth quarter of 2015 and every quarter of 2016 to reserve any excess cash for the operation of our business. The board of directors of our General Partner and our management believe this suspension to be in the best interest of our unitholders and will continue to evaluate our ability to reinstate the distribution in future periods. Additionally, we are restricted under the fifth amendment to the Third A&R Revolving Credit Agreement from paying a distribution until our Consolidated Total Leverage Ratio is below 5.0.

Board of Directors

The board of directors of our General Partner is comprised of seven directors. Pursuant to the organizational documents of the general partner of Holdings, two directors (one of whom must be independent) on our board of directors will be appointed by each of EIG, Tailwater and the group of lenders who received membership interest in Holdings in connection with Holdings' Chapter 11 reorganization. Bruce Williamson serves as chairman of the board as of January 6, 2017. David W. Biegler remains as one of the directors of our General Partner.

All of our non-employee directors are compensated equally for similar responsibilities and reimbursed for expenses incurred for their services to us. For the years ended December 31, 2016 and 2015, we paid Charlesbank, EIG and Tailwater

---

Table of contents

$0.2 million and $0.3 million, respectively, for director fees and related expenses. These expenses are reflected in general and administrative expenses in our consolidated statements of operations.

Shared Services with Southcross Holdings LP and Other Affiliates

Certain of the employees of our General Partner perform management, administrative, operational and workforce related services to affiliated entities, including Holdings, which owns 100% of our General Partner, and an affiliate that is partially owned by EIG and Tailwater, two of our Sponsors. The expenses associated with these services, which are shared with these entities, are recorded in general and administrative expense in our statement of operations and are allocated in a manner approved by the board of directors and Conflicts Committee. For the years ended December 31, 2016 and 2015, we allocated $1.4 million and $3.4 million, respectively, to Holdings.

The Conflicts Committee of the board of directors of our General Partner has reviewed the cost allocation methodology applicable to these services and, based on representations from management, determined that the fees charged were fair.

Other Transactions with Affiliates

On March 17, 2016, our General Partner entered into retention agreements with certain executives of our General Partner, pursuant to which the executives received a one-time special restructuring bonus in an amount equal to 100% of then-current annual salary for remaining employed with our General Partner through the date of Holdings' emergence from bankruptcy. The bonuses of $1.5 million were paid by Holdings on April 22, 2016.

In addition, on November 3, 2016, each of these executives of our General Partner received a one-time retention bonus in an amount equal to 100% of then-current annual salary for remaining employed with our General Partner through November 1, 2016. The bonuses of $1.5 million were paid by Holdings.

On January 7, 2016, in response to our need for additional liquidity, we issued at par Senior Unsecured PIK Notes in the aggregate principal amount of $14 million (the "PIK Notes") to affiliates of EIG and Tailwater, with interest at a rate of 7% due January 7, 2017. Contemporaneous with the resolution of Holdings' bankruptcy proceedings in April 2016, the PIK Notes and the related PIK interest of $0.3 million were repaid in full.

We have 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 commercial agreements, we transport, process and sell rich natural gas for the affiliate of Holdings in return for agreed-upon fixed fees, and we can sell natural gas liquids that we own to Holdings at agreed-upon fixed prices. The NGL Agreement also permits us to utilize Holdings' fractionation services at market-based rates.

We have 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 was capped at $1.7 million per quarter through December 31, 2016. In the first and second quarters of 2016, we exceeded this cap by $1.0 million and $1.4 million, respectively. We did not exceed this cap in the third or fourth quarter of 2016.

We recorded revenues from affiliates of $97.5 million and $94.7 million for the years ended December 31, 2016 and 2015, respectively, in accordance with the G&P Agreement, the NGL Agreement and the series of commercial agreements.

We had accounts receivable due from affiliates of $8.0 million and $49.7 million as of December 31, 2016 and 2015, respectively, and accounts payable due to affiliates of $50.6 million and $66.5 million as of December 31, 2016 and

2015, respectively. The affiliate receivable and payable balances are related primarily to transactions associated with Holdings, noted above, and our joint venture investments. See Note 13 to our consolidated financial statements. The receivable balance due from Holdings is current as of December 31, 2016.

During the year ended December 31, 2015, Holdings purchased $2.3 million of office leasehold improvements from SXE.

Procedures for Review, Approval and Ratification of Related-Person Transactions

We have a Code of Business Conduct and Ethics that requires the board of directors of our General Partner or its Conflicts Committee to review periodically all related-person transactions that are required to be disclosed under SEC rules and, when appropriate, to authorize or ratify all such transactions. If the board of directors of our General Partner or its Conflicts

Table of contents

Committee considers ratification of a related-person transaction and determines not to so ratify, the Code of Business Conduct and Ethics provides that our management will make all reasonable efforts to cancel or annul the transaction. Our Code of Business Conduct and Ethics provides that, in determining whether to recommend the initial approval or ratification of a related-person transaction, the board of directors of our General Partner or its Conflicts Committee should consider all of the relevant facts and circumstances available, including (if applicable), but not limited to: (i) whether there is an appropriate business justification for the transaction, (ii) the benefits that accrue to us as a result of the transaction, (iii) the terms available to unrelated third parties entering into similar transactions, (iv) the impact of the transaction on director independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediately family member of a director is a partner, shareholder, member or executive officer), (v) the availability of other sources for comparable products or services, (vi) whether it is a single transaction or a series of ongoing, related transactions, and (vii) whether entering into the transaction would be consistent with our Code of Business Conduct and Ethics.

See Part II, Item 10 of this report for a discussion regarding director independence.

Item 14. Principal Accountant Fees and Services

We have engaged Deloitte & Touche LLP as our independent registered public accounting firm. The following table summarizes fees we have paid Deloitte & Touche LLP for the audit of our annual financial statements and other services rendered for the years ended December 31, 2016 and 2015:

	Year ended December 31, 2016	2015
Audit fees[1]	$1,453,000	$1,357,900
Audit-related fees[2]	110,500	300,000
Tax fees[3]	30,003	48,882
	$1,593,503	$1,706,782

(1) The Audit fees are fees billed for professional services for the audit and quarterly reviews of the Partnership's consolidated financial statements, review of other SEC filings, including registration statements, and issuance of comfort letters and consents.

(2) Audit-related fees are fees billed for assurance and related services related to consultations and audits performed in connection with acquisitions, and assistance with the implementation of Section 404 of the Sarbanes-Oxley Act.

(3) Tax fees are billed for sales tax planning and advisory services.

Audit Committee Approval of Audit and Non-Audit Services

The Audit Committee of the board of directors of our General Partner has adopted a policy with respect to services which may be performed by Deloitte & Touche LLP. This policy lists specific audit-related and tax services as well as any other services that Deloitte & Touche LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional Audit Committee authorization. The Audit Committee receives quarterly reports on the status of expenditures pursuant to that policy. The Audit Committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the Audit Committee or by its chairman, to whom such authority has been conditionally delegated, prior to engagement.

The Audit Committee has approved the appointment of Deloitte & Touche LLP as independent registered public accounting firm to conduct the audit of our financial statements for the year ended December 31, 2016.

Table of contents

Item 15. Exhibits and Financial Schedules

(a) Financial Statements

(1) Included in Part II, Item 8 of this report.

(2) All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibit Index.

An "Exhibit Index" has been filed as part of this report beginning in sub-item (b) below of this item and is incorporated herein by reference.

Schedules other than those listed above are omitted because they are not required, not material, not applicable or the required information is shown in the financial statements or notes thereto.

Agreements attached or incorporated herein as exhibits to this report are included to provide investors with information regarding the terms and conditions of such agreements and are not intended to provide any other factual or disclosure information about the Partnership or the other parties to the agreements.

Such agreements may contain representations and warranties by the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (i) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate, (ii) have been qualified by disclosures that were made to the other party or parties in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement, (iii) may apply standards of materiality in a way that is different from what may be viewed as material to you or other investors and (iv) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, the representations and warranties in such agreements may not describe the actual state of affairs as of the date they were made or at any other time.

(b) Exhibits and Exhibit Index

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 the 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).
10.1	Third Amended and Restated Revolving Credit Agreement, dated as of August 4, 2014, by and among Southcross Energy Partners, L.P., 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 the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated August 4, 2014).

Table of contents

Exhibit Number	Description
10.2	First Amendment to Third Amended and Restated Revolving Credit Agreement, by and among the Partnership, as borrower, Wells Fargo Bank, N.A., as Administrative Agent, and the lenders and other parties thereto, dated as of May 7, 2015 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K dated May 7, 2015).
10.3	Limited Waiver and Second Amendment to Third Amended and Restated Revolving Credit Agreement, by and among the Partnership, as borrower, Wells Fargo Bank, N.A., as Administrative Agent, and the lenders and other parties thereto, dated as of August 4, 2016 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2016).
10.4	Waiver and Third Amendment to Third Amended and Restated Revolving Credit Agreement, by and among the Partnership, as borrower, Wells Fargo Bank, N.A., as Administrative Agent, and the lenders and other parties thereto, dated as of November 8, 2016 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2016).
10.5	Waiver and Fourth Amendment to Third Amended and Restated Revolving Credit Agreement, by and among the Partnership, as borrower, Wells Fargo Bank, N.A., as Administrative Agent, and the lenders and other parties thereto, dated as of December 9, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated December 12, 2016).
10.6	Waiver and Fifth Amendment to Third Amended and Restated Revolving Credit Agreement, by and among the Partnership, as borrower, Wells Fargo Bank, N.A., as Administrative Agent, and the lenders and other parties thereto, dated as of December 29, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated January 3, 2017).
10.7	Term Loan Credit Agreement, dated as of August 4, 2014, by and among Southcross Energy Partners, L.P., Wilmington Trust, National Association (successor to Wells Fargo Bank, N.A.), as Administrative Agent, UBS Securities LLC and Barclays Bank PLC, as Co-Syndication Agents, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K dated August 4, 2014).
10.8#	Southcross Energy Partners, L.P. Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated December 8, 2015).
10.9#	Form of Phantom Unit Award Agreement (incorporated by reference to Exhibit 10.5 to the Registration Statement on Form S-1 (Commission File No. 333-180841)).
10.10#	Southcross Energy Partners GP, LLC and Southcross GP Management Holdings, LLC 2014 Equity Incentive Plan and Form of Unit Award Agreement (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K dated August 4, 2014).
10.11#	Southcross Energy Partners GP, LLC Non-Employee Director Compensation Arrangement (incorporated by reference to Exhibit 10.12 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2012).
10.12#	Southcross Energy Partners, L.P. Non-Employee Director Deferred Compensation Plan (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2012).
10.13	Contribution Agreement, dated as of June 11, 2014, by and among TexStar Midstream Services, LP, Southcross Energy Partners, L.P. and Southcross Energy GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated June 11, 2014).
10.14#	Employment Agreement, dated as of March 5, 2015, by and between Southcross Energy Partners GP, LLC and John E. Bonn (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2015).
10.15	Purchase, Sale and Contribution Agreement, by and among Southcross Energy Partners, L.P., Southcross CCNG Gathering Ltd., Southcross NGL Pipeline Ltd., FL Rich Gas Services, LP, TexStar Midstream Utility, LP, Frio LaSalle Pipeline, LP and Southcross Holdings LP, dated as of May 7, 2015 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated May 7, 2015).
10.16#	Severance Agreement, dated as of June 8, 2015, by and between Southcross Energy Partners GP, LLC and Bret M. Allan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated June 8,

	2015).
10.17#*	Amendment No. 1 to Severance Agreement, dated August 1, 2016, by and between Southcross Energy Partners GP, LLC and Bret M. Allan.
10.18#	Severance Agreement, dated as of June 15, 2015, by and between Southcross Energy Partners GP, LLC and Joel D. Moxley (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated June 15, 2015).
10.19#*	Amendment No. 1 to Severance Agreement, dated August 1, 2016, by and between Southcross Energy Partners GP, LLC and Joel D. Moxley.
10.20	Equity Cure Contribution Agreement, dated March 17, 2016, by and between Southcross Energy Partners, L.P. and Southcross Holdings LP (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated March 22, 2016).

Table of contents

Exhibit Number	Description
10.21	First Amendment to Equity Cure Contribution Agreement, dated December 29, 2016, by and between Southcross Energy Partners, L.P. and Southcross Holdings LP (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K dated December 29, 2016).
10.22	Investment Agreement, dated December 29, 2016, by and among Southcross Energy Partners, L.P., Southcross Holdings LP and Wells Fargo Bank, N.A. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K dated December 29, 2016).
10.23	Backstop Investment Commitment Letter, dated December 29, 2016, by and among Southcross Energy Partners, L.P., Southcross Holdings LP, Wells Fargo Bank, N.A. and the Sponsors party thereto (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K dated December 29, 2016).
10.24#	Southcross Energy Partners, L.P. 2016 Cash-Based Long-Term Incentive Plan dated March 11, 2016 and Form of Award Agreement (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K for the fiscal year ended December 31, 2015).
10.25#	Retention Agreement, dated March 17, 2016, by and between Southcross Energy Partners GP, LLC and Mr. John E. Bonn (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K dated March 17, 2016).
10.26#	Retention Agreement, dated March 17, 2016, by and between Southcross Energy Partners GP, LLC and Mr. Bret M. Allan (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K dated March 17, 2016).
10.27#	Retention Agreement, dated March 17, 2016, by and between Southcross Energy Partners GP, LLC and Mr. Joel D. Moxley (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K dated March 17, 2016).
10.28	Form of Senior Unsecured PIK Note, dated as of January 7, 2016, by and between Southcross Energy Partners, L.P. and the Lender party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated January 7, 2016).
10.29#	Employment Agreement, dated January 6, 2017, by and between Bruce A. Williamson and Southcross Energy Partners GP, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated January 6, 2017).
10.30#	Severance Agreement and General Release, dated February 21, 2017, by and between Southcross Energy Partners GP, LLC and John E. Bonn (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated February 21, 2017).
10.31#*	Southcross Energy Partners GP, LLC Non-Employee Director Compensation Arrangement, beginning January 1, 2017.
21.1*	List of Subsidiaries of Southcross Energy Partners, L.P.
23.1*	Consent of Deloitte & Touche LLP.
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

Management contracts or compensatory plans or arrangement.

* Filed or furnished herewith.

†

The financial information contained in the XBRL (eXtensible Business Reporting Language)-related documents is unaudited.

(c) Financial Statement Schedules

Not applicable.

Table of contents

SIGNATURES

Pursuant to the requirements of Section 13 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:	March 9, 2017	By: /s/ BRUCE A. WILLIAMSON
		Bruce A. Williamson
		President, Chief Executive Officer and Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the registrant and in the capacities and on the dates indicated have signed this report below.

SIGNATURE	TITLE	DATE
/s/ BRUCE A. WILLIAMSON Bruce A. Williamson	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 9, 2017
/s/ BRET M. ALLAN Bret M. Allan	Senior Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	March 9, 2017
/s/ DAVID W. BIEGLER David W. Biegler	Director	March 9, 2017
/s/ ANDREW A. CAMERON Andrew A. Cameron	Director	March 9, 2017
/s/ NICHOLAS J. CARUSO Nicholas J. Caruso	Director	March 9, 2017
/s/ JASON DOWNIE Jason Downie	Director	March 9, 2017
/s/ WALLACE HENDERSON Wallace Henderson	Director	March 9, 2017
/s/ JERRY W. PINKERTON Jerry W. Pinkerton	Director	March 9, 2017