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As filed with the Securities and Exchange Commission on July 13, 2012

Registration No. 333-180841

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 2

to

Form S-1

**REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933**

Southcross Energy Partners, L.P.

(Exact Name of Registrant as Specified in its Charter)

Delaware	**4922**	**45-5045230**
(State or Other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

1700 Pacific Avenue
Suite 2900
Dallas, Texas 75201
(214) 979-3700
(Address, including Zip Code, and Telephone Number, including Area Code, of Registrant's Principal Executive Offices)

David W. Biegler
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Approximate date of commencement of proposed sale to the public:
As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. o

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ý (Do not check if a smaller reporting company)	Smaller reporting company o

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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SUBJECT TO COMPLETION, DATED , 2012

PRELIMINARY PROSPECTUS

Common Units
Representing Limited Partner Interests
Southcross Energy Partners, L.P.

This is the initial public offering of our common units representing limited partner interests. We are offering common units in this offering. We currently expect that the initial public offering price will be between $ and $ per common unit. Prior to this offering, there has been no public market for our common units.

We have granted the underwriters an option to purchase up to additional common units. We intend to apply to list our common units on the New York Stock Exchange under the symbol "SXE."

Investing in our common units involves risks. Please read "Risk Factors" beginning on page 18.

These risks include the following:

- 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 holders of our common and subordinated units.

- Because of the natural decline in production from existing wells in our areas of operation, our success depends in part on producers 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 natural gas liquids, or NGLs, that we fractionate could adversely affect our business and operating results.

- Natural gas and NGL prices are volatile, and a change in these prices in absolute terms, or an adverse change in the prices of 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.

- Unplanned downtime associated with our assets or third-party assets interconnected with our assets could have a material adverse effect on our business and operating results.

Southcross Energy LLC, or Holdings, owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations and has limited duties to us and our unitholders. Holdings 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.

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. Following this offering, the market price of our common units may fluctuate significantly, and you could lose all or part of your investment.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

We are an emerging growth company and are eligible for reduced reporting requirements. See "Summary Implications of Being an Emerging Growth Company."

Neither the Securities and Exchange Commission nor any other regulatory body has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

	Per Common Unit	Total
Initial Public Offering Price	$	$
Underwriting Discounts and Commissions(1)	$	$
Proceeds to Southcross Energy Partners, L.P. (before expenses)	$	$

(1) Excludes an aggregate structuring fee payable to Citigroup Global Markets Inc. and Wells Fargo Securities, LLC that is equal to % of the gross proceeds of this offering. Please see "Underwriting." The structuring fee will be paid to Citigroup Global Markets Inc. and Wells Fargo Securities, LLC from the net proceeds of this offering. Please see "Use of Proceeds."

The underwriters expect to deliver the common units to purchasers on or about , 2012, through the book-entry facilities of The Depository Trust Company.

Joint Book-Running Managers

Citigroup **Wells Fargo Securities**

, 2012

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You should rely only on the information contained in this prospectus or in any free writing prospectus we may authorize to be delivered to you. Neither we nor the underwriters have authorized anyone to provide you with additional or different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where the offer or sale is not permitted. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front of this prospectus.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Although we believe these third-party sources are reliable and that the information is accurate and complete, we have not independently verified the information.

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SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the historical financial statements and related notes contained herein, before investing in our common units. The information presented in this prospectus assumes (1) an initial public offering price of $ per common unit (the midpoint of the price range set forth on the cover of this prospectus) and (2) unless otherwise indicated, that the underwriters' option to purchase additional common units is not exercised. You should read "Risk Factors" beginning on page 18 for more information about important risks that you should consider carefully before investing in our common units.

Unless the context otherwise requires, references in this prospectus to "Southcross Energy Partners, L.P.," the "partnership," "we," "our," "us" or like terms (i) for periods prior to August 1, 2009, the effective date of Southcross Energy LLC's acquisition of our initial assets from Crosstex Energy, L.P., or "Crosstex," refer to the entities and assets we acquired from Crosstex, which we refer to as the Southcross Energy Predecessor, or our "Predecessor," and (ii) for periods from and after August 1, 2009, refer to Southcross Energy Partners, L.P. and its subsidiaries after giving effect to the recapitalization transactions described under " Recapitalization Transactions and Partnership Structure" on page 7 of this prospectus. References to "Southcross Energy Partners GP" or our "general partner" refer to Southcross Energy Partners GP, LLC, a Delaware limited liability company and our general partner, references to "Charlesbank" refer to Charlesbank Capital Partners, LLC and its affiliated investment funds, and references to "Holdings" refer to Southcross Energy LLC, a Delaware limited liability company owned by Charlesbank and certain members of our management team. References to "EAI" refer to Enterprise Alabama Intrastate, LLC, an intrastate pipeline and gathering system in Alabama that we acquired from a subsidiary of Enterprise Products Partners L.P. effective September 1, 2011. We include as Appendix B a glossary of some of the terms we use in this prospectus.

Southcross Energy Partners, L.P.

Overview

We are a growth-oriented limited partnership that was formed by members of our management team and Charlesbank to own, operate, develop and acquire midstream energy assets. We provide natural gas gathering, processing, treating, compression and transportation services and natural gas liquids, or NGLs, fractionation services to our producer customers, primarily under fixed-fee and fixed-spread contracts, and we also source, purchase, transport and sell natural gas and NGLs to our power generation, industrial and utility customers. Our assets are located in South Texas, Mississippi and Alabama. Our South Texas assets operate in or within close proximity to the Eagle Ford shale region, which has experienced a strong increase in investment and drilling activity by exploration and production companies in recent years. Based on industry data compiled by Smith Bits, a subsidiary of Smith International, Inc., approximately 14.2% of all drilling rigs in the United States were operating in the Eagle Ford shale region as of May 25, 2012. We expect this heightened Eagle Ford shale activity, as well as activity in the frequently overlying Olmos tight sand formation, will result in higher throughput on our systems and opportunities to expand our asset base over the next several years. Our Mississippi and Alabama assets are strategically positioned to provide transportation of natural gas to our power generation, industrial and utility customers as well as to unaffiliated interstate pipelines. We expect to grow our business and distributable cash flow by expanding the capacity and efficiency of our assets and by making selective acquisitions, such as our acquisition of EAI in September 2011.

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Our assets, the majority of which we acquired from Crosstex in August 2009, consist of five gathering systems, two processing plants, two intrastate pipelines, one fractionator and ancillary assets. The following table provides information regarding our assets by operating region as of December 31, 2011.

Region	Asset/System Type	Length (Miles)	Compression (Horsepower)	Throughput Capacity (MMcf/d)	Fractionation Capacity (Bbls/d)
South Texas	Gathering pipelines	951	7,836	390	
	Intrastate pipeline	494	1,260	200	
	Processing facilities		26,670	185	
	Fractionation facilities				4,800
Mississippi/Alabama					
	Gathering pipelines	320	24,537	415	
	Intrastate pipeline	825	2,200	305	
Total					
	Gathering pipelines	1,271	32,373	805	
	Intrastate pipeline	1,319	3,460	505	
	Processing facilities		26,670	185	
	Fractionation facilities				4,800

We generate the majority of our gross operating margin from our business in South Texas. For the year ended December 31, 2011, we generated $523.1 million of revenue and $62.6 million of gross operating margin. In that time period, 75.0% of our gross operating margin was generated from fixed-fee and fixed-spread arrangements with respect to which we have little or no direct commodity price exposure. For a definition of gross operating margin and a reconciliation of gross operating margin to its most directly comparable financial measure calculated in accordance with GAAP, please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures."

Our Growth Drivers

We seek to identify and pursue economically attractive organic expansion and third-party acquisition opportunities that leverage our existing assets and enhance strategic relationships with our customers. We currently expect that opportunities in the Eagle Ford shale area will be a primary driver of our near-term growth due to the increased drilling activity and production of natural gas and NGLs in this area. From January 1, 2011 through June 30, 2012, we commenced or completed the major acquisitions and growth projects listed below involving estimated capital expenditures of $202.8 million, out of our total expansion capital expenditures of $227.5 million during the same period. Please read "Our Cash Distribution Policy and Restrictions on Distributions Estimated Cash Available for Distribution for the Twelve Months Ending June 30, 2013" for more information regarding our forecast of the estimated cash available for distribution we may realize from the projects set forth below.

- we have completed construction of and are commencing operations of a 200 MMcf/d cryogenic processing plant in Refugio County, Texas, which we refer to as our Woodsboro processing plant, to expand our South Texas processing capacity;

- we are expanding our NGL capacity by installing an 11,500 Bbl/d fractionation facility, which we refer to as our Bonnie View fractionation plant, and constructing associated pipelines in South Texas to transport fractionated NGLs to market;

- we reactivated an idle train at our Gregory processing plant in South Texas, upgraded existing equipment and added new equipment to increase the plant's processing capacity from 85 MMcf/d to 135 MMcf/d while improving recoveries of NGLs from the plant;

- we acquired lateral pipelines near our Gregory processing plant in South Texas that enhance the delivery capacity of our Gregory system and serve as additional gas residue pipelines for our processing plants;
- we acquired EAI, an intrastate natural gas pipeline system and gathering system in northwest and central Alabama that averaged approximately 107 MMcf/d of throughput volume during the last four months of 2011;
- we constructed a 25-mile liquids-rich natural gas extension on our South Texas system (the McMullen pipeline extension) to connect acreage in the Eagle Ford shale liquids-rich natural gas area; and
- we constructed a nine-mile pipeline in Jones County, Mississippi that provides us with additional capacity to supply South Mississippi Electric Power Association, or SMEPA.

Our forecast for the twelve months ending June 30, 2013 includes the capital expenditures and benefits of the following projects:

- constructing 21 miles of new pipeline to bring additional supply from DeWitt and Karnes Counties in the Eagle Ford shale area to our Woodsboro processing plant;
- constructing a dry gas line near Petronila, Texas to enhance deliveries to the Corpus Christi area;
- increasing the capacity of our Bonnie View fractionator; and
- adding compression to our South Texas system in order to increase natural gas throughput to our Woodsboro processing plant.

Please read "Our Cash Distribution Policy and Restrictions on Distributions Assumptions and Considerations Capital Expenditures" for more information regarding our anticipated capital expenditures for the twelve months ending June 30, 2013. At the closing of this offering, we expect to have availability under our new credit facility to fund the expenditures contemplated by our capital expenditures budget during our forecast period.

Business Strategies

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time by expanding the capacity and efficiency of our assets and by making selective acquisitions while ensuring the ongoing stability of our business. We expect to achieve this objective by pursuing the following business strategies:

- ***Capitalize on organic growth opportunities, with a focus on high-growth areas such as the Eagle Ford shale.*** We intend to continue to evaluate and execute midstream projects that enhance our existing systems as well as our ability to aggregate supply and obtain access to premium markets for that supply. A primary focus of our organic growth will be our South Texas assets located in and near the Eagle Ford shale area, a rapidly growing source of unconventional U.S. natural gas production that often features high condensate and NGL content.
- ***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 and adding new volumes of natural gas supplies to our existing assets.

Pursue accretive acquisitions of complementary assets. We intend to pursue accretive acquisitions that strategically expand or complement our existing asset portfolio. We monitor the marketplace to identify and pursue such acquisitions, with a particular focus on regions with potential for additional near-term development.

Manage our exposure to commodity price risk. Because natural gas and NGL prices are volatile, we will continue to mitigate the impact of fluctuations in commodity prices and to generate stable cash flows by targeting a contract portfolio that is heavily weighted towards fixed-fee and fixed-spread contracts.

Maintain sound financial practices to ensure our long-term viability. We intend to maintain our commitment to financial discipline, and we generally intend to fund the long-term capital requirements for expansion projects and acquisitions through a prudent combination of equity and debt capital.

Competitive Strengths

We believe that we are well-positioned to successfully execute our business strategies 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 area in South Texas, which is one of the most active drilling regions in the United States. In addition, all of our assets have access to major natural gas market areas.

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 helps to promote cash flow reliability and minimizes our direct exposure to commodity price fluctuations.

Integrated midstream value chain. We provide a comprehensive package of services to natural gas producers, including natural gas gathering, processing, treating, compression and transportation and NGL fractionation. We believe our ability to move producers' natural gas and NGLs from the wellhead to market provides a competitive advantage relative to competing companies that do not offer this range of midstream services.

Experienced and incentivized management and operating teams. Our executive officers have an average of 34 years of 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. Most of our field operating managers and supervisors have long-standing experience operating our assets.

Supportive sponsor with significant industry expertise. Charlesbank, the principal owner of our general partner, has substantial experience as a private equity investor in the energy and midstream sector. We believe that Charlesbank provides us with strategic guidance, financial expertise and potential capital support that enhances our ability to grow our asset base and cash flow.

Our Sponsor

Charlesbank is a leading private equity firm with over $2.0 billion of capital under management. The firm has 20 investment professionals and offices in Boston and New York. Originally managing an investment portfolio solely for Harvard University, Charlesbank broadened its investor base in 2000 to include other institutional clients. Now investing its seventh fund since 1991, Charlesbank has funded over $2.0 billion in more than 60 portfolio companies across a wide range of industries. In 2003, Charlesbank and members of our management team cofounded Regency Gas Services, a midstream company formed through the acquisition of assets from a publicly traded energy company. Over the years, Charlesbank has built deep energy experience and proven its ability to support and finance a variety of growth projects.

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Risk Factors

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited partnership structure and the tax characteristics of our common units. The following list of risk factors should be read carefully in conjunction with the risks under the caption "Risk Factors" immediately following this summary, beginning on page 18.

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 holders of our common and subordinated units.

- On a historical as adjusted basis we would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our units for the year ended December 31, 2011.

- Because of the natural decline in production from existing wells in our areas of operation, our success depends in part on producers 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 could adversely affect our business and operating results.

- Natural gas and NGL prices are volatile, and a change in these prices in absolute terms, or an adverse change in the prices of 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.

- Our exposure to direct commodity price risk may vary over time.

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

- We depend on a relatively small number of customers for a significant portion of our revenues. The loss of, or material nonpayment or nonperformance by, any one or more of these customers could adversely affect our ability to make cash distributions to you.

- Unplanned downtime associated with our assets or third-party assets interconnected with our assets could have a material adverse effect on our business and operating results.

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

- We are subject to numerous hazards and operational risks.

Risks Inherent in an Investment in Us

Holdings owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations and has limited duties to us and our unitholders. Holdings 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.

Charlesbank 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

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could adversely affect our results of operations and cash available for distribution to our unitholders.

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. Following this offering, the market price of our common units may fluctuate significantly, and you could lose all or part of your investment.

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

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.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

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, then our cash available for distribution to our unitholders would be substantially reduced.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

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

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

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Recapitalization Transactions and Partnership Structure

In connection with the closing of this offering, the following transactions will occur:

- Holdings will convey its indirect ownership interest in our operating subsidiaries to Southcross Operating, LLC, which will become our operating subsidiary;

- Holdings will convey an interest in Southcross Operating, LLC to our general partner as a capital contribution;

- Our general partner will convey its interest in Southcross Operating, LLC to us in exchange for (i) a continuation of its 2% general partner interest in us, and (ii) our incentive distribution rights, or IDRs;

- Holdings will convey its remaining interest in Southcross Operating, LLC to us in exchange for (i) common units, representing a % limited partner interest in us, (ii) subordinated units, representing a % limited partner interest in us, (iii) the assumption of its existing debt by us, (iv) the right to receive $ million sourced to new debt incurred by us and (v) the right to receive $ in cash, a portion of which will be used to reimburse Holdings for certain capital expenditures it incurred with respect to assets it contributed to us;

- We will issue common units to the public, representing a % limited partner interest in us;

- We will enter into a new $ million credit facility from which we will borrow $ million; and

- We will use the net proceeds from the offering and borrowings under our new credit facility as set forth under "Use of Proceeds."

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Ownership of Southcross Energy Partners, L.P.

The diagram below illustrates our organization and ownership after giving effect to this offering and the related recapitalization transactions and assumes that the underwriters' option to purchase additional common units is not exercised.

Public Common Units	%
Holdings Units:	
Common Units	%
Subordinated Units	%
LTIP Participants Common Units	%
General Partner Interest	%
Total	100.0%

(1) After giving effect to this offering, members of our management will beneficially own % of the Class A Common Units, % of the Series A Preferred Units, % of the Redeemable Preferred Units, % of the Series B Redeemable Preferred Units and % of the Special Class B Units of Holdings.

(2) After giving effect to this offering, Charlesbank Equity Fund VI, Limited Partnership and its affiliated investment funds will beneficially own % of the Class A Common Units, % of the Series A Preferred Units, % of the Redeemable Preferred Units and % of the Series B Redeemable Preferred Units of Holdings.

(3)

After giving effect to this offering, other individual and institutional investors will beneficially own % of the Class A Common Units, % of the Series A Preferred Units, % of the Redeemable Preferred Units and % of the Series B Redeemable Preferred Units of Holdings.

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Our Management

We are managed and operated by the board of directors and executive officers of Southcross Energy Partners GP, LLC, our general partner. Holdings, which is controlled by Charlesbank, is the sole owner of our general partner and has the right to appoint the entire board of directors of our general partner, including our three independent directors. Unlike shareholders in a publicly traded corporation, our unitholders will not be entitled to elect our general partner or the board of directors of our general partner. For more information about the directors and executive officers of our general partner, please read "Management Directors and Executive Officers" beginning on page 142.

In order to maintain operational flexibility, our operations will be conducted through, and our operating assets will be owned by, various operating subsidiaries. However, neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring employees or by obtaining the services of personnel employed by others. All of the personnel that will conduct our business immediately following the closing of this offering will be employed by our general partner and its affiliates, but we sometimes refer to these individuals in this prospectus as our employees.

Following the closing of this offering, our general partner and its affiliates will not receive any management fee or other compensation in connection with our general partner's management of our business, but will be reimbursed for expenses incurred on our behalf. These expenses include the costs of employee and director compensation and benefits properly allocable to us, and all other expenses necessary or appropriate for the conduct of our business and allocable to us. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. For the twelve months ending June 30, 2013, we estimate that these expenses will be approximately $23.9 million, which includes, among other items, compensation expense for all employees required to manage and operate our business.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201 and our telephone number is (214) 979-3700. Our website is located at www. .com and will be activated in connection with the closing of this offering. We expect to make available our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as the SEC, free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

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Summary of Conflicts of Interest and Duties

General

Our general partner has a legal duty to manage us in a manner it subjectively believes is in our best interest. However, the officers and directors of our general partner also have a fiduciary duty to manage the business of our general partner in a manner beneficial to its owners, including Charlesbank. Certain of the directors of our general partner are also officers of Charlesbank. As a result of these relationships, conflicts of interest may arise in the future between us and holders of our common units, on the one hand, and Charlesbank and our general partner, on the other hand. For example, our general partner will be entitled to make determinations that affect the amount of cash distributions we make to the holders of common units, which in turn has an effect on whether our general partner receives incentive cash distributions.

Partnership Agreement Replacement of Fiduciary Duties

Delaware law provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties owed by the general partner to limited partners and the partnership. Pursuant to these provisions, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of the general partner and the methods of resolving conflicts of interest. The effect of these provisions is to restrict the remedies available to our common unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement and, pursuant to the terms of our partnership agreement, each holder of common units consents to various actions and potential conflicts of interest contemplated in the partnership agreement that might otherwise be considered a breach of fiduciary or other duties under applicable state law.

Charlesbank May Compete Against Us

Our partnership agreement does not prohibit Charlesbank or its affiliates, other than our general partner, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Charlesbank may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to acquire or construct any of those assets.

For a more detailed description of the conflicts of interest and the duties of our general partner, please read "Conflicts of Interest and Duties."

Implications of Being an Emerging Growth Company

As a company with less than $1.0 billion in revenue during its last fiscal year, we qualify as an "emerging growth company" as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. For as long as a company is deemed an emerging growth company, it may take advantage of specified reduced reporting and other regulatory requirements that are generally unavailable to other public companies. These provisions include:

- a requirement to present only two years of audited financial statements and only two years of related Management's Discussion and Analysis included in an initial public offering registration statement;

- an exemption to provide less than five years of selected financial data in an initial public offering registration statement;

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- 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;

- reduced disclosure about the emerging growth company's executive compensation arrangements pursuant to the rules applicable to smaller reporting companies; and

- no requirement to seek non-binding advisory votes on executive compensation or golden parachute arrangements.

We may take advantage of these provisions until we are no longer an emerging growth company, which will occur on the earlier of the last day of the fiscal year following the fifth anniversary of this offering or if we have more than $1.0 billion in annual revenues, have more than $700 million in market value of our common units held by non-affiliates or issue more than $1.0 billion of non-convertible debt over a three-year period.

We have elected to adopt the reduced disclosure requirements described above, except for the following:

- we have elected to provide three years of audited financial statements and related Management's Discussion and Analysis as opposed to two years; and

- 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 (this election is irrevocable).

As a result of these elections, the information that we provide in this prospectus may be different from the information you may receive from other public companies in which you hold equity interests.

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The Offering

Common units offered to the public	common units. common units if the underwriters exercise in full their option to purchase additional common units.
Units outstanding after this offering	common units and subordinated units, each representing a 49.0% limited partner interest in us. Our general partner will own general partner units, representing a 2.0% general partner interest in us.
Use of proceeds	We intend to use the net proceeds from this offering of approximately $ million, after deducting underwriting discounts and commissions, to:

make a cash distribution to Holdings of $ million, a portion of which will be used to reimburse Holdings for certain capital expenditures it incurred with respect to assets contributed to us;

repay $ million of debt outstanding under our existing credit facility;

pay Citigroup Global Markets Inc. and Wells Fargo Securities, LLC an aggregate structuring fee of $ million; and

pay estimated offering expenses of $ million.

Holdings may use a portion of the cash distribution it receives from us to redeem all or a portion of Holdings' outstanding redeemable preferred units.

Immediately following the repayment of a portion of the outstanding balance under our existing credit facility, we will terminate our existing facility, enter into a new credit facility and borrow approximately $ million under that credit facility. We will use the proceeds from these borrowings to (i) make an ordinary course cash distribution of approximately $ million to Holdings and (ii) pay fees and expenses relating to our new credit facility of approximately $ million.

If the underwriters exercise their option to purchase additional common units, we will use the net proceeds from that exercise to redeem from Holdings the number of common units issued upon such exercise, at a price per common unit equal to the proceeds per common unit in this offering before expenses but after deducting underwriting discounts, commissions and structuring fees.

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Cash distributions	We intend to pay a minimum quarterly distribution of $ per unit ($ per unit on an annualized basis) to the extent we have sufficient cash from operations after the establishment of cash reserves and payment of fees and expenses, including payments to our general partner and its affiliates. We refer to this cash as "available cash." Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors described in more detail under the caption "Our Cash Distribution Policy and Restrictions on Distributions." We will adjust the minimum quarterly distribution payable for the period from the closing of this offering through , 2012, based on the length of that period. Our partnership agreement requires that we distribute all of our available cash each quarter in the following manner: *first*, 98.0% to the holders of common units and 2.0% to our general partner, until each common unit has received the minimum quarterly distribution of $ plus any arrearages from prior quarters; *second*, 98.0% to the holders of subordinated units and 2.0% to our general partner, until each subordinated unit has received the minimum quarterly distribution of $; and *third*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unit has received a distribution of $. If cash distributions to our unitholders exceed $ per unit in any quarter, our general partner will receive, in addition to distributions on its 2.0% general partner interest, increasing percentages, up to 48.0%, of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions." Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions." The amount of historical as adjusted available cash generated during the year ended December 31, 2011 would not have been sufficient to allow us to pay the minimum quarterly distribution on our common and subordinated units as well as the corresponding distribution on our 2.0% general partner interest during that period. Specifically, the amount of historical as adjusted available cash generated during the year ended December 31, 2011 would have been sufficient to pay only % of the aggregate minimum quarterly distribution on our common units during that period, and we would not have been able to pay any distributions on our subordinated units during that period.

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	We believe that, based on our estimated cash available for distribution included under the caption "Our Cash Distribution Policy and Restrictions on Distributions," we will have sufficient cash available for distribution to pay the annualized minimum quarterly distribution of $ per unit on all common and subordinated units, as well as the corresponding distribution on our 2.0% general partner interest, for the twelve months ending June 30, 2013. However, we do not have a legally binding obligation to pay quarterly distributions at our minimum quarterly distribution rate or any other rate except as provided in our partnership agreement. There is no guarantee that we will distribute quarterly cash distributions to our unitholders in any quarter. Please read "Our Cash Distribution Policy and Restrictions on Distributions."
Subordinated units	Holdings will initially own all of our subordinated units. 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 will not accrue arrearages.
Conversion of subordinated units	The subordination period will end on the first business day after the partnership has earned and paid at least (1) $ (the minimum quarterly distribution on an annualized basis) on each outstanding common unit and subordinated unit and the corresponding distribution on the general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after , 2015 or (2) $ (150.0% of the annualized minimum quarterly distribution) on each outstanding common unit and subordinated unit and the corresponding distribution on the general partner's 2.0% interest and the related distribution on the incentive distribution rights for the four quarter period immediately preceding that date, in each case provided there are no arrearages on the common units at that time. The subordination period also will end upon the removal of the general partner other than for cause if no subordinated units or common units held by the holder(s) of subordinated units or their affiliates are voted in favor of that removal. When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and thereafter no common units will be entitled to arrearages.

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Limited voting rights	Our general partner will manage and operate us. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or its directors on an annual or continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3$% of the outstanding limited partner units voting together as a single class, including any limited partner units owned by our general partner and its affiliates, including Holdings. Upon the closing of this offering, Holdings will own an aggregate of % of our common and subordinated units (or % of our outstanding common and subordinated units if the underwriters exercise in full their option to purchase additional units). This will give Holdings the ability to prevent the involuntary removal of our general partner. Please read "The Partnership Agreement Voting Rights."
Limited call right	If at any time our general partner and its affiliates own more than 80.0% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price that is not less than the then-current market price of the common units.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2015, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be % or less of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $ per unit, we estimate that your average allocable federal taxable income per year will be no more than $ per unit. Please read "Material Federal Income Tax Consequences Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions" and "Material Federal Income Tax Consequences Tax Consequences of Unit Ownership Limitations on Deductibility of Losses."
Material federal income tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, or the U.S., please read "Material Federal Income Tax Consequences."
Directed unit program	At our request, the underwriters have reserved up to % of the common units being offered by this prospectus for sale at the initial public offering price to the directors, officers and employees of our general partner and certain other persons associated with us through a directed unit program. For further information regarding our directed unit program, please read "Underwriting."
Exchange listing	We intend to apply to list our common units on the New York Stock Exchange, or NYSE, under the symbol "SXE."

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Summary Historical and Pro Forma Financial and Operating Data

The following table presents, as of the dates and for the periods indicated, our summary historical and pro forma consolidated financial and operating data, as well as the summary historical combined financial and operating data of our Predecessor.

The summary historical combined financial data for the period from January 1, 2009 to July 31, 2009 is derived from the audited historical combined financial statements of our Predecessor included elsewhere in this prospectus. The summary historical combined balance sheet data as of July 31, 2009 is derived from the unaudited historical combined financial statements of our Predecessor that are not included in this prospectus. The summary historical consolidated balance sheet data presented as of December 31, 2009 of Southcross Energy LLC is derived from the audited historical consolidated financial statements of Southcross Energy LLC that are not included in this prospectus. The summary historical consolidated financial data presented as of December 31, 2010 and December 31, 2011 and for the period from June 2, 2009 (date of inception) to December 31, 2009 and for the years ended December 31, 2010 and December 31, 2011 have been derived from the audited historical consolidated financial statements of Southcross Energy LLC included elsewhere in this prospectus. The summary historical consolidated financial data presented as of March 31, 2012 and for the three months ended March 31, 2011 and March 31, 2012 are derived from our unaudited historical condensed financial statements included elsewhere in this prospectus. We acquired our initial assets from Crosstex effective as of August 1, 2009. During the period from our inception on June 2, 2009 to July 31, 2009, we had no operations, although we incurred certain fees and expenses of approximately $3.0 million associated with our formation and the acquisition of our initial assets from Crosstex, which are reflected in the "Transaction costs" line item of our summary historical consolidated financial data for the period from June 2, 2009 (date of inception) to December 31, 2009.

The summary pro forma consolidated financial data for the three months ended March 31, 2012 and for the year ended December 31, 2011 have been derived from our unaudited pro forma consolidated financial statements included elsewhere in this prospectus. The summary pro forma consolidated statement of operations for the year ended December 31, 2011 includes the pro forma effects of the EAI acquisition and the pro forma effects of the recapitalization transactions described under " Recapitalization Transactions and Partnership Structure" as if the EAI acquisition and the recapitalization transactions occurred as of January 1, 2011. The summary pro forma consolidated statement of operations for the three months ended March 31, 2012 presents the pro forma effects of the recapitalization transactions as if they occurred as of January 1, 2011.

For a detailed discussion of the following table, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations." The following table should also be read in conjunction with the historical audited and unaudited consolidated financial statements and related notes of Southcross Energy LLC and our Predecessor's audited combined financial statements and related notes included elsewhere in this prospectus. Among other things, those historical financial

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statements include more detailed information regarding the basis of presentation for the information below.

	Southcross Energy Predecessor Period from January 1, 2009 to July 31,	Southcross Energy LLC					Pro Forma Southcross Energy Partners, L.P.	
		Period from June 2, 2009 to December 31,	Year Ended December 31,		Three Months Ended March 31,		Year Ended December 31,	Three Months Ended March 31,
	2009	2009	2010	2011(3)	2011	2012	2011	2012
	(in thousands, except for volume and price amounts)							
Statement of Operations Data:								
Total Revenue	$ 330,870	$ 206,634	$ 498,747	$ 523,149	$ 120,999	$ 120,617	$ 548,152	$ 120,617
Expenses:								
Cost of natural gas and liquids sold	301,368	179,045	439,431	460,580	105,752	99,202	479,376	99,202
Operations and maintenance	10,648	7,847	21,106	24,707	4,834	7,197	28,701	7,197
Depreciation and amortization	7,268	4,235	10,987	12,345	2,795	3,665	13,200	3,665
General and administrative	9,788	3,225	7,341	8,926	1,970	2,433	9,312	2,433
Transaction costs		2,957	149	203			203	
Total expenses	329,072	197,309	479,014	506,761	115,351	112,497	530,792	112,497
Income from operations	1,798	9,325	19,733	16,388	5,648	8,120	17,360	8,120
Interest income		9	25	24	8	2	24	2
Loss on extinguishment of debt				(3,240)			(3,240)	
Interest expense		(4,554)	(10,038)	(5,372)	(1,634)	(1,801)	(7,307)	(1,212)
Income tax expense	(77)	(372)	(1)	(261)	(65)	(85)	(261)	(85)
Net income	$ 1,721	$ 4,408	$ 9,719	$ 7,539	$ 3,957	$ 6,236	$ 6,576	$ 6,825
Statement of Cash Flows Data:								
Net cash provided by (used in):								
Operating activities	$ 4,955	$ 10,164	$ 25,493	$ 20,007	$ 272	$ 4,638		
Investing activities	(791)	(238,339)	(5,231)	(144,602)	(14,882)	(38,912)		
Financing activities	(4,164)	233,899	(5,663)	105,684	(4,766)	46,847		
Balance Sheet Data (at period end):								
Cash and cash equivalents	$	$ 5,724	$ 20,323	$ 1,412	$ 947	$ 13,985		
Trade accounts receivable	50,707	39,956	35,059	41,234	32,942	35,670		
Property, plant, and equipment, net	111,645	235,065	229,309	369,861	244,658	411,825		
Total assets	167,503	287,808	289,643	420,385	282,954	470,810		
Total debt (current and long term)		119,949	115,000	208,280	110,234	237,408		
Other Financial Data:								
Adjusted EBITDA(1)	$ 9,236	$ 16,517	$ 30,869	$ 28,936	$ 8,443	$ 11,785	$ 30,763	$ 11,785
Gross operating margin(2)	29,502	27,589	59,316	62,569	15,247	21,415	68,776	21,415
Maintenance capital expenditures	565	3,025	3,402	5,317	502	348	5,423	348
Expansion capital expenditures	250	1,669	1,843	150,669	17,642	45,266	150,669	45,266
Operating data:								
Average throughput of gas (MMBtu/d)	592,243	492,350	471,265	506,975	452,941	583,198	532,746	583,198
Average volume of NGLs delivered (Mgal/d)	241.8	225.5	233.4	215.5	220.3	385.2	215.5	385.2
Average volume input to our processing plants (MMBtu/d)	100,596	96,135	95,336	97,028	85,806	122,517	97,028	122,517
Realized prices on natural gas volumes sold/Btu ($/MMBtu)	$ 3.95	$ 3.97	$ 4.42	$ 4.05	$ 4.14	$ 2.69	$ 4.07	$ 2.69
Realized prices on NGL volumes sold/gal ($/gal)	$ 0.69	$ 1.01	$ 1.10	$ 1.35	$ 1.19	$ 1.05	$ 1.35	$ 1.05

(1) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures," and for a discussion of how we use Adjusted EBITDA to evaluate our operating performance, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations."

(2) For a definition of gross operating margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures," and for a discussion of how we use gross operating margin to evaluate our operating performance, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations."

(3) The Summary Historical Financial and Operating Data for the year ended December 31, 2011 includes four months of financial and operating results for the EAI acquisition.

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RISK FACTORS

Limited partner units 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 similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

If any of the following risks were to materialize, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment in us.

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 holders of our common and subordinated units.

In order to pay the minimum quarterly distribution of $ per unit per quarter, or $ per unit on an annualized basis, we will require available cash of approximately $ million per quarter, or $ million per year, based on the number of common and subordinated units to be outstanding immediately after completion of this offering. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution. 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;
- the level of production of oil and natural gas and the resultant market prices of 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 services;
- outages at the processing or fractionation facilities owned by us or third parties caused by mechanical failure and maintenance, construction and other similar activities;
- 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 pricing impacts on our revenue and expenses that are directly subject to commodity price exposure;
- 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 and general and administrative costs; and

- 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.

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

- 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.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please read "Our Cash Distribution Policy and Restrictions on Distributions."

On a historical as adjusted basis we would not have had sufficient cash available for distribution to pay the full minimum quarterly distribution on all of our units for the year ended December 31, 2011.

The amount of historical as adjusted cash available for distribution generated during the year ended December 31, 2011 was $17.1 million, which would have allowed us to pay only % of the aggregate minimum quarterly distribution on all of our common units during that period, and we would not have been able to pay any distributions on our subordinated units during that period. For a calculation of our ability to make cash distributions to our unitholders based on our historical as adjusted results, please read "Our Cash Distribution Policy and Restrictions on Distributions." If we are not able to generate additional cash for distribution to our unitholders in future periods, we may not be able to pay the full minimum quarterly distribution or any amount on our common or subordinated units, in which event the market price of our common units may decline materially.

The assumptions underlying the forecast of cash available for distribution that we include in "Our Cash Distribution Policy and Restrictions on Distributions" are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted.

The forecast of cash available for distribution set forth in "Our Cash Distribution Policy and Restrictions on Distributions" includes our forecasted results of operations, Adjusted EBITDA and cash available for distribution for the twelve months ending June 30, 2013. The financial forecast has been prepared by management, and we have not received an opinion or report on it from our or any other independent auditor. The assumptions underlying the forecast are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks, including risks that expansion projects do not result in an increase in gathered, processed, transported and sold volumes, and uncertainties that could cause actual results to differ materially from those forecasted. If we do not achieve the forecasted results, we may not be able to pay the full minimum quarterly distribution or any amount on our common or subordinated units, in which event the market price of our common units may decline materially.

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Because of the natural decline in production from existing wells in our areas of operation, our success depends in part on producers 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 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 will also 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 oil, natural gas and NGL prices;
- demand for 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 oil and natural gas reserves. Drilling and production activity generally decreases as natural gas prices decrease. Further declines in natural gas prices could have a negative impact on exploration, development and production activity, and if sustained, 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.

Because of these and other factors, even if natural gas 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 intend to obtain independent evaluations of natural gas 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 intend to obtain independent evaluations of natural gas reserves connected to our systems on a regular or ongoing basis. Accordingly, we may 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

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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 and our ability to attract and maintain customers in a limited number of geographic areas.

A significant portion of our assets is located in the Eagle Ford shale area, 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 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. For example, a change in the rules and regulations governing operations in or around the Eagle Ford shale area could cause producers to reduce or cease drilling or to permanently or temporarily shut-in their production within the area, which could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Natural gas and NGL prices are volatile, and a change in these prices in absolute terms, or an adverse change in the prices of 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 may be materially adversely affected if we experience significant, prolonged pricing deterioration. For example, if there is a significant change in the relative prices of NGLs and natural gas, it will impact our processing margins, which are a significant component of our ability to generate cash for distribution to our unitholders.

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;
- 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 oil, natural gas, NGLs and other commodities.

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Our exposure to direct commodity price risk may vary over time.

We currently generate a majority of our revenues pursuant to fixed-fee contracts under which we are paid based on the volumes of natural gas that we gather, treat, transport and process and the volumes of NGLs we fractionate, rather than the value of the underlying natural gas or NGLs. Consequently, the majority of our existing operations and cash flows have limited direct exposure to commodity price risk. 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. In addition, we may acquire or develop additional midstream assets or change the arrangements under which we process our volumes, in either case, in a manner that increases our exposure to commodity price risk. Future exposure to the volatility of oil and natural gas prices could have a material adverse effect on our business, results of operations and financial condition.

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 or at pipeline pooling points. Sales made to natural gas marketers and power generation, industrial and utility customers 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 other purchasers. We are exposed to fluctuations in the price of natural gas through volumes sold pursuant to percent-of-proceeds 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 do not enter into natural gas hedge contracts, but rather 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. For example, we are currently net purchasers of natural gas on certain of our systems and net sellers of natural gas on certain of our other systems. 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 an identical volume of natural gas at delivery points on our systems, we may not be able to mitigate all exposure to commodity price risks. For example, the volumes or timing of our purchases and sales may not correspond. In addition, a producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of 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.

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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 NGLs 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 NGLs 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 renewal risks.

We gather, purchase, process, 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. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with fixed-fee or fixed-spread contracts may desire to enter into gathering and transportation contracts under different fee arrangements, or a producer with whom we have a natural gas purchase contract may choose to enter into a transportation contract with us and retain title to its natural gas. 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 small number of customers for a significant portion of our revenues. The loss of, or material nonpayment or nonperformance by, any one or more of these customers could adversely affect our ability to make cash distributions to you.

A significant percentage of our revenue is attributable to a relatively small number of customers. Our top ten customers accounted for approximately 73.1% and 73.6% of our revenue for the year ended December 31, 2011 and for the three months ended March 31, 2012, respectively. We have gathering, processing and/or transmission contracts with each of these customers of varying duration and commercial terms. If we were 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. Two customers, Formosa Hydrocarbons Company, Inc., or Formosa, and Sherwin Alumina Company accounted for approximately 20.8% and 15.5%, respectively, of our revenue for the year ended December 31, 2011. We supply natural gas to Sherwin Alumina Company to be used in their manufacturing process. In the case of Formosa, we have a contract to sell to Formosa natural gas that is supplied to us by our producers for processing at its facility. We then share in the value stream created by Formosa's processing plant. Our ability to use Formosa's processing facility will expire in January 2013 and we do not intend to renew this contract. We expect that we will have the ability to take the same natural gas volume from our producers and process it at our own facilities, in particular at our new Woodsboro processing facility. If Formosa denies us access to its processing facility prior to January 2013, it may have a material adverse effect on our revenue, cash flows and our

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ability to make cash distributions to our unitholders. In addition, some of our customers may have material financial and liquidity issues or may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better-capitalized companies. Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our revenue, gross operating margin and cash flows and our ability to make cash distributions to our unitholders. In any of these situations, our revenue and cash flows and our ability to make cash distributions to our unitholders may be adversely affected. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our revenue.

If third-party pipelines or other midstream facilities interconnected to our gathering or transportation systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our gross operating margin and 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 facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties, such as Tennessee Gas Pipeline Company, Florida Gas Transmission Company, LLC, Gulf South Pipeline Company, LP, Kinder Morgan Energy Partners LP, Southern Natural Gas Company, Energy Transfer Partners, L.P., Seadrift Pipeline Corporation and others. The continuing operation of such third-party pipelines, processing plants and other midstream facilities is not within our control. These pipelines, plants and other midstream 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 hurricanes 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 or transport do not meet the natural gas quality requirements of such pipelines or facilities, our gross margin and ability to make cash distributions to our unitholders could be adversely affected. For example, for 31 days in September and October 2011, Formosa shut down its processing plant in order to expand its facilities, thereby causing us to curtail natural gas supply while shutting in our deliveries to Formosa's processing plant.

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.

We purchased the majority of our assets from Crosstex in August 2009. Significant portions of the pipeline systems and processing plants that we purchased have been in service for many decades. Our executive management team was hired shortly before that purchase and, consequently, has a limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems that our executive management team may be unaware of 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.

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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 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 of NGLs, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

For example

- During the month of September 2008, before we acquired it, the Gregory processing plant temporarily shut down after Hurricane Ike made landfall because there was no outlet for its produced NGL product;
- In May 2011, flooding associated with high water on the Mississippi River caused a force majeure event that shut down deliveries through and revenue on our Delta pipeline for 20 days; and
- In June and July 2011, the molecular sieve support screen failed in the Gregory processing plant dehydrator vessel. We shut down the plant for approximately one month to make necessary repairs.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in 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. For example our business interruption/loss of income insurance provides limited coverage in the event of damage to any of our underground facilities. 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.

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We intend to grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms from third parties, our future growth will 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, on 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.

If we are unable to make accretive acquisitions from 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 or (iii) outbid by competitors or for any other reason, then our future growth and ability to increase cash distributions will 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 its 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.

Our acquisition strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow through acquisitions.

We continuously consider and enter into discussions regarding potential acquisitions. Any limitations on our access to new capital will impair our ability to execute this strategy. 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 execute our acquisition strategy.

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 fully execute our growth strategy.

Because our common units will be 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.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

As of March 31, 2012, we had total indebtedness of $237.4 million. 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 future financial and operating performance, which will be affected by prevailing economic conditions and 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.

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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, treating, processing and transporting of natural gas and the fractionation of NGLs requires 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 new credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and value of our common units.

We intend to enter into a new credit facility in connection with the closing of this offering. Our new credit facility is likely to limit our ability to, among other things:

- incur or guarantee additional debt;
- 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 new credit facility also will likely contain covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

The provisions of our new 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 new credit facility could result in a default or an event of default that could enable our lenders 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.

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. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Congress continues to consider 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. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available in 2012. In addition, on October 20, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to develop standards for wastewater discharges from hydraulic fracturing and other natural gas production activities.

Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. For example, on December 13, 2011 the Texas Railroad Commission adopted the Hydraulic Fracturing Chemical Disclosure Rule implementing a state law passed in June 2011, requiring public disclosure of hydraulic fracturing fluid contents for wells drilled under drilling permits issued after February 1, 2012. We cannot predict whether any other legislation will be enacted and if so, what its provisions would be. If additional levels of regulation and permits are required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and prohibitions for producers who drill near our pipelines which could reduce the volumes of natural gas available to move through our gathering systems which could materially adversely affect our revenue and results of operations.

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 new rule addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. The rule also establishes specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. This rule may require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. Compliance with such rules 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.

Our pipelines may become subject to more stringent safety regulation.

Recently enacted pipeline safety legislation, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The Pipeline and Hazardous Materials Safety Administration of the DOT has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation service due to more stringent and comprehensive safety regulation and higher penalties for violations of those regulations.

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 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. 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 by federal, state or local regulatory agencies or a change in policy by those agencies 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 (whether or not they provide interstate transportation services) are exempt from the jurisdiction of the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or NGA. Although the 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 the FERC has used to determine if a pipeline is a gathering pipeline and is therefore not subject to the 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, the 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 the FERC on a case-by-case basis. If the 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, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA. 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 the Natural Gas Policy Act of 1978, 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 cost-based rate established by the FERC.

Some of our intrastate pipelines provide interstate transportation service regulated under Section 311 of the Natural Gas Policy Act of 1978, or NGPA. Rates charged under NGPA Section 311 are limited to rates deemed by FERC to be "fair and equitable." 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

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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. The 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 business. In addition, the classification and regulation of our gathering and intrastate transportation facilities also are subject to change based on future determinations by the 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, the 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 these companies transferring gathering facilities to federally 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.

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

Our natural gas gathering, compression, treating and transportation operations and NGLs 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. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, and analogous state laws that regulate the cleanup of hazardous substances that may be or have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;
- the federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the federal Oil Pollution Act, also known as OPA, and analogous state laws that establish strict liability for releases of oil into waters of the United States;
- the federal Resource Conservation and Recovery Act, also known as RCRA, and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities;
- the Endangered Species Act, also known as the ESA; and
- the Toxic Substances Control Act, also known as TSCA, and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

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

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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 U.S. Environmental Protection Agency, or 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 hydrocarbon wastes 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. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. 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. Please read "Business Environmental Matters" for more information.

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

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the DOT, through its Pipeline and Hazardous Materials Safety Administration, 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 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.

Moreover, the recently enacted Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 could result in the adoption of additional regulatory requirements that will apply to us. 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 natural gas 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 our Gregory and Gulf Coast Systems. We currently estimate that we will incur future costs of approximately $2.4 million during 2012 to complete the testing required by existing DOT regulations and their state counterparts. This estimate does not include the costs for any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which could be substantial. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. If future DOT pipeline integrity management regulations were to require that we expand our integrity management program to currently unregulated pipelines, including gathering lines, costs associated with compliance may have a material effect on our operations.

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

In recent years, the U.S. Congress has considered legislation to restrict or regulate emissions of greenhouse gases, or GHGs, such as carbon dioxide and methane, that may be contributing to global warming. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that smaller sources such as our gas-fired compressors could become subject to GHG-related regulation. Depending on the particular program, we could be required to control emissions or to purchase and surrender allowances for GHG emissions resulting from our operations.

Independent of Congress, the EPA is beginning to adopt regulations controlling GHG emissions under its existing Clean Air Act authority. For example, on December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In 2009, the EPA adopted rules regarding regulation of GHG emissions from motor vehicles. In addition, on September 22, 2009, the EPA issued a final rule requiring the monitoring and reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. Our Gregory and Conroe processing facilities are currently required to report under this rule beginning in 2011. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect on December 30, 2010, requires reporting of greenhouse gas emissions by regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. Currently, it is anticipated that several of our facilities will likely be required to report under this rule. However, operational or regulatory changes could require some or all of our other facilities to be required to report GHG emissions at a future date. In 2010, EPA also issued a final rule, known as the "Tailoring Rule," that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act. Several of the EPA's greenhouse gas rules are being challenged in pending court proceedings and, depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Although it is not possible at this time to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business, any future federal or state laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the natural gas we gather, treat or otherwise handle in connection with our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of greenhouse gases could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas, resulting in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations.

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

In July 2010 federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was enacted. The Dodd-Frank Act provides new statutory requirements for swap transactions, including oil and gas hedging transactions. These statutory requirements must be implemented through regulation, primarily through rules to be adopted by the Commodity Futures Trading Commission, or the CFTC. The Dodd-Frank Act provisions are intended to change fundamentally the way swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which most swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. Many market participants will be newly regulated as swap dealers or major swap participants, with new regulatory capital requirements and other regulations that may impose business conduct rules and mandate how they hold collateral or margin for swap transactions. All market participants will be subject to new reporting and recordkeeping requirements.

The impact of the Dodd-Frank Act on our hedging activities is uncertain at this time, and the CFTC has not yet promulgated final regulations implementing the key provisions. Although we do not believe we will need to register as a swap dealer or major swap participant, and do not believe we will be subject to the new requirements to trade on an exchange or swap execution facility or to clear swaps through a central counterparty, we may have new regulatory burdens. Moreover, the changes to the swap market as a result of Dodd-Frank implementation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps.

Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore reduce our willingness or ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key management personnel.

Our ability to operate our business and implement our strategies will depend on our 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 our senior executives and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate 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.

Upon the completion of this offering, we will become subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act, including the rules thereunder that will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management 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 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.

Although we will be required to disclose changes made in our internal control and procedures on a quarterly basis, we will not be required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 until the fiscal year ending December 31, 2013. In addition,

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pursuant to the recently enacted JOBS Act, our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal control over financial reporting until the later of the year following our first annual report required to be filed with the SEC or the date we are no longer an "emerging growth company," which may be up to five full fiscal years following this offering.

The amount of cash we have available for distribution to holders of our common and subordinated 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 owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations and has limited duties to us and our unitholders. Holdings 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.

Following this offering, Holdings will control our general partner, and appoint all of the officers and directors of our general partner, some of whom will also be officers of Charlesbank, the entity that controls Holdings. 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 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.
- 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 an expansion 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 $ 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 intends to limit 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.

Please read "Conflicts of Interest and Duties."

Charlesbank 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.

Charlesbank is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. For example, Charlesbank owns an interest in the general partner of a publicly traded midstream master limited partnership, which, in the future, may engage in the natural gas gathering and processing segment of the midstream industry and conduct business in our areas of operation. In addition, in the future, Charlesbank may 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 Charlesbank may offer us the opportunity to buy additional assets from it, it is under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed. Charlesbank is a leading private equity firm with significantly greater resources than us and has experience making investments in midstream energy businesses. Charlesbank may compete with us for investment opportunities and may own interests in entities that compete with us.

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Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors, and Charlesbank. 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. Please read "Conflicts of Interest and Duties."

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. Following this offering, the market price of our common units may fluctuate significantly, and you could lose all or part of your investment.

Prior to this offering, there has been no public market for our common units. After this offering, there will be only publicly traded common units, assuming no exercise of the underwriters' option to purchase additional common units. In addition, affiliates of our general partner will own common and subordinated units, representing an aggregate % limited partner interest in us. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. You may not be able to resell your common units at or above the initial public offering price. Additionally, the 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 initial public offering price for the common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- 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 after this offering or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these "Risk Factors."

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit 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.

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 expansion 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, because 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 expansion 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, and we do not anticipate there being limitations in our new 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 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 has ended. At the closing of this offering, affiliates of our general partner will own, directly or indirectly, approximately % of the outstanding common units and all of our outstanding subordinated units. Please read "The Partnership Agreement Amendment of Our Partnership Agreement."

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

Prior to making any distribution on our common units, we will 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 will reimburse our general partner and its affiliates for certain expenses incurred on our behalf, which we project to be approximately $23.9 million for the twelve months ending June 30, 2013 and includes, 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 will reduce the amount of available cash to pay cash distributions to our common unitholders. Please read "Our Cash Distribution Policy and Restrictions on Distributions."

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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. Please read "Conflicts of Interest and Duties Duties of our General Partner."

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 the partnership 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 fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

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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;

- 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 the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Please read "Conflicts of Interest and Duties."

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 the 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. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions General Partner's Right to Reset Incentive Distribution Levels."

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 will 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 initially remove our general partner without its consent.

The unitholders initially will be unable to remove our general partner without its consent because our general partner and its affiliates will own sufficient units upon the closing of this offering 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. Following the closing of this offering, affiliates of our general partner will own % of our outstanding common and subordinated units. 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 or wanton 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 our partnership 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

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ownership interest in our general partner to a third party. The new owner of our 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.

You will experience immediate and substantial dilution in net tangible book value of $ per common unit.

The estimated initial public offering price of $ per common unit exceeds our net tangible book value of $ per unit. Based on the estimated initial public offering price of $ per common unit, you will incur immediate and substantial dilution of $ per common unit. This dilution results primarily because the assets contributed by our general partner and its affiliates are recorded in accordance with GAAP at their historical cost, and not their fair value. Please read "Dilution."

We may issue additional units without your approval, which would dilute your existing ownership interests.

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

After the sale of the common units offered by this prospectus, assuming that the underwriters do not exercise their option to purchase additional common units, Holdings will hold an aggregate of common units and subordinated units. All of the subordinated units will convert into common units at the end of the subordination period. 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. At the closing of this offering, and assuming no exercise of the underwriters' option to purchase additional common units, Holdings will own approximately % of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), Holdings will own

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approximately % of our outstanding common units. For additional information about this right, please read "The Partnership Agreement Limited Call Right."

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

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

For a discussion of the implications of the limitations of liability on a unitholder, please read "The Partnership Agreement Limited Liability."

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 the partnership 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 their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

We intend to apply to list our common units on the NYSE. Because we will be a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. Please read "Management."

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses. In addition, Sarbanes-Oxley and related rules subsequently implemented by the SEC and the NYSE have required changes in the corporate governance practices of publicly traded companies. We expect these rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded partnership, we are required to have at least three

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independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly traded partnership reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance and to possibly result in our general partner having to accept reduced policy limits and coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers.

We have included $2.2 million of estimated incremental annual costs associated with being a publicly traded partnership in our financial forecast included elsewhere in this prospectus. However, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

If we are deemed to be an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our initial assets will consist of our ownership interests in our operating subsidiaries. If a sufficient amount of our other assets are deemed to be "investment securities," within the meaning of the Investment Company Act of 1940, or the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or contract rights so as to fall outside of the definition of investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property from or to our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal income tax on our taxable income at the corporate tax rate, distributions to you would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to you. If we were taxed as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as an investment company would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units. For a discussion of the federal income tax implications that would result from our treatment as a corporation in any taxable year, please read "Material Federal Income Tax Consequences Partnership Status."

Tax Risks

In addition to reading the following risk factors, please read "Material Federal Income Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

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, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

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. Although we do not believe based upon our current operations that we are or will be so treated, 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 you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes, 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.

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.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread 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 the cash available for distribution to you. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, 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 potential 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. Members of the U.S. Congress have considered substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships; any such legislation, if enacted, may or may not be applied retroactively. We are unable to predict whether any such legislation will ultimately be enacted, and any such changes could negatively impact the value of an investment in our common units.

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

Because a unitholder will be treated as a partner to whom we will allocate taxable income which could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if it 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.

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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.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we 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 of our counsel's conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel's conclusions or 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.

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

If you sell your common units, you will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized on any sale of your 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 you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read "Material Federal Income Tax Consequences Disposition of Common Units Recognition of Gain or Loss."

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.

Investment in 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, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We will 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 will adopt 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 you. Our counsel is unable to opine as to the validity of such filing positions. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read "Material Federal Income Tax Consequences Tax Consequences of Unit Ownership Section 754 Election."

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 day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We will 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 day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations and, although the U.S. Treasury Department issued proposed regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. Accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Please read "Material Federal Income Tax Consequences Disposition of Common Units Allocations Between Transferors and Transferees."

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, he 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. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to effect a short sale of common units; therefore, our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We will adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable

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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 his 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 tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently 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, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years. Please read "Material Federal Income Tax Consequences Disposition of Common Units Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

As a result of investing in our common units, you may become 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 will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we 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 initially expect to conduct business in Texas, Mississippi and Alabama. 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 your responsibility to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

USE OF PROCEEDS

We expect to receive net proceeds of approximately $ million, after deducting underwriting discounts and commissions, from the issuance and sale of common units offered by this prospectus. Our estimates assume an initial public offering price of $ per common unit. We will use the net proceeds from this offering to:

- make a cash distribution to Holdings of $ million, a portion of which will be used to reimburse Holdings for certain capital expenditures it incurred with respect to assets contributed to us;
- repay $ million of debt outstanding under our existing credit facility;
- pay Citigroup Global Markets Inc. and Wells Fargo Securities, LLC an aggregate structuring fee of $ million; and
- pay estimated offering expenses of $ million.

Holdings may use a portion of the cash distribution it receives from us to redeem all or a portion of Holdings' outstanding redeemable preferred units.

Immediately following the repayment of a portion of the outstanding balance under our existing credit facility with the net proceeds of this offering, we will terminate our existing credit facility, enter into a new credit facility and borrow approximately $ million under that credit facility. We will use the proceeds from these borrowings to (i) make an ordinary course cash distribution of approximately $ million to Holdings and (ii) pay fees and expenses of approximately $ million relating to our new credit facility.

As of April 30, 2012, we had approximately $237.4 million of indebtedness outstanding under our existing credit facility with a weighted average interest rate of 3.4%. The revolving credit facility matures on June 10, 2016, and borrowings bear interest at a variable rate per annum equal to the lesser of LIBOR, plus the applicable margins ranging from 2.25% to 3.25%, or at a base rate, plus applicable margins ranging from 1.25% to 2.25%. Borrowings made under our credit facility within the last twelve months were used primarily to fund capital expenditures.

If the underwriters exercise their option to purchase additional common units, we will use the net proceeds from that exercise to redeem from Holdings a number of common units equal to the number of common units issued upon such exercise, at a price per common unit equal to the proceeds per common unit in this offering before expenses but after deducting underwriting discounts, commissions and structuring fees.

An increase or decrease in the initial public offering price of $1.00 per common unit would cause the net proceeds from the offering, after deducting underwriting discounts, commissions and structuring fees, to increase or decrease, respectively, by $ million. In addition, we may also increase or decrease the number of common units we are offering. Each increase of 1.0 million common units offered by us, together with a concurrent $1.00 increase in the assumed public offering price of $ per common unit, would increase net proceeds to us from this offering by approximately $ million. Similarly, each decrease of 1.0 million common units offered by us, together with a concurrent $1.00 decrease in the assumed initial offering price of $ per common unit, would decrease the net proceeds to us from this offering by approximately $ million. To the extent there is an increase or decrease in the net proceeds we receive from this offering, we will make a corresponding increase or decrease in our cash distribution to Holdings.

The underwriters may, from time to time, engage in transactions with and perform services for us and our affiliates in the ordinary course of business. Affiliates of the underwriters are lenders under our existing credit facility and will, in that respect, receive a portion of the proceeds from this offering through the repayment of borrowings outstanding under our credit facility. Please read "Underwriting."

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CAPITALIZATION

The following table shows:

- the historical capitalization of Southcross Energy LLC, as of March 31, 2012; and
- the as adjusted capitalization of Southcross Energy Partners, L.P., as of March 31, 2012, giving effect to:
  - the receipt and use of net proceeds of $ million from this offering in the manner described in "Use of Proceeds";
  - the entry into and borrowing of $ million under our new credit facility and the use of such borrowings in the manner described in "Use of Proceeds"; and
  - the other transactions described in "Summary Recapitalization Transactions and Partnership Structure."

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, our historical consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations." This table assumes that the underwriters' option to purchase additional common units is not exercised.

	As of March 31, 2012	
	Historical	As Adjusted
	(in thousands)	
Cash and cash equivalents	$ 13,985	
Long-Term Debt:		
Existing credit facility(1)	237,408	
New credit facility		
Total long-term debt (including current maturities)	237,408	
Redeemable preferred units(2)	17,296	
Redeemable preferred units Series B(2)	35,491	
Preferred units(2)	153,995	
Equity:		
Common equity	1,342	
Common units		
Subordinated units		
General partner equity		
Accumulated deficit	(25,251)	
Total equity	(23,909)	
Total capitalization	$ 420,281	

(1)

As of April 30, 2012, we had approximately $237.4 million of indebtedness outstanding under our existing credit facility.

(2) Represents preferred units in Southcross Energy LLC (Holdings), which will remain a part of Holdings' capitalization.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the pro forma net tangible book value per unit after the offering. On a pro forma basis as of March 31, 2012, after giving effect to the offering of common units and the application of the related net proceeds, and assuming the underwriters' option to purchase additional common units is not exercised, our net tangible book value was $ million, or $ per unit. Net tangible book value excludes $ million of net intangible assets. Purchasers of common units in this offering will experience substantial and immediate dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Assumed initial public offering price per common unit		$
Net tangible book value per unit before the offering(1)	$	
Increase in net tangible book value per unit attributable to purchasers in the offering		
Less: Pro forma net tangible book value per unit after the offering(2)		
Immediate dilution in tangible net book value per common unit to purchasers in the offering(3)		$

(1) Determined by dividing the number of units (common units, subordinated units and the 2.0% general partner interest) held by our general partner and its affiliates, including Holdings, into the net tangible book value of our assets.

(2) Determined by dividing the total number of units to be outstanding after this offering (common units, subordinated units and the 2.0% general partner interest) into our pro forma net tangible book value, after giving effect to the application of the expected net proceeds of this offering.

(3) If the initial public offering price were to increase or decrease by $1.00 per common unit, then dilution in net tangible book value per common unit would equal $ and $, respectively.

The following table sets forth the number of units that we will issue and the total consideration to be contributed to us by our general partner and its affiliates and by the purchasers of common units in this offering upon the closing of the transactions contemplated by this prospectus:

	Units Acquired		Total Consideration	
	Number	Percent	Amount (in thousands)	Percent
General partner and affiliates(1)(2)		%	$	%
Purchasers in the offering				
Total		100.0%	$	100.0%

(1) The units acquired by our general partner and its affiliates, including Holdings, consist of common units, subordinated units and the 2.0% general partner interest.

(2) Assumes the underwriters' option to purchase additional common units is not exercised.

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OUR CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with the factors and assumptions upon which our cash distribution policy is based, which are included under the heading " Assumptions and Considerations" below. In addition, please read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business. For additional information regarding our historical operating results, you should refer to our historical consolidated financial statements and related notes and our Predecessor's historical combined financial statements and related notes included elsewhere in this prospectus.

General

Rationale for Our Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects our belief that our unitholders will be better served if we distribute, rather than retain, our available cash. Generally, our available cash is the sum of our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that our unitholders will receive quarterly distributions from us. We do not have a legal obligation to pay the minimum quarterly distribution or any other distribution except as provided in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

- Our cash distribution policy may be subject to restrictions on distributions under our new credit facility or other debt agreements entered into in the future. Our new credit facility will contain financial tests and covenants that we must satisfy. These financial tests and covenants are described in "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Our Credit Facility." Should we be unable to satisfy these restrictions or if we are otherwise in default under our new credit facility, we will be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy.

- Our general partner will have the authority to establish reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those reserves could result in a reduction in cash distributions to our unitholders from the levels we currently anticipate pursuant to our stated cash distribution policy. Our partnership agreement does not set a limit on the amount of cash reserves that our general partner may establish. Any determination to establish cash reserves made by our general partner in good faith will be binding on our unitholders. Our partnership agreement provides that in order for a determination by our general partner to be considered to have been made in good faith, our general partner must subjectively believe that the determination is in our best interests.

- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the 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 our public common unitholders other than in certain limited circumstances where no unitholder approval is required. However, our

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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 Holdings) after the subordination period has ended. At the closing of this offering, assuming no exercise of the underwriters' option to purchase additional common units, Holdings will own our general partner and approximately % of our outstanding common units and 100% of our outstanding subordinated units, or % of our limited partner interests.

Even if our cash distribution policy is not modified or revoked, the amount of cash that we distribute and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

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.

We may lack sufficient cash to pay distributions to our unitholders for a number of reasons, including as a result of increases in our operating or general and administrative expenses, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our general partner will not receive a management fee or other compensation for its management of us. However, under our partnership agreement, we are obligated to reimburse our general partner and its affiliates for all expenses incurred on our behalf. Our partnership agreement provides that our general partner will determine the amount of these reimbursed expenses. For the twelve months ending June 30, 2013, we estimate that these expenses will be approximately $23.9 million, which includes, among other items, compensation expense for all employees required to manage and operate our business.

If we make distributions out of capital surplus, as opposed to operating surplus, any such distributions would constitute a return of capital and would result in a reduction in the minimum quarterly distribution and the target distribution levels. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels." We do not anticipate that we will make any distributions from capital surplus.

Our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations.

Our Ability to Grow is Dependent on Our Ability to Access External Expansion Capital

Because we will distribute all of our available cash to our unitholders, we expect that we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion 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, because we intend to distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion 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, and we do not anticipate there being limitations in our new 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

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result in increased interest expense, which in turn may impact the available cash that we have to distribute to our unitholders.

Our Minimum Quarterly Distribution

Upon the closing of this offering, the board of directors of our general partner will establish a minimum quarterly distribution of $ per unit per quarter, or $ per unit on an annualized basis, to be paid no later than 45 days after the end of each fiscal quarter beginning with the quarter ending , 2012. This equates to an aggregate cash distribution of $ million per quarter, or $ million on an annualized basis, based on the number of common and subordinated units anticipated to be outstanding immediately after the closing of this offering, as well as our 2.0% general partner interest. We will adjust our first distribution for the period from the closing of this offering through , 2012 based on the length of that period. Our ability to make cash distributions equal to the minimum quarterly distribution pursuant to this policy will be subject to the factors described above under " General Limitations on Cash Distributions and Our Ability to Change our Cash Distribution Policy."

To the extent the underwriters exercise their option to purchase additional common units, we will use the net proceeds from that exercise to redeem from Holdings a number of common units equal to the number of common units issued upon such exercise, at a price per common unit equal to the proceeds per common unit before expenses but after deducting underwriting discounts, commissions and structuring fees. Accordingly, the exercise of the underwriters' option will not affect the total number of common units or subordinated units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all units. Please read "Use of Proceeds."

Initially, our general partner will be entitled to 2.0% of all distributions that we make prior to our liquidation. In the future, our general partner's initial 2.0% interest in these distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2.0% general partner interest.

The table below sets forth the number of common and subordinated units and the number of unit equivalents represented by the 2.0% general partner interest that we anticipate will be outstanding immediately following the closing of this offering, and the aggregate distribution amounts payable on those units during the year following the closing of this offering at our minimum quarterly distribution rate of $ per unit per quarter ($ per unit on an annualized basis).

		Minimum Quarterly Distributions	
	Number of Units	One Quarter	Annualized
Public Common Units		$	$
Holdings Units:			
Common Units			
Subordinated Units			
LTIP Participants Common Units			
General Partner Interest			
Total		$	$

The subordination period generally will end and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $ on each outstanding common and subordinated unit and the corresponding distribution on our general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after , 2015. The subordination period will automatically terminate and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $

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(150% of the annualized minimum quarterly distribution) on each outstanding common and subordinated unit and the corresponding distributions on our general partner's 2.0% interest and incentive distribution rights for any four consecutive quarter period ending on or after , 2013; provided that we have paid at least the minimum quarterly distribution from operating surplus on each outstanding common unit and subordinated unit for each quarter in that four-quarter period and the corresponding distribution on our general partner's 2.0% interest. Please read the "Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period."

If we do not pay the minimum quarterly distribution on our common units, our common unitholders will not be entitled to receive such payments in the future except in some circumstances during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units and the corresponding distributions on our general partner's 2.0% interest, we will use this excess available cash to pay any distribution arrearages on the common units related to prior quarters before any cash distribution is made to holders of the subordinated units. Our subordinated units will not accrue arrearages for unpaid quarterly distributions or quarterly distributions less than the minimum quarterly distribution. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period."

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement as described above. We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about the 1st of each such month. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. We will adjust the quarterly distribution for the period from the closing of this offering through , 2012 based on the actual length of the period.

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our annualized minimum quarterly distribution of $ per unit for the twelve months ending June 30, 2013.

In those sections, we present two tables, consisting of:

- "Unaudited Pro Forma Cash Available for Distribution," in which we present the amount of cash we would have had available for distribution on a pro forma basis for our fiscal year ended December 31, 2011, derived from our unaudited pro forma financial data that is included elsewhere in this prospectus, which includes the pro forma effect of the EAI acquisition as if such transaction occurred on January 1, 2011, as adjusted to reflect incremental annual general and administrative expenses associated with being a publicly traded partnership; and

- "Estimated Cash Available for Distribution," which supports our belief that we will be able to generate the sufficient estimated cash available for distribution to pay the minimum quarterly distribution on all units for the twelve months ending June 30, 2013.

Unaudited Pro Forma Cash Available for Distribution for the Year Ended December 31, 2011

If we had completed this offering on January 1, 2011, our unaudited pro forma cash available for distribution would have been approximately $17.1 million for the year ended December 31, 2011. This amount would have been sufficient to pay only % of the aggregate minimum quarterly distribution on our common units during that period, and we would have not been able to pay any distributions on our subordinated units during that period.

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Our unaudited pro forma available cash for the year ended December 31, 2011 includes $2.2 million of incremental annual general and administrative expenses that we expect to incur as a result of becoming a publicly traded partnership. This amount is an estimate, and our general partner will ultimately determine the actual amount of these incremental annual general and administrative expenses to be reimbursed by us in accordance with our partnership agreement. Incremental annual general and administrative expenses related to being a publicly traded partnership include expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees, outside director fees and director and officer insurance expenses. These expenses are not reflected in our or our Predecessor's historical financial statements.

Our estimate of incremental annual general and administrative expenses is based upon currently available information. The adjusted amounts below do not purport to present our results of operations had this offering been completed as of the date indicated. In addition, cash available to pay distributions is primarily a cash accounting concept, while our pro forma financial statements have been prepared on an accrual basis. As a result, you should view the amount of pro forma available cash only as a general indication of the amount of cash available to pay distributions that we might have generated had we completed this offering on the dates indicated.

The following table illustrates, on a pro forma basis, for the year ended December 31, 2011, the amount of cash that would have been available for distribution to our unitholders, assuming that this offering had been completed at the beginning of such period. Each of the adjustments reflected or presented below is explained in the footnotes to such adjustments.

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Unaudited Pro Forma Cash Available for Distribution

	Year Ended December 31, 2011 (in thousands, except per unit data)	
Pro Forma Net Income	$	6,576
Add:		
Depreciation and amortization expense		13,200
Interest expense, net(1)		7,283
Loss on extinguishment of debt		3,240
Transaction costs(2)		203
Income tax expense(3)		261
Pro Forma Adjusted EBITDA(4)	$	30,763
Less:		
Incremental annual general and administrative expenses of being a publicly traded partnership(5)		2,200
Cash interest expense, net of interest income(6)		6,366
Cash tax expense		272
Expansion capital expenditures(7)		139,807
Maintenance capital expenditures(8)		5,423
Add:		
Management fee(9)		600
Borrowings to fund expansion capital expenditures		139,807
Pro Forma Cash Available for Distribution	$	17,102
Implied Cash Distribution at the Minimum Quarterly Distribution Rate:		
Annualized minimum quarterly distribution per unit	$	
Distributions to public common unitholders		
Distributions to Holdings common units		
Distributions to Holdings subordinated units		
Distributions to LTIP participants		
Distributions to general partner		
Total distributions to unitholders and general partner	$	
Excess (shortfall)	$	
Percent of minimum quarterly distribution payable to common unitholders		
Percent of minimum quarterly distribution payable to subordinated unitholders		

(1) Represents interest expense at the interest rate of 4.0% on the outstanding debt balance of $180.0 million as though we entered into our new credit facility on January 1, 2011 plus applicable commitment and deferred financing fees.

(2) Represents costs relating to the acquisition of EAI on September 1, 2011.

(3) Represents Texas state tax on gross margin.

(4) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures," and for a discussion of how we use Adjusted EBITDA to evaluate our operating performance, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations."

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(5)
Represents estimated cash expense associated with being a publicly traded partnership, such as expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees, outside director fees and director and officer insurance expenses.

(6)
Pro forma cash interest paid was reduced by $1.8 million to eliminate the impact of a payment in early January 2011 for interest expense incurred in 2010, and reflects four quarters of cash interest expense, net of interest income.

(7)
Expansion capital expenditures include the acquisition of equipment, or the construction, development or acquisition of additional pipeline or treating capacity or compression capacity to the extent that such capital expenditures are expected to expand our long-term operating capacity or operating income. Expansion capital expenditures have been adjusted by a decrease of $10.9 million, which represents amounts outstanding in accounts payable as of December 31, 2011.

(8)
Maintenance capital expenditures are made to maintain our long-term operating income or operating capacity. We expect that a primary component of maintenance capital expenditures will include expenditures for routine equipment and pipeline maintenance or replacement due to obsolescence.

(9)
Represents a fee paid to Charlesbank that will no longer be paid when we become a publicly traded partnership.

Estimated Cash Available for Distribution for the Twelve Months Ending June 30, 2013

We forecast that our estimated cash available for distribution for the twelve months ending June 30, 2013 will be approximately $48.0 million. This amount would exceed by $ million the amount needed to pay the total annualized minimum quarterly distribution of $ on all of our common and subordinated units, as well as the corresponding distribution on our 2.0% general partner interest, for the twelve months ending June 30, 2013.

We do not, as a matter of course, make public projections as to future operations, earnings or other results. However, management has prepared the forecast of estimated cash available for distribution and related assumptions and considerations set forth below to substantiate our belief that we will have sufficient cash available for distribution to allow us to pay the total annualized minimum quarterly distribution on all of our outstanding common and subordinated units as well as the corresponding distribution on our 2.0% general partner interest, for the twelve months ending June 30, 2013. This forecast is a forward-looking statement and should be read together with our historical consolidated financial statements and the accompanying notes, and our Predecessor's historical combined financial statements and the accompanying notes included elsewhere in this prospectus, as well as "Management's Discussion and Analysis of Financial Condition and Results of Operations." The accompanying prospective financial information was not prepared with a view toward complying with the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, is substantially consistent with those guidelines and was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the assumptions on which we base our belief that we can generate the minimum estimated cash available for distribution necessary to pay the total annualized minimum quarterly distribution on all of our outstanding common and subordinated units, as well as the corresponding distribution on our 2.0% general partner interest, for the twelve months ending June 30, 2013. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

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The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, our management. Neither our independent registered public accounting firm nor any other independent accountants have compiled, examined, or performed any procedures with respect to the prospective financial information contained herein, nor have they expressed any opinion or any other form of assurance on such information or its achievability. They therefore assume no responsibility for, and disclaim any association with, the prospective financial information. The reports of our independent registered public accounting firm included in this prospectus relate to our and our Predecessor's historical financial information, and those reports do not extend to the prospective financial information and should not be read to do so.

When considering our financial forecast, you should keep in mind the risk factors and other cautionary statements under "Risk Factors." Any of the risks discussed in this prospectus, to the extent they are realized, could cause our actual results of operations to vary significantly from those that would enable us to generate the minimum estimated cash available for distribution necessary to pay the total annualized minimum quarterly distribution on all of our outstanding common and subordinated units, as well as the corresponding distribution on our 2.0% general partner interest, for the twelve months ending June 30, 2013.

We are providing the forecast of estimated cash available for distribution and related assumptions set forth below to supplement our historical consolidated financial statements and our Predecessor's historical combined financial statements in support of our belief that we will have sufficient cash available for distribution to allow us to pay the total annualized minimum quarterly distribution on all of our outstanding common and subordinated units, as well as the corresponding distribution on our 2.0% general partner interest, for the twelve months ending June 30, 2013. Please read below under " Assumptions and Considerations" for further information as to the assumptions we have made for the financial forecast.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update this financial forecast to reflect events or circumstances after the date of this prospectus. Therefore, the statement that we believe that we will have sufficient cash available for distribution to allow us to pay the total annualized minimum quarterly distribution on all of our outstanding common and subordinated units, as well as the corresponding distribution on our 2.0% general partner interest for the twelve months ending June 30, 2013 should not be regarded as a representation by us, the underwriters or any other person that we will make such distributions. Therefore, you are cautioned not to place undue reliance on this information.

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Estimated Cash Available For Distribution

		Twelve Months Ending June 30, 2013 (in thousands, except per unit data)
Total Revenue	$	749,387
Expenses:		
Cost of natural gas and liquids sold		637,467
Operations and maintenance		38,285
Depreciation and amortization		22,106
General and administrative(1)		12,094
Total expenses		709,952
Income from operations		39,435
Interest expense, net		(8,253)
Income tax expense(2)		(515)
Net income	$	30,667
Plus:		
Depreciation and amortization		22,106
Interest expense, net		8,253
Income tax expense(2)		515
Adjusted EBITDA(3)		61,541
Less:		
Cash interest expense, net of interest income		(7,355)
Cash tax expense		(515)
Expansion capital expenditures(4)		(43,965)
Maintenance capital expenditures(5)		(5,700)
Add:		
Available cash and borrowings to fund expansion capital expenditures		43,965
Estimated cash available for distribution	$	47,971
Implied cash distribution at the minimum quarterly distribution rate:		
Annualized minimum quarterly distribution per unit		
Distributions to public common unit holders		
Distributions to Holdings common units		
Distributions to Holdings subordinated units		
Distributions to LTIP participants		
Distributions to general partner		
Total distribution to our unitholders and general partner	$	
Excess of cash available for distribution over total annualized minimum quarterly distributions	$	

(1) Includes $2.2 million of estimated incremental annual cash expense associated with being a publicly traded partnership, such as expenses associated with annual and quarterly reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance expenses; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; outside director fees and director and officer insurance expenses.

(2) Represents Texas state tax on gross margin.

(3) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures," and for a discussion of how we use Adjusted EBITDA to evaluate our operating performance, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations."

(4) Expansion capital expenditures include the acquisition of equipment, or the construction, development or acquisition of additional pipeline or treating capacity or compression capacity to the extent that such capital expenditures are expected to expand our long-term operating capacity or operating income. Expansion capital expenditures have been adjusted by an increase of $11.0 million, which represents estimated amounts outstanding in accounts payable as of June 30, 2012 that will be paid during the forecast period.

(5) Maintenance capital expenditures are made to maintain our long-term operating income or operating capacity. We expect that a primary component of maintenance capital expenditures will include expenditures for routine equipment and pipeline maintenance or replacement due to obsolescence.

Assumptions and Considerations

Set forth below are the material assumptions that we have made in order to demonstrate our ability to generate the minimum estimated cash available for distribution to pay the total annualized minimum quarterly distribution to all unitholders for the twelve months ending June 30, 2013.

General considerations and sensitivity analysis

We currently expect that opportunities to process liquids-rich natural gas in the Eagle Ford shale area, which is served by our South Texas assets, will be the primary driver of our near-term growth. We have completed the construction of and are commencing operations at our Woodsboro cryogenic processing plant. In addition, we are expanding our NGL capacity by installing our Bonnie View fractionator, an 11,500 Bbl/d fractionation facility that we expect to be fully operational in August 2012. These two projects, in combination with other recently completed growth projects, are expected to significantly improve our ability to process liquids-rich natural gas and fractionate NGLs for sale in the Eagle Ford shale area. Accordingly, our forecasted results are not directly comparable with historical periods. Processing and fractionation capacity that we expect to come on-line at Woodsboro and Bonnie View should enable us to extract more economic value than we can currently achieve from contracts with third party providers. The increased capacities are expected to eliminate the limitations that reduced our ability to produce and sell NGLs during the year ended December 31, 2011.

This forecast for the twelve months ending June 30, 2013 anticipates that our natural gas supply will come from existing contracts or from new supply contracts that we expect to enter into. We are aware of certain producers under contract that expect to increase their volumes and this has been included in the forecast. This forecast will also include twelve months operational results from the EAI acquisition and a full year's benefit from our McMullen pipeline expansion.

We estimate that our realized price of natural gas and NGLs for the twelve months ending June 30, 2013 will average $3.24 per MMBtu and $1.15 per gallon, respectively, and represent a decrease of 20.0% and 15.1%, respectively, over the prices that we realized during the year ended December 31, 2011. These estimates for the realized price of natural gas and NGLs were derived based upon forward NYMEX natural gas prices as of March 1, 2012 and management's internal estimates for NGL prices, respectively, as adjusted for various discounts or premiums to reflect transportation, quality and regional price adjustments.

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System throughput volumes and natural gas and NGL prices are the key factors that will influence whether the amount of cash available for distribution for the twelve months ending June 30, 2013 is above or below our forecast. For example, if all other assumptions are held constant, a five percent (5.0%) increase or decrease in volumes across all of our assets above or below forecasted levels would result in a $4.4 million increase or $4.1 million decrease, respectively, in cash available for distribution. A five percent (5.0%) increase or decrease in the price of natural gas above or below forecasted levels would result in a $0.4 million decrease or $0.4 million increase, respectively, in cash available for distribution. This inverse relationship between an increase in natural gas prices and the resulting decrease in cash available for distribution is due to the fact that the negative impact on our processing margins from an increase in natural gas prices outweighs the positive impact on our margins from sales of residue natural gas. This is due in part to the fact that a significant portion of our contracts are fixed fee or fixed spread, which serves to mitigate the impact of changes in natural gas prices on our results. A five percent (5.0%) decrease in the price of NGLs below forecasted levels, would result in a $2.2 million decrease in cash available for distribution. A five percent (5.0%) increase in the price of NGLs above forecasted levels, would result in a $2.2 million increase in cash available for distribution. A decrease in forecasted cash flow of greater than $ million would result in our generating less than the minimum cash required to pay distributions during the forecast period.

Throughput and processing volumes

We forecast that our average throughput of natural gas per day will be 747,075 MMBtu and that we will deliver an average daily volume of 707.3 Mgal of NGLs for the twelve months ending June 30, 2013, compared to an average daily volume of 506,975 MMBtu and added 215.5 Mgal, respectively, for the year ended December 31, 2011.

The expected total increase in natural gas throughput is 240,100 MMBtu per day, which represents growth of 47.4% over the year ended December 31, 2011. Of the 47.4% increase in natural gas throughput, (i) 34.9% (177,168 MMBtu) is due to the impact of Eagle Ford shale area volumes, particularly the impact of twelve months of throughput on our McMullen pipeline extension into the Eagle Ford shale area, compared to only three months in the year ended December 31, 2011; (ii) 14.7% (74,482 MMBtu) is due to the benefit of twelve months of volumes attributable to the EAI acquisition as opposed to only four months in the year ended December 31, 2011; and (iii) a 2.2% (11,550 MMBtu) decrease is due to our assumption that our supply in areas utilizing conventional drilling in Mississippi, Alabama and South Texas will show a slight decline in volume for the forecast compared to the year ended December 31, 2011.

The table below outlines the components of our estimated and actual NGL volumes for the twelve months ending June 30, 2013 and the year ended December 31, 2011.

	Average Daily Volumes of NGLs Delivered (in Mgal)	
	Historical Year Ended December 31, 2011	Forecasted Twelve Months Ending June 30, 2013
Woodsboro processing plant		510.2
Existing facilities (including Formosa)	215.5	197.1
Total	215.5	707.3

Our average volume of NGLs delivered per day is forecasted to be 707.3 Mgal for the twelve months ending June 30, 2013, an increase of 228.8% compared to 215.5 Mgal for the year ended December 31, 2011. This significant increase will be driven primarily by four factors: (i) the completion of our new Woodsboro facility, which will provide us with greater processing capacity; (ii) new sources of gas from the Eagle Ford shale area that we expect to be processed utilizing this additional capacity

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at Woodsboro; (iii) greater processing efficiencies arising from the Woodsboro facility together with the Bonnie View fractionator as compared to the existing capabilities at our Gregory plant or the contracted Formosa plant; and (iv) incremental NGL volumes from existing sources of gas that will be transferred from the Formosa plant, where we have a sharing agreement for NGLs that will expire in January 2013, to our Woodsboro plant where we will realize a larger volume of NGLs produced. We also expect to benefit from a reduction in downtime associated with closures of processing facilities in the forecast compared to the year ended December 31, 2011.

Revenue

We estimate that we will generate total revenue of $749.4 million for the twelve months ending June 30, 2013, compared to $523.1 million for the year ended December 31, 2011. This increase primarily relates to higher expected natural gas and NGL volumes, offset partially by lower natural gas, NGL and condensate prices on our systems as described above. Please read " Gross operating margin."

Cost of natural gas and NGLs sold

We estimate that the cost of natural gas and NGLs sold for the twelve months ending June 30, 2013 will be $637.5 million, compared to $460.6 million for the year ended December 31, 2011. The expected increase is primarily due to expected higher natural gas and NGL volumes on our systems, partially offset by lower natural gas, NGL and condensate prices, as further described in the tables above. We purchase natural gas and NGLs at market prices adjusted for transportation, quality and regional price differentials.

Gross operating margin

We estimate that we will generate gross operating margin of $111.9 million for the twelve months ending June 30, 2013, compared to $62.6 million for the year ended December 31, 2011. The table below outlines the components of our estimated and actual gross operating margin for the twelve months ending June 30, 2013 and the year ended December 31, 2011.

	Year Ended December 31, 2011		Forecasted Twelve Months Ending June 30, 2013	
	Gross operating margin (in thousands)	Percent of total gross operating margin	Gross operating margin (in thousands)	Percent of total gross operating margin
Fixed-fee	$ 32,340	51.7%	$ 55,680	49.7%
Fixed-spread	12,204	19.6	14,534	13.0
POP floor(1)	2,340	3.7	893	0.8
Sub-total	$ 46,884	75.0%	$ 71,107	63.5%
POP	4,339	6.9	31,953	28.5
POP upgrade(2)	11,346	18.1	8,860	7.9
Total	$ 62,569	100%	$ 111,920	100%

(1) Represents that portion of gross operating margin under the processing arrangement with Formosa that is derived on a fixed-spread basis. For more information about our contract with Formosa, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Our Operations Percent-of-Proceeds."

(2) Represents that portion of gross operating margin under the processing arrangement with Formosa that is derived from a fixed percentage of the value of the NGLs delivered and the residue gas. This margin will vary with the relative prices of NGLs and natural gas and is not realized when the price of NGLs is low relative to the price of natural gas.

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We estimate that our forecasted increase of 47.4% in natural gas volumes for the twelve months ending June 30, 2013, compared to the year ended December 31, 2011, will result in higher fixed fee margins of $55.7 million for the forecast period compared to $32.3 million for the year ended December 31, 2011. As we bring the Woodsboro processing plant online, we expect to increase both absolute margins and the percentage contribution of our processing contracts to our total margin. As the volume at our Woodsboro processing plant increases, we will reduce the amount of natural gas sent to Formosa for processing and, therefore, reduce the margins related to our Formosa contract (POP floor and POP upgrade) and increase our POP margins. Our ability to process more gas through our Woodsboro processing plant, the retention of a greater portion of the processing margins in 2013 from our NGL production and the impact of the Bonnie View fractionator underlie our expectation of POP margins of $32.0 million for the twelve months ending June 30, 2013, compared to $4.3 million for the year ended December 31, 2011. If the Formosa contract were to expire as of June 30, 2012 instead of January 2013 and we processed all of the natural gas previously destined for Formosa at our Woodsboro processing plant throughout the forecast period, we estimate that our gross margin for the forecast period would increase by $6.9 million. As we bring additional new supplies of natural gas to our Woodsboro processing plant by adding pipeline capacity during the forecast period, we expect to increase both our fixed fee and POP margins.

Operations and maintenance expense

We forecast operations and maintenance expenses of $38.3 million for the forecast period compared with $24.7 million for the year ended December 31, 2011. We anticipate continuation of our historical level of these expenses, adjusted for inflation, in the forecast period, with added expenses for incremental assets.

	Historical Year Ended December 31, 2011	Forecasted Twelve Months Ending June 30, 2013
	(in thousands)	
Woodsboro processing plant	$	$ 6,416
Bonnie View fractionator		2,250
EAI acquisition	1,228	3,779
Other	23,479	25,840
Total	$ 24,707	$ 38,285

General and administrative expense

We estimate that G&A expense for the twelve months ending June 30, 2013 will be $12.1 million, compared to $8.9 million for the year ended December 31, 2011. This increase will be primarily attributable to the estimated $2.2 million of incremental annual G&A expense that we expect to incur as a result of being a publicly traded partnership. G&A expense is comprised primarily of fixed costs and is not expected to vary significantly with increases or decreases in revenue or gross margin except for variable performance-based compensation programs. G&A expense for the year ended December 31, 2011 includes a management fee of $50,000 per month that we paid to Charlesbank. Following the completion of this offering, we will no longer be required to pay this fee to Charlesbank.

Depreciation and amortization expense

We estimate that depreciation and amortization expense for the twelve months ending June 30, 2013 will be $22.1 million compared to $12.3 million for the year ended December 31, 2011. Estimated depreciation expense is based on average depreciable asset lives and depreciation methodologies consistent with our historical practice. The increase in depreciation expense will be primarily attributable to additional depreciation associated with capital projects that were completed in 2011 or that we expect to be placed in service during 2012. Depreciation expenses are derived from asset value and useful life, and therefore will not vary with increases or decreases in revenue and gross margin.

Capital expenditures

We estimate that total capital expenditures for the twelve months ending June 30, 2013 will be $38.7 million compared to $156.0 million for the year ended December 31, 2011. Our estimate is based on the following assumptions:

- We estimate that maintenance capital expenditures for the twelve months ending June 30, 2013 will total $5.7 million, compared to $5.3 million for the year ended December 31, 2011. These expenditures include planned maintenance on our systems.

- We estimate that growth capital expenditures for the twelve months ending June 30, 2013 will be $33.0 million, compared to $150.7 million for the year ended December 31, 2011. These expenditures are comprised of growth capital projects that we anticipate pursuing during the forecast period. Once fully in service, we expect that these projects will add $7.8 million in gross margin on an annualized basis, of which $4.4 million in gross margin is reflected in this forecast. The capital projects that we expect to undertake in our forecast period include:

  - constructing 21 miles of new pipeline to bring additional supply from DeWitt and Karnes counties in the Eagle Ford shale area to our Woodsboro processing plant;

  - constructing a dry gas line near Petronila, Texas to enhance deliveries to the Corpus Christi area;

  - increasing the capacity of our Bonnie View fractionator; and

  - adding compression to our South Texas system in order to increase natural gas throughput to our Woodsboro processing plant.

Financing

We estimate that interest expense will be approximately $8.3 million (including approximately $0.9 million in non-cash interest expense related to deferred financing fees) for the twelve months ending June 30, 2013, compared to approximately $5.4 million for the year ended December 31, 2011. Our estimate of interest expense for the forecast period is based on the following assumptions:

- We will have debt outstanding under our new credit facility as of the closing of this offering of $180.0 million; and

- We will have average outstanding borrowings during the forecast period of $205.6 million, including borrowings to finance our expansion capital expenditures, with an assumed weighted average interest rate of 4.0%.

Regulatory, Industry and Economic Factors

Our forecast for the twelve months ending June 30, 2013 is based on the following significant assumptions related to regulatory, industry and economic factors:

- There will not be any new federal, state or local regulation of the midstream energy sector, or any new interpretation of existing regulations, that will be materially adverse to our business.

There will not be any major adverse change in the midstream energy sector, commodity prices, capital or insurance markets or general economic conditions.

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PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending , 2012, we distribute all of our available cash to unitholders of record on the applicable record date. We will adjust the minimum quarterly distribution for the period from the closing of the offering through , 2012 based on the actual length of the period.

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; and
  - 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 common and subordinated units 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 and the next four quarters);
- 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.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Under our partnership agreement, working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners, and with the intent of the borrower to repay such borrowings within 12 months with funds other than from additional working capital borrowings. The proceeds of working capital borrowings increase operating surplus and repayments of working capital borrowings are generally operating expenditures (as described below) and thus reduce operating surplus when repayments are made. However, if working capital borrowings, which increase operating surplus, are not repaid during the 12-month period following the borrowing, they will be deemed repaid at the end of such period, thus decreasing operating surplus at such time. When such working capital borrowings are in fact repaid, they will not be treated as a further reduction in operating surplus because operating surplus will have been previously reduced by the deemed repayment.

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Intent to Distribute the Minimum Quarterly Distribution

We intend to make a minimum quarterly distribution to the holders of our common units and subordinated units of $ per unit, or $ on an annualized basis, to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. 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. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Our Credit Facility" for a discussion of the restrictions to be included in our new credit facility that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights

Initially, our general partner will be 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 50.0%, of the cash we distribute from operating surplus (as defined below) in excess of $ per unit per quarter. The maximum distribution of 50.0% 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 50.0% does not include any distributions that our general partner may receive on any limited partner units that it owns. Please see " General Partner Interest and Incentive Distribution Rights" for additional information.

Operating Surplus and Capital Surplus

General

All cash distributed to unitholders will be characterized as either being paid from "operating surplus" or "capital surplus." We treat distributions of available cash from operating surplus differently than distributions of available cash from capital surplus.

Operating Surplus We define operating surplus as:

- $ million (as described below); *plus*

- all of our cash receipts after the closing of this offering, excluding cash from interim capital transactions (as defined below); *plus*

- working capital borrowings made after the end of a quarter but on or before the date of determination of operating surplus for that quarter; *plus*

- cash distributions paid on equity issued (including incremental distributions on incentive distribution rights) to finance all or a portion of the construction, acquisition, development or improvement of a capital improvement or replacement of a capital asset (such as equipment or facilities) in respect of the period beginning on the date that we enter into a binding obligation to commence the construction, acquisition, development or improvement of a capital improvement or replacement of a capital asset and ending on the earlier to occur of the date

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the capital improvement or capital asset commences commercial service and the date that it is abandoned or disposed of; *plus*

cash distributions paid on equity issued to pay the construction-period interest on debt incurred, or to pay construction-period distributions on equity issued, to finance the capital improvements or capital assets referred to above; *less*

all of our operating expenditures (as defined below) after the closing of this offering; *less*

the amount of cash reserves established by our general partner to provide funds for future operating expenditures; *less*

all working capital borrowings not repaid within 12 months after having been incurred, or repaid within such 12-month period with the proceeds of additional working capital borrowings; *less*

any cash loss realized on disposition of an investment capital expenditure.

As described above, operating surplus does not reflect actual cash on hand that is available for distribution to our unitholders and is not limited to cash generated by operations. For example, it includes a provision that will enable us, if we choose, to distribute as operating surplus up to $ million of cash we receive in the future from non-operating sources such as asset sales, issuances of securities and long-term borrowings that would otherwise be distributed as capital surplus. In addition, the effect of including, as described above, certain cash distributions on equity interests in operating surplus will be to increase operating surplus by the amount of any such cash distributions. As a result, we may also distribute as operating surplus up to the amount of any such cash that we receive from non-operating sources.

We define interim capital transactions as (i) borrowings, refinancings or refundings of indebtedness (other than working capital borrowings and items purchased on open account in the ordinary course of business) and sales of debt securities, (ii) sales of equity securities, (iii) sales or other dispositions of assets, other than sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business and sales or other dispositions of assets as part of ordinary course asset retirements or replacements, (iv) the termination of commodity hedge contracts or interest rate hedge contracts prior to the termination date specified therein (provided that cash receipts from any such termination will be included in operating surplus in equal quarterly installments over the remaining scheduled life of the contract), (v) capital contributions received and (vi) corporate reorganizations or restructurings.

We define operating expenditures as all of our cash expenditures, including, but not limited to, taxes, reimbursements of expenses to our general partner, interest payments, payments made in the ordinary course of business under interest rate hedge contracts and commodity hedge contracts (provided that (i) with respect to amounts paid in connection with the initial purchase of an interest rate hedge contract or a commodity hedge contract, such amounts will be amortized over the life of the applicable interest rate hedge contract or commodity hedge contract and (ii) payments made in connection with the termination of any interest rate hedge contract or commodity hedge contract prior to the expiration of its stipulated settlement or termination date will be included in operating expenditures in equal quarterly installments over the remaining scheduled life of such interest rate hedge contract or commodity hedge contract), director and officer compensation, repayment of working capital borrowings and non-pro rata repurchases of our units; *provided*, *however*, that operating expenditures will not include:

repayments of working capital borrowings where such borrowings have previously been deemed to have been repaid (as described above);

payments (including prepayments and prepayment penalties) of principal of and premium on indebtedness other than working capital borrowings;

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- expansion capital expenditures;
- investment capital expenditures;
- payment of transaction expenses (including, but not limited to, taxes) relating to interim capital transactions;
- distributions to our partners; or
- non-pro rata purchases of any class of our units made with the proceeds of an interim capital transaction.

Capital Surplus Capital surplus is defined in our partnership agreement as any distribution of available cash in excess of our cumulative operating surplus. Accordingly, except as described above, capital surplus would generally be generated by:

- borrowings other than working capital borrowings;
- sales of our equity and debt securities; and
- sales or other dispositions of assets, other than inventory, accounts receivable and other assets sold in the ordinary course of business or as part of ordinary course retirement or replacement of assets.

Characterization of Cash Distributions

Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since the closing of this offering equals the operating surplus from the closing of this offering through the end of the quarter immediately preceding that distribution. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Capital Expenditures

Maintenance capital expenditures are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity. We expect that a primary component of maintenance capital expenditures will include expenditures for routine equipment and pipeline maintenance or replacement due to obsolescence. Maintenance capital expenditures will also include interest (and related fees) on debt incurred and distributions on equity issued (including incremental distributions on incentive distribution rights) to finance all or any portion of the construction or development of a replacement asset that is paid in respect of the period that begins when we enter into a binding obligation to commence constructing or developing a replacement asset and ending on the earlier to occur of the date that any such replacement asset commences commercial service and the date that it is abandoned or disposed of.

Expansion capital expenditures are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term. Expansion capital expenditures include interest payments (and related fees) on debt incurred and distributions on equity issued to finance the construction of such capital improvement and paid in respect of the period beginning on the date that we enter into a binding obligation to commence construction of the capital improvement and ending on the earlier to occur of the date that such capital improvement commences commercial service and the date that such capital improvement is abandoned or disposed of. Examples of expansion capital expenditures include the acquisition of equipment, or the

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construction, development or acquisition of additional pipeline or treating capacity or new compression capacity, to the extent such capital expenditures are expected to expand our long-term operating capacity or operating income.

Investment capital expenditures are those capital expenditures that are neither maintenance capital expenditures nor expansion capital expenditures. Investment capital expenditures largely will consist of capital expenditures made for investment purposes. Examples of investment capital expenditures include traditional capital expenditures for investment purposes, such as purchases of securities, as well as other capital expenditures that might be made in lieu of such traditional investment capital expenditures, such as the acquisition of a capital asset for investment purposes or development of facilities that are in excess of the maintenance of our existing operating capacity or operating income, but that are not expected to expand, for more than the short term, our operating capacity or operating income.

Capital expenditures that are made in part for maintenance capital purposes, expansion capital purposes and/or investment capital purposes will be allocated as maintenance capital expenditures, expansion capital expenditures or investment capital expenditures by our general partner (with the concurrence of the Conflicts Committee).

Subordination Period

General

Our partnership agreement provides that, during the subordination period (which we define below), the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $ per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units.

Subordination Period

Except as described below, the subordination period will begin on the closing date of this offering and will extend until the first business day of any quarter beginning after , 2015 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common and subordinated units equaled or exceeded $ (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the adjusted operating surplus (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded (i) the sum of $ (the annualized minimum quarterly distribution) on all of the outstanding common and subordinated units during those periods on a fully diluted weighted average basis and (ii) the corresponding distribution on our 2.0% general partner interest; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early Termination of Subordination Period

Notwithstanding the foregoing, the subordination period will automatically terminate on the first business day of any quarter beginning after , 2013 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded $ (150.0% of the annualized minimum quarterly distribution) for the four-quarter period immediately preceding that date;

- the adjusted operating surplus (as defined below) generated during the four-quarter period immediately preceding that date equaled or exceeded the sum of (i) $ (150.0% of the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during that period on a fully diluted weighted average basis and (ii) the distributions made on our 2.0% general partner interest and the incentive distribution rights;

- distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the minimum quarterly distribution of $ per unit, and we made the corresponding distribution on our 2.0% general partner interest, for each quarter during the four-quarter period immediately preceding that date; and

- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Expiration of the Subordination Period

When the subordination period ends, each outstanding subordinated unit will convert into one common unit and will thereafter participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and no units held by our general partner and its affiliates are voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately and automatically convert into one common unit;

- any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Definition of Adjusted Operating Surplus

Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net increases in working capital borrowings and net drawdowns of reserves of cash established in prior periods. Adjusted operating surplus for a period consists of:

- operating surplus generated with respect to that period (excluding any amounts attributable to the item described in the first bullet point under the caption " Operating Surplus and Capital Surplus Operating Surplus" above); *less*

- any net increase in working capital borrowings with respect to that period; *less*

- any net decrease in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; *plus* any net decrease in working capital borrowings with respect to that period; *plus*

- any net decrease made in subsequent periods to cash reserves for operating expenditures initially established with respect to that period to the extent such decrease results in a reduction in adjusted operating surplus in subsequent periods pursuant to the third bullet point above; *plus*

- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Distributions of Available Cash from Operating Surplus during the Subordination Period

We will make distributions of available cash from operating surplus for any quarter during the subordination period in the following manner:

- *first*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;

- *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

- *third*, 98.0% to the subordinated unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, in the manner described in " General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

Distributions of Available Cash from Operating Surplus after the Subordination Period

We will make distributions of available cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and

- *thereafter*, in the manner described in " General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner initially will be 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 in order to maintain its 2.0% general partner interest if we issue additional units. Our general partner's 2.0% interest, and the percentage of our cash distributions to which it is entitled from such 2.0% interest, will be proportionately reduced if we issue additional units in the future (other than the issuance of common units upon exercise by the underwriters of their option to purchase additional common units, the issuance of common units upon conversion of outstanding subordinated units or the issuance of common units upon a reset of the incentive distribution rights) and our general partner does not contribute a proportionate amount of

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capital to us in order to maintain its 2.0% general partner interest. Our partnership agreement does not require that our general partner fund its capital contribution with cash. It may instead fund its capital contribution by the contribution to us of common units or other property.

Incentive distribution rights represent the right to receive an increasing percentage (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

The following discussion assumes that our general partner maintains its 2.0% general partner interest, that there are no arrearages on common units and that our general partner continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives a total of $ per unit for that quarter (the "first target distribution");
- *second*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives a total of $ per unit for that quarter (the "second target distribution");
- *third*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives a total of $ per unit for that quarter (the "third target distribution"); and
- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

Percentage Allocations of Available Cash from Operating Surplus

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

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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.

	Total Quarterly Distribution Per Unit Target Amount		Marginal Percentage Interest in Distributions Unitholders	General Partner
Minimum Quarterly Distribution		$	98.0%	2.0%
First Target Distribution		up to $	98.0%	2.0%
Second Target Distribution	above $	up to $	85.0%	15.0%
Third Target Distribution	above $	up to $	75.0%	25.0%
Thereafter		above $	50.0%	50.0%

General Partner's Right to Reset Incentive Distribution Levels

Our general partner, as the initial holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and target distribution levels upon which the incentive distribution payments to our general partner would be set. If our general partner transfers all or a portion of our incentive distribution rights in the future, then the holder or holders of a majority of our incentive distribution rights will be entitled to exercise this right. The following discussion assumes that our general partner holds all of the incentive distribution rights at the time that a reset election is made. Our general partner's right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are based may be exercised, without approval of our unitholders or the Conflicts Committee, at any time when there are no subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the four consecutive fiscal quarters immediately preceding such time. If our general partner and its affiliates are not the holders of a majority of the incentive distribution rights at the time an election is made to reset the minimum quarterly distribution amount and the target distribution levels, then the proposed reset will be subject to the prior written concurrence of the general partner that the conditions described above have been satisfied. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target distributions prior to the reset, our general partner will be entitled to receive a number of newly issued common units and general partner units based on a predetermined formula described below that takes into account the "cash parity" value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters immediately preceding the reset event as compared to the average cash distributions per common unit during that two-quarter period. Our general partner will be issued the number of general partner units necessary to maintain our general partner's interest in us immediately prior to the reset election.

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The number of common units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to the quotient determined by dividing (x) the average aggregate amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election by (y) the average of the amount of cash distributed per common unit during each of these two quarters.

Following a reset election, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per unit for the two fiscal quarters immediately preceding the reset election (which amount we refer to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to be correspondingly higher such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until each unitholder receives an amount equal to 115.0% of the reset minimum quarterly distribution for that quarter;

- *second*, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until each unitholder receives an amount per unit equal to 125.0% of the reset minimum quarterly distribution for the quarter;

- *third*, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until each unitholder receives an amount per unit equal to 150.0% of the reset minimum quarterly distribution for the quarter; and

- *thereafter*, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

The following table illustrates the percentage allocation of available cash from operating surplus between the unitholders and our general partner at various cash distribution levels (i) pursuant to the cash distribution provisions of our partnership agreement in effect at the closing of this offering, as well as (ii) following a hypothetical reset of the minimum quarterly distribution and target distribution levels based on the assumption that the average quarterly cash distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $.

	Quarterly Distribution per Unit Prior to Reset		Marginal Percentage Interest In Distributions: Unitholders	2% General Partner Interest	Incentive Distribution Rights	Quarterly Distributions per Unit Following Hypothetical Reset	
Minimum Quarterly Distribution		$	98.0%	2.0%		$	
First Target Distribution		up to $	98.0%	2.0%		up to $	(1)
Second Target Distribution	above $	up to $	85.0%	2.0%	13.0%	above $ up to $	(1), (2)
Third Target Distribution	above $	up to $	75.0%	2.0%	23.0%	above $ up to $	(2), (3)
Thereafter		above $	50.0%	2.0%	48.0%	above $	(3)

(1) This amount is 115.0% of the hypothetical reset minimum quarterly distribution.

(2) This amount is 125.0% of the hypothetical reset minimum quarterly distribution.

(3)

This amount is 150.0% of the hypothetical reset minimum quarterly distribution.

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner, including in respect of incentive distribution rights, based on an average of the amounts distributed each quarter for the two quarters immediately

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prior to the reset. The table assumes that immediately prior to the reset there would be common units outstanding, our general partner has maintained its 2.0% general partner interest and the average distribution to each common unit would be $ for the two quarters prior to the reset.

	Quarterly Distribution per Unit Prior to Reset		Cash Distributions to Common Unitholders Prior to Reset	Cash Distribution To General Partner Prior To Reset 2% General Partner Interest	Incentive Distribution Rights	Total	Total Distributions
Minimum Quarterly Distribution		$					
First Target Distribution		up to $					
Second Target Distribution	above $	up to $					
Third Target Distribution	above $	up to $					
Thereafter		above $					

The following table illustrates the total amount of available cash from operating surplus that would be distributed to the unitholders and our general partner, including in respect of incentive distribution rights, with respect to the quarter in which the reset occurs. The table reflects that, as a result of the reset, there would be common units outstanding, our general partner's 2.0% interest has been maintained, and the average distribution to each common unit would be $. The number of common units to be issued to our general partner upon the reset was calculated by dividing (i) the average of the amounts received by our general partner in respect of its incentive distribution rights for the two quarters prior to the reset as shown in the table above, or $, by (ii) the average available cash distributed on each common unit for the two quarters prior to the reset as shown in the table above, or $.

	Quarterly Distribution per Unit After Reset		Cash Distributions to Common Unitholders After Reset	Cash Distribution To General Partner After Reset 2% General Partner Interest	Incentive Distribution Rights	Total	Total Distributions
Minimum Quarterly Distribution		$					
First Target Distribution		up to $					
Second Target Distribution	above $	up to $					
Third Target Distribution	above $	up to $					
Thereafter		above $					

Our general partner will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the immediately preceding four consecutive fiscal quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement.

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Distributions from Capital Surplus

How Distributions from Capital Surplus Will Be Made

We will make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we distribute for each common unit that was issued in this offering, an amount of available cash from capital surplus equal to the initial public offering price in this offering;

- *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

- *thereafter*, as if they were from operating surplus.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

Effect of a Distribution from Capital Surplus

Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the "unrecovered initial unit price." Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution and target distribution levels after any of these distributions are made, it may be easier for our general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we distribute capital surplus on a unit issued in this offering in an amount equal to the initial unit price, we will reduce the minimum quarterly distribution and the target distribution levels to zero. We will then make all future distributions from operating surplus, with 50.0% being paid to the unitholders, pro rata, and 50.0% to our general partner. The percentage interests shown for our general partner include its 2.0% general partner interest and assume that our general partner has not transferred the incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, we will proportionately adjust:

- the minimum quarterly distribution;

- the number of common units into which a subordinated unit is convertible;

- target distribution levels;

the unrecovered initial unit price; and

the number of general partner units comprising the general partner interest.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level, and each subordinated unit would be convertible into two common units. We will not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels for each quarter may be reduced by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus our general partner's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Distributions of Cash Upon Liquidation

General

If we dissolve in accordance with our partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and our general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Manner of Adjustments for Gain

The manner of the adjustment for gain is set forth in our partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to our partners in the following manner:

- *first*, to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

- *second*, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;

- *third*, 98.0% to the subordinated unitholders, pro rata, and 2.0% to our general partner, until the capital account for each subordinated unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

fourth, 98.0% to all unitholders, pro rata, and 2.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; *less* (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98.0% to the unitholders, pro rata, and 2.0% to our general partner, for each quarter of our existence;

fifth, 85.0% to all unitholders, pro rata, and 15.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; *less* (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85.0% to the unitholders, pro rata, and 15.0% to our general partner for each quarter of our existence;

sixth, 75.0% to all unitholders, pro rata, and 25.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; *less* (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75.0% to the unitholders, pro rata, and 25.0% to our general partner for each quarter of our existence;

thereafter, 50.0% to all unitholders, pro rata, and 50.0% to our general partner.

The percentages set forth above are based on the assumption that our general partner has not transferred its incentive distribution rights and that we do not issue additional classes of equity securities.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the fourth bullet point above will no longer be applicable.

Manner of Adjustments for Losses

If our liquidation occurs before the end of the subordination period, after making allocations of loss to the general partner and the unitholders in a manner intended to offset in reverse order the allocations of gains that have previously been allocated, we will generally allocate any loss to our general partner and unitholders in the following manner:

first, 98.0% to the holders of subordinated units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the subordinated unitholders have been reduced to zero;

second, 98.0% to the holders of common units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the common unitholders have been reduced to zero; and

thereafter, 100.0% to our general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

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Adjustments to Capital Accounts

Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we generally allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the partners' capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made. In contrast to the allocations of gain, and except as provided above, we generally will allocate any unrealized and unrecognized loss resulting from the adjustments to capital accounts upon the issuance of additional units to the unitholders and our general partner based on their respective percentage ownership of us. In this manner, prior to the end of the subordination period, we generally will allocate any such loss equally with respect to our common and subordinated units. If we make negative adjustments to the capital accounts as a result of such loss, future positive adjustments resulting from the issuance of additional units will be allocated in a manner designed to reverse the prior negative adjustments, and special allocations will be made upon liquidation in a manner that results, to the extent possible, in our unitholders' capital account balances equaling the amounts they would have been if no earlier adjustments for loss had been made.

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SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table presents as of the dates and for the periods indicated our selected historical and pro forma consolidated financial and operating data, as well as the selected historical combined financial and operating data of our Predecessor.

The selected historical combined financial data for the period from January 1, 2009 to July 31, 2009 is derived from the audited historical combined financial statements of our Predecessor included elsewhere in this prospectus. The selected historical combined balance sheet data as of July 31, 2009 is derived from the unaudited historical combined financial statements of our Predecessor that are not included in this prospectus. The selected historical consolidated balance sheet data presented as of December 31, 2009 of Southcross Energy LLC is derived from the audited historical consolidated financial statements of Southcross Energy LLC that are not included in this prospectus. The selected historical consolidated financial data presented as of December 31, 2010 and December 31, 2011 and for the period from June 2, 2009 (date of inception) to December 31, 2009 and for the years ended December 31, 2010 and December 31, 2011 have been derived from the audited historical consolidated financial statements of Southcross Energy LLC included elsewhere in this prospectus. The selected historical consolidated financial data presented as of March 31, 2012 and for the three months ended March 31, 2011 and March 31, 2012 are derived from our unaudited historical condensed financial statements included elsewhere in this prospectus. We acquired our initial assets from Crosstex effective as of August 1, 2009. During the period from our inception on June 2, 2009 to July 31, 2009, we had no operations although we incurred certain fees and expenses of approximately $3.0 million associated with our formation and the acquisition of our initial assets from Crosstex, which are reflected in the "Transaction costs" line item of our selected historical consolidated financial data for the period from June 2, 2009 (date of inception) to December 31, 2009.

The selected pro forma consolidated financial data for the three months ended March 31, 2012 and for the year ended December 31, 2011 have been derived from our unaudited pro forma consolidated financial statements included elsewhere in this prospectus. The selected pro forma consolidated statement of operations for the year ended December 31, 2011 includes the pro forma effects of the EAI acquisition and the pro forma effects of the recapitalization transactions described under "Summary Recapitalization Transactions and Partnership Structure" as if the EAI acquisition and the recapitalization transactions occurred as of January 1, 2011. The selected pro forma consolidated statement of operations for the three months ended March 31, 2012 presents the pro forma effects of the recapitalization transactions as if they occurred as of January 1, 2011.

For a detailed discussion of the following table, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations." The following table should also be read in conjunction with the historical audited and unaudited consolidated financial statements and related notes of Southcross Energy LLC and our Predecessor's audited combined financial statements and related notes included elsewhere in this prospectus. Among other things, those historical financial

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statements include more detailed information regarding the basis of presentation for the information below.

	Southcross Energy Predecessor	**Southcross Energy LLC**					**Pro Forma Southcross Energy Partners, L.P.**	
	Period from January 1, 2009 to July 31, 2009	**Period from June 2, 2009 to December 31, 2009**	**Year Ended December 31, 2010**	**Year Ended December 31, 2011(3)**	**Three Months Ended March 31, 2011**	**Three Months Ended March 31, 2012**	**Year Ended December 31, 2011**	**Three Months Ended March 31, 2012**
	(in thousands, except for volume and price amounts)							
Statement of Operations Data:								
Total Revenue	$ 330,870	$ 206,634	$ 498,747	$ 523,149	$ 120,999	$ 120,617	$ 548,152	$ 120,617
Expenses:								
Cost of natural gas and liquids sold	301,368	179,045	439,431	460,580	105,752	99,202	479,376	99,202
Operations and maintenance	10,648	7,847	21,106	24,707	4,834	7,197	28,701	7,197
Depreciation and amortization	7,268	4,235	10,987	12,345	2,795	3,665	13,200	3,665
General and administrative	9,788	3,225	7,341	8,926	1,970	2,433	9,312	2,443
Transaction costs		2,957	149	203			203	
Total expenses	329,072	197,309	479,014	506,761	115,351	112,497	530,792	112,497
Income from operations	1,798	9,325	19,733	16,388	5,648	8,120	17,360	8,120
Interest income		9	25	24	8	2	24	2
Loss on extinguishment of debt				(3,240)			(3,240)	
Interest expense		(4,554)	(10,038)	(5,372)	(1,634)	(1,801)	(7,307)	(1,212)
Income tax expense	(77)	(372)	(1)	(261)	(65)	(85)	(261)	(85)
Net income	$ 1,721	$ 4,408	$ 9,719	$ 7,539	$ 3,957	$ 6,236	$ 6,576	$ 6,825
Statement of Cash Flows Data:								
Net cash provided by (used in):								
Operating activities	$ 4,955	$ 10,164	$ 25,493	$ 20,007	$ 272	$ 4,638		
Investing activities	(791)	(238,339)	(5,231)	(144,602)	(14,882)	(38,912)		
Financing activities	(4,164)	233,899	(5,663)	105,684	(4,766)	46,847		
Balance Sheet Data (at period end):								
Cash and cash equivalents	$	$ 5,724	$ 20,323	$ 1,412	$ 947	$ 13,985		
Trade accounts receivable	50,707	39,956	35,059	41,234	32,942	35,670		
Property, plant, and equipment, net	111,645	235,065	229,309	369,861	244,658	411,825		
Total assets	167,503	287,808	289,643	420,385	282,954	470,810		
Total debt (current and long term)		119,949	115,000	208,280	110,234	237,408		
Other Financial Data:								
Adjusted EBITDA(1)	$ 9,236	$ 16,517	$ 30,869	$ 28,936	$ 8,443	$ 11,785	$ 30,763	$ 11,785
Gross operating margin(2)	29,502	27,589	59,316	62,569	15,247	21,415	68,776	21,415
Maintenance capital expenditures	565	3,025	3,402	5,317	502	348	5,423	348
Expansion capital expenditures	250	1,669	1,843	150,669	17,642	45,266	150,669	45,266
Operating data:								
Average throughput of gas (MMBtu/d)	592,243	492,350	471,265	506,975	452,941	583,198	532,746	583,198
Average volume of NGLs delivered (Mgal/d)	241.8	225.5	233.4	215.5	220.3	385.2	215.5	385.2
Average volume input to our processing plants (MMBtu/d)	100,596	96,135	95,336	97,028	85,806	122,517	97,028	122,517
Realized prices on natural gas volumes sold/Btu ($/MMBtu)	$ 3.95	$ 3.97	$ 4.42	$ 4.05	$ 4.14	$ 2.69	$ 4.07	$ 2.69
Realized prices on NGL volumes sold/gal ($/gal)	$ 0.69	$ 1.01	$ 1.10	$ 1.35	$ 1.19	$ 1.05	$ 1.35	$ 1.05

(1) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read " Non-GAAP Financial Measures," and for a discussion of how we use Adjusted EBITDA to evaluate our operating

performance, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations."

(2) For a definition of gross operating margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read " Non-GAAP Financial Measures," and for a discussion of how we use gross operating margin to evaluate our operating performance, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations."

(3) The Summary Historical Financial and Operating Data for the year ended December 31, 2011 includes four months of financial and operating results for the EAI acquisition.

Non-GAAP Financial Measures

We include in this prospectus the non-GAAP financial measures of Adjusted EBITDA and gross operating margin. We provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP.

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Adjusted EBITDA

We define Adjusted EBITDA as net income:

Plus:

- Interest expense;
- Income tax expense;
- Depreciation and amortization expense;
- Certain non-cash charges such as non-cash equity compensation;
- Unrealized losses on commodity derivative contracts; and
- Selected charges / transaction costs that are unusual or non-recurring.

Less:

- Interest income;
- Income tax benefit;
- Unrealized gains on commodity derivative contracts; and
- Selected gains that are unusual or non-recurring.

Adjusted EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors and lenders, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to support our indebtedness and make cash distributions to our unitholders and general partner;
- our 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 alternative investment opportunities.

The economic rationale behind management's use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors. The GAAP measure most directly comparable to Adjusted EBITDA is net income. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to net income. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Adjusted EBITDA has limitations as an analytical tool and should not be considered as an alternative to, or more meaningful than, performance measures calculated in accordance with GAAP. Some of these limitations are:

- certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure;

- Adjusted EBITDA does not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;

- Adjusted EBITDA does not reflect changes in, or cash requirements for, our working capital needs;

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although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and Adjusted EBITDA does not reflect any cash requirements for such replacements; and

our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management's decision-making process.

The following table presents a reconciliation of Adjusted EBITDA to net cash flows provided by operating activities and net income for each of the periods indicated:

	Southcross Energy Predecessor	Southcross Energy LLC					Pro Forma Southcross Energy Partners, L.P.	
	Period from January 1, 2009 to July 31, 2009	Period from June 2, 2009 to December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011	Three Months Ended March 31, 2011	Three Months Ended March 31, 2012	Year Ended December 31, 2011	Three Months Ended March 31, 2012
	(in thousands)							
Reconciliation of Adjusted EBITDA to Net Cash Flows Provided by Operating Activities and Net Income								
Net cash flows provided by operating activities	4,955	10,164	25,493	20,007	272	4,638		
Add (deduct):								
Depreciation and amortization expense	(7,268)	(4,235)	(10,987)	(12,345)	(2,795)	(3,665)		
Loss on extinguishment of debt				(3,240)				
Deferred financing fees amortization		(897)	(2,158)	(882)	(303)	(283)		
Gain on sales of plant, property and equipment			13	522	522			
Unrealized derivatives loss	(170)			(21)	(186)	(222)		
Realized gains on cash flow hedge	823							
Accounts receivable	1,293	39,956	(4,897)	2,806	(347)	(5,564)		
Accrued sales	(32,347)							
Prepaid expenses and other	1,464	833	(560)	497	(257)	(669)		
Other non-current assets		534	(158)	2,155	15	135		
Accounts payable	(920)	(38,933)	3,836	(2,759)	2,799	9,769		
Accrued cost of sales	32,542							
Interest payable		(197)	(1,582)	1,755	1,514	(24)		
Accrued expenses and other liabilities	2,174	(2,817)	719	(809)	(1,753)	2,121		
Commodity assets and liabilities	(825)			(147)				
Net Income	$ 1,721	$ 4,408	$ 9,719	$ 7,539	$ 3,957	$ 6,236	$ 6,576	$ 6,825
Add:								
Depreciation and amortization expense	7,268	4,235	10,987	12,345	2,795	3,665	13,200	3,665
Interest expense		4,554	10,038	5,372	1,634	1,801	7,307	1,212
Unrealized gain (loss) on commodity derivatives	170							
Loss on extinguishment of debt				3,240			3,240	
Transaction costs		2,957	149	203			203	
Income tax expense	77	372	1	261	65	85	261	85
Less:								
Interest income		9	25	24	8	2	24	2
Adjusted EBITDA	$ 9,236	$ 16,517	$ 30,869	$ 28,936	$ 8,443	$ 11,785	$ 30,763	$ 11,785

Gross Operating Margin

We define gross operating margin as the sum of all revenues less the cost of natural gas and NGLs sold. Gross operating margin is used as a supplemental performance measure by our management to compare the net contribution of all of our contracts, particularly comparing the net contribution of fixed-spread and percent-of-proceeds contracts which record both revenue and costs compared to our fee based business which records revenue only. Gross operating margin reflects the net contribution to income of our contracts before the costs associated with operating and maintaining the system and general and administrative expenses. As an indicator of our operating performance, gross operating

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margin should not be considered an alternative to, or more meaningful than net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross operating margin in the same manner. The following table presents a reconciliation of gross operating margin to net income for each of the periods indicated:

	Southcross Energy Predecessor	Southcross Energy LLC					Pro Forma Southcross Energy Partners, L.P.	
	Period from January 1, 2009 to July 31, 2009	Period from June 2, 2009 to December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011	Three Months Ended March 31, 2011 (unaudited)	Three Months Ended March 31, 2012 (unaudited)	Year Ended December 31, 2011 (unaudited)	Three Months Ended March 31, 2012 (unaudited)
	(in thousands)							
Reconciliation of Gross Operating Margin to Net Income								
Net Income	$ 1,721	$ 4,408	$ 9,719	$ 7,539	$ 3,957	$ 6,236	$ 6,576	$ 6,825
Add:								
Income tax expense	77	372	1	261	65	85	261	85
Interest expense		4,554	10,038	5,372	1,634	1,801	7,307	1,212
Loss on extinguishment of debt				3,240			3,240	
Transaction costs		2,957	149	203			203	
General and administrative expense	9,788	3,225	7,341	8,926	1,970	2,433	9,312	2,433
Depreciation and amortization expense	7,268	4,235	10,987	12,345	2,795	3,665	13,200	3,665
Operations and maintenance expense	10,648	7,847	21,106	24,707	4,834	7,197	28,701	7,197
Less:								
Interest income		9	25	24	8	2	24	2
Gross operating margin	$ 29,502	$ 27,589	$ 59,316	$ 62,569	$ 15,247	$ 21,415	$ 68,776	$ 21,415

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion of the financial condition and results of operations of Southcross Energy Partners, L.P. and its subsidiaries in conjunction with the historical consolidated financial statements and related notes of Southcross Energy LLC and the historical combined financial statements and related notes of our Predecessor included elsewhere in this prospectus. Among other things, those financial statements and the related notes include more detailed information regarding the basis of presentation for the following information.

Overview

We are a growth-oriented limited partnership that was formed by members of our management team and Charlesbank to own, operate, develop and acquire midstream energy assets. We provide natural gas gathering, processing, treating, compression and transportation services and NGL fractionation services to our producer customers, primarily under fixed-fee and fixed-spread contracts, and we also source, purchase, transport and sell natural gas and NGLs to our power generation, industrial and utility customers. Our assets are located in South Texas, Mississippi and Alabama. Our South Texas assets, which consist of approximately 1,445 miles of pipeline, two processing plants and one fractionation plant and accounted for approximately 77% of our revenue for the year ended December 31, 2011, operate in or within close proximity to the Eagle Ford shale region, which has experienced a strong increase in investment and drilling activity by exploration and production companies in recent years. Based on industry data compiled by Smith Bits, a subsidiary of Smith International, Inc., approximately 14.2% of all drilling rigs in the United States were operating in the Eagle Ford shale region as of May 25, 2012. We expect this heightened Eagle Ford shale activity, as well as activity in the frequently overlying Olmos tight sand formation, will result in higher throughput on our South Texas systems and opportunities to expand our asset base over the next several years. Our Mississippi and Alabama assets, which consist of approximately 626 and 519 miles of pipeline, respectively, are strategically positioned to provide transportation of natural gas to our power generation, industrial and utility customers as well as to unaffiliated interstate pipelines. We expect to grow our business and distributable cash flow by expanding the capacity and efficiency of our assets and by making selective acquisitions, such as our acquisition in September 2011 of Enterprise Alabama Intrastate, LLC, or EAI, an intrastate pipeline and gathering system in Alabama, from a subsidiary of Enterprise Products Partners L.P.

Our Operations

Our integrated operations provide a full range of complementary services 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 the NGLs from the natural gas, fractionating the resulting NGLs into the various components and selling or delivering pipeline quality natural gas and NGLs to various industrial and energy markets as well as interstate pipeline systems. Through our network of pipelines, we provide the means of connecting our suppliers of natural gas to our customers, which include local distribution companies, or LDCs, and industrial, commercial and power generation customers.

Our results are determined primarily by the volumes of natural gas we gather and process, the efficiency of our processing plants and fractionation plant, the commercial terms of our contractual arrangements and natural gas and NGL prices. We manage our business to attempt 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 ten years and the pricing under our contracts varies depending upon several factors, including our competitive position, our acceptance of any risk associated with a longer-term contract and our desire to recoup over the term of the contract any capital expenditures that we are required to incur in order to connect a counterparty to our pipeline system. We gather, process, transport and sell natural gas and fractionate and sell NGLs primarily pursuant to 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 transport or 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 from producers or suppliers at receipt points on our systems at an index price less a fixed amount and sell an identical volume of natural gas at delivery points on our systems at a price that is greater than the purchase price. By entering into such back-to-back purchases and sales of natural gas, we are able to lock in a fixed spread on these transactions.

Percent-of-Proceeds ("POP"). In exchange for our processing services, we remit to a producer customer a percentage of the proceeds from our sales of residue natural gas and/or NGLs that result from our natural gas processing, or in some cases, a percentage of the physical natural gas and/or NGLs at the tailgate of our processing plant, and we retain the balance of the proceeds or physical commodity for our own account. These arrangements are typically combined with fixed fees for processing volumes and, therefore, represent only a portion of a processing contract's value. We are subject to direct commodity price risk from these arrangements because the revenues we receive from these contracts directly correlate with the fluctuating price of natural gas and NGLs. We are also subject to operating risk to the extent we may guarantee a certain level of recovery of NGLs. On our Gulf Coast System, we arrange for other parties to process natural gas on our behalf. The most significant of these arrangements is with Formosa Hydrocarbons Company, Inc., or Formosa, which is an affiliate of Formosa Plastics Corporation, U.S.A. Our processing contract with Formosa entitles us to the greater of (1) a fixed percentage of the value of the NGLs resulting from processing plus 100% of the value of the residue natural gas (an "upgrade" percent-of-proceeds payment) and (2) the value of the unprocessed volume of natural gas priced relative to the same index prices pursuant to which we acquired the natural gas (a "floor" percent-of-proceeds payment). This contract structure insulates us from the exposure to scenarios in which the price we pay for the unprocessed natural gas exceeds the price of the NGL stream resulting from Formosa's processing activities and the residue natural gas, while preserving for us the opportunity to generate attractive processing economics when the relative commodity prices favor processing. Our current arrangement with Formosa will expire in January 2013.

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 at a fixed spread. Gross operating margin earned under fixed-fee and fixed-spread arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. 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. These arrangements provide stable cash flows but minimal, if any, upside in higher commodity price environments. Our fixed-spread contracts expose us to commodity price risk, as we are unable to balance exactly the purchase and sale of natural gas on an aggregate basis across all of our systems. We purchase natural gas from producers and other third parties and sell natural gas to our customers based on demand forecasts for the subsequent month. Disruptions in producer volumes or in market demand may result in imbalances on our systems, which will increase our exposure to commodity price risks and could result in increased volatility in our revenue, gross operating margin and cash flows. Under the typical POP contract, our gross operating margin is directly impacted by the commodity prices we realize on our share of natural gas and NGLs received as

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compensation for processing natural gas. However, our POP arrangements also often contain a fixed fee for other services that mitigates the degree of commodity-price volatility we experience under these arrangements. We may further seek to mitigate our exposure to commodity price risk through our hedging program. Please read "Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk."

Contract Mix

Set forth below is a table summarizing our average contract mix for the years ended December 31, 2010 and 2011.

	Year Ended December 31, 2010		Year Ended December 31, 2011		Three Months Ended March 31, 2011		Three Months Ended March 31, 2012	
	Gross operating margin (in thousands)	**Percent of total gross operating margin**	**Gross operating margin (in thousands)**	**Percent of total gross operating margin**	**Gross operating margin (in thousands)**	**Percent of total gross operating margin**	**Gross operating margin (in thousands)**	**Percent of total gross operating margin**
Fixed-fee	$27,979	47.2%	$32,340	51.7%	$7,244	47.5%	$11,018	51.4%
Fixed-spread	12,223	20.6	12,204	19.6	2,955	19.4	2,198	10.3
POP floor(1)	2,860	4.8	2,340	3.7	679	4.5	399	1.9
Sub-total	$43,062	72.6%	$46,884	75.0%	$10,878	71.4%	$13,615	63.6%
POP	5,496	9.3	4,339	6.9	1,409	9.2	4,253	19.9
POP upgrade(2)	10,758	18.1	11,346	18.1	2,960	19.4	3,547	16.5
Total	$59,316	100%	$62,569	100%	$15,247	100%	$21,415	100%

(1) Represents that portion of gross operating margin under the processing arrangement with Formosa that is derived on a fixed-spread basis.

(2) Represents that portion of gross operating margin under the processing arrangement with Formosa that is derived from a fixed percentage of the value of the NGLs delivered and the residue gas. This margin will vary with the relative prices of NGLs and natural gas and is not realized when the price of NGLs is low relative to the price of natural gas.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on at least a monthly basis for consistency and trend analysis. These metrics include (i) throughput volume, (ii) gross operating margin, (iii) operations and maintenance expenses, (iv) Adjusted EBITDA, and (v) distributable cash flow. We manage our business and analyze our results of operations through one business segment. We determine and analyze throughput volumes by operating unit but report overall throughput volumes after elimination of intercompany deliveries.

Throughput Volume

The throughput volume of natural gas and NGLs on our systems depends on the level of production from natural gas wells connected to our systems as well as from wells connected with other pipeline systems that are interconnected with ours. Production levels are determined by the amount of drilling and completion activity because producing wells' rates decline over time and production must be replaced by new drilling or other activity. Producers' willingness to engage in new drilling is influenced by a number of factors, the most important of which are the prevailing and projected prices of natural gas and NGLs, the availability and cost of capital and environmental and governmental

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regulations. Historically, the level of drilling declines or rises along with commodity prices. Over time, production levels generally decline or rise as drilling activity decreases or increases.

We must continually obtain new supplies of natural gas to maintain or increase the throughput volume on our systems. Our ability to maintain or increase existing throughput volumes of natural gas and obtain new supplies is impacted by (i) the level of work-overs or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to or near our pipeline systems, (ii) our ability to compete for volumes from successful new wells in the areas in which we operate, (iii) our ability to obtain natural gas that has been released from other commitments and (iv) the volume of natural gas that we purchase from connected systems. Our ability to maintain or increase the throughput volumes of NGLs on our systems depends on the amount of liquids-rich natural gas available for inlet into our plants. We actively monitor producer activity in the areas served by our gathering and transportation services and processing plants to pursue new supply and delivery opportunities.

The table below shows our average natural gas throughput volumes and the amount of NGLs delivered for the periods indicated.

	Year Ended December 31, 2009(1)	Year Ended December 31, 2010	% Change	Year Ended December 31, 2011	% Change	Three Months Ended March 31, 2011	Three Months Ended March 31, 2012	% Change
Average throughput volume								
Natural Gas (MMBtu/d)								
South Texas	415,619	343,317	(17.4)%	363,545	5.9%	340,186	376,610	10.7%
Mississippi / Alabama	134,751	127,948	(5.0)%	143,430	12.1%	112,755	206,588	83.2%
Total Natural Gas	550,370	471,265	(14.4)%	506,975	7.6%	452,941	583,198	28.8%
NGLs (Mgal/d)	235.0	233.4	(0.7)%	215.5	(7.7)%	220.3	385.2	74.8%
Average inlet volume of natural gas to our processing plants (MMBtu/d)	98,726	95,336	(3.4)%	97,028	1.8%	85,806	122,517	42.8%
Average inlet volume of natural gas to Formosa (MMBtu/d)	79,027	56,784	(28.1)%	55,842	(1.7)%	48,228	89,506	85.6%

(1) Represents the combined throughput volumes of Southcross Energy Predecessor prior to August 1, 2009 and our throughput volumes on and after August 1, 2009.

South Texas. Our throughput volumes in South Texas are directly affected by the level of drilling and well completions by producers, which in turn is affected largely by natural gas and NGL prices, as well as our level of activity in connecting new supply sources.

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We believe that the number of drilling rigs operating in our defined pipeline areas over time is a useful benchmark in analyzing changes in throughput volume on our South Texas system.

Quarterly Rig Count in Core Historic Pipeline Area(1)

(1) Our defined core historic pipeline area consists of Aransas, Bee, DeWitt, Duval, Ft. Bend, Jackson, Jim Wells, Karnes, Nueces, Refugio, San Patricio, Victoria and Wharton counties.

Source: Smith Bits, a subsidiary of Smith International, Inc.

The number of drilling rigs operating in our core historic pipeline area decreased from 24 to 11, or 54.2%, from the end of 2008 through the third quarter of 2009 due to a decline in natural gas and oil prices, limitations on producers' access to capital and a reallocation of capital by producers to areas known to contain unconventional resources, such as the Haynesville and Barnett Shale regions. Since the fourth quarter of 2009, however, drilling in our core historic pipeline area has been favorably impacted by the dramatically increased drilling activity in the Eagle Ford shale area as the potential for unconventional drilling and liquid-rich natural gas recovery in that area increasingly has become a focal point for producers. Rising oil and NGL prices and drilling successes have served to further producers' interest in this prolific area over the last two years.

We believe that the geographical, regulatory and compositional features of the Eagle Ford shale make it an economically favorable region for oil and natural gas producers and, therefore, for providers of midstream services in the region. The Eagle Ford shale is located in close proximity to significant pre-existing production, allowing for efficient logistics and supply chains, has a climate that enables year-round operations and is governed by a regulatory environment that is relatively supportive of the oil and natural gas industry. Furthermore, we believe that the oil- and liquids-rich areas of the Eagle Ford shale will remain economically attractive regardless of the price of natural gas and even if oil prices fall below current levels. Accordingly, we believe drilling activity in this area will continue to support sustained growth in demand for our services.

Reflecting this increased activity, the number of drilling rigs in our core pipeline areas increased by approximately 6.7 times from the second quarter of 2009 to the fourth quarter of 2011, and the number of active rigs in our Eagle Ford Southcross pipeline catchment area (which consists of Bee, DeWitt, Karnes, LaSalle, Live Oak, McMullen and Webb Counties) increased by approximately 5.5 times over that same period.

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While oil and liquids-rich drilling in South Texas has greatly increased over the past two years, we did not experience a corresponding impact on our throughput volumes in 2010 and the first half of 2011 for two reasons. First, a portion of the new drilling activity has been focused on oil-producing areas, whereas our historical assets prior to our recent expansion activity were more focused in the dry-gas producing areas in South Texas. Second, the lag time between drilling and initiation of production has had the effect of delaying some of the impact of drilling activity on throughput volumes.

During 2011, however, we began to experience the benefits of our growing position in the Eagle Ford shale area in South Texas. In particular, we benefited from the addition of throughput volumes on our McMullen County pipeline extension in the fourth quarter of 2011, which enabled us to increase our throughput volumes in South Texas by 5.9% in 2011 compared to 2010. We anticipate that our expanding position in the liquids-rich portions of the Eagle Ford shale area, combined with continued high levels of drilling and increasing levels of production in this region, will be the principal factors driving our future throughput volumes in South Texas.

Mississippi / Alabama. Power generation, industrial and utility customer requirements and natural gas prices have a major influence on throughput volumes on our Mississippi system. Volumes on this system can be volatile over time due to occasional, high-volume sales of natural gas we purchase and sell to off-system markets. These sales are sporadic because they take advantage of basis differentials between different regions of the country, which are highly variable. The throughput volumes on our Mississippi system have decreased since early 2009 due to the lack of opportunity for such sales. Historically, Alabama production on our system has been from relatively shallow wells in the Black Warrior Basin with some coal bed methane (CBM) production. Beginning with the EAI acquisition, our connected wells began to consist primarily of CBM production. Production attributable to the CBM wells in this basin decreased by an average of 9.8% per year from 2008 to 2011. We currently use this benchmark to evaluate our throughput in this area.

Our Mississippi and Alabama throughput volumes were down 5.0% in 2010 compared to 2009, even though the 2010 volumes benefited from a full year of throughput on our Delta Pipeline that was completed in the third quarter of 2009. Without the Delta Pipeline, volumes declined by 18.6% in 2010 compared to 2009, primarily as a result of lower volumes sold and moved off-system and of reduced drilling by producers, which we believe was caused by lower natural gas prices. In 2011, throughput on all our systems increased by 12.1% from 2010 levels, primarily as a result of additional throughput attributable to the EAI acquisition.

Gross Operating Margin

Gross operating margin associated with our different contractual arrangements is one of the primary metrics we use to measure and evaluate our performance. See "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures." We define gross operating margin as the sum of all revenues less the cost of natural gas and NGLs sold. For our fixed-fee contracts, we record the fee as revenue and there is no offsetting cost of natural gas and NGLs sold. For our fixed-spread and POP arrangements, we will record as revenue all of our proceeds from the sale of the natural gas or NGLs and record as an expense the associated cost of natural gas and NGLs sold.

Operations and Maintenance Expense

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

Adjusted EBITDA and Distributable Cash Flow

We define Adjusted EBITDA as net income, plus interest expense, income tax expense, depreciation and amortization expense, certain non-cash charges such as non-cash equity compensation, unrealized losses on commodity derivative contracts and selected charges and transaction costs that are unusual or non-recurring, less interest income, income tax benefit, unrealized gains on commodity derivative contracts and selected gains that are unusual or non-recurring. See "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures." Although we have not quantified distributable cash flow on a historical basis, after the closing of this offering we intend to use distributable cash flow, which we define as Adjusted EBITDA plus interest income, less cash paid for interest expense, taxes and maintenance capital expenditures, to analyze our performance. Distributable cash flow will not reflect changes in working capital balances. Adjusted EBITDA and distributable cash flow are used as supplemental measures by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

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

Note Regarding Non-GAAP Financial Measures

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

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented and those of our Predecessor may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- Effective September 1, 2011, we completed the EAI acquisition, and, therefore, our financial and operating data for the year ended December 31, 2011 includes four months of results for the EAI acquisition.

- Because we acquired our initial assets effective as of August 1, 2009, the financial and operational data for 2009 that is discussed below is generally bifurcated between the period that our Predecessor owned those assets and the period from our acquisition of those assets through the end of the year. Moreover, there is some overlap between these two periods resulting from the fact that we were formed on June 2, 2009, which was prior to the effective date of the acquisition of the Crosstex assets on August 1, 2009. As a result, the 2009 period that our Predecessor owned and operated the assets is the seven months ended July 31, 2009, while the successor 2009 period begins with our inception on June 2, 2009 and ends on December 31, 2009. Although we incurred costs of approximately $3.0 million associated with our formation and our initial acquisition of assets, we had no material operations for financial reporting purposes until August 1, 2009.

- The historical combined financial statements and related notes of our Predecessor:

  - are presented on a combined rather than a consolidated basis. These combined financial statements represent the financial position, results of operations, changes in owner's equity and cash flows of our Predecessor, and have been carved out of the accounting records maintained by Crosstex and its subsidiaries;

  - include an estimate for corporate general and administration ("G&A") expenses as Crosstex did not allocate any of the central finance and administration costs of Crosstex to its operating entities. We have based this estimate of G&A expense for our Predecessor on an allocation of Crosstex's total G&A expenses based upon our Predecessor's revenue for each year as a percentage of Crosstex's total revenue for each year;

  - reflect the operation of our assets with different business strategies and as part of a larger business rather than the stand-alone fashion in which we operate them. Please read "Business Business Strategies"; and

  - do not include any results from the Delta Pipeline, which we acquired in August 2009 but which had no operations prior to our acquisition.

- In connection with our formation and our initial acquisition of assets, we incurred transaction expenses of $2,957,000 in 2009 and $149,000 in 2010.

- In connection with our initial acquisition of assets:

  - we executed a transition services agreement with Crosstex under which Crosstex agreed to provide gas control, operating, information technology, regulatory, contract administration, and selected accounting services over a period of four months ending December 1, 2009, during which time we hired and trained personnel, acquired equipment and facilities, installed stand-alone computer systems, and became functionally independent. We paid Crosstex $1,000,000 for these services and accounted for this payment as a G&A expense;

we entered into an advisory services agreement with certain affiliates of Charlesbank that resulted in higher G&A expenses. Please read "Certain Relationships and Related Party Transactions Agreements with Affiliates"; and

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we recorded our assets at fair value, which was greater than our Predecessor's book value of those assets, and their useful lives were also changed, which had the net effect of decreasing the depreciation expense associated with our assets after the acquisition date.

No interest expense or short-term or long-term debt was allocated to our Predecessor by our Predecessor's publicly traded parent entity, which utilized a central treasury function that controlled all cash disbursements and provided all sources of funding on a company-wide basis. We incurred substantial indebtedness to finance the acquisition of our initial assets from Crosstex, which has led to the incurrence of interest expense reported.

Although we did not acquire any hedging positions from Crosstex, the historical combined financial statements of our Predecessor reflect actual positions that Crosstex established to manage the commodity risk of the specific operations of the assets that we acquired. Crosstex commonly entered into various derivative financial transactions which it did not designate as hedges. These transactions include "swing swaps," "third party on-system financial swaps," "storage swaps," and "basis swaps." Swing swaps are generally short-term in nature (one month) and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that Crosstex entered into on behalf of its customers who are connected to its systems, wherein Crosstex fixed a supply or market price for a period of time for its customers, and simultaneously entered into a derivative transaction. Storage swap transactions protect against changes in the value of gas that Crosstex stored to serve various operational requirements. Basis swaps are used to hedge basis location price risk due to buying gas into one of our systems on one index and selling gas off that same system on a different index. Crosstex accounted for these derivative financial transactions using mark-to-market accounting and these amounts are included in the historical combined financial statements of our Predecessor. In contrast, since the time that we have owned our assets we have entered into only swing swaps to protect against changes in the volume of daily versus first-of-month index priced natural gas supplies or markets.

General Trends and Outlook

We expect our business to continue to be affected by the 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.

Supply and Demand for Natural Gas and Oil Generally

Beginning in the second half of 2008, the United States and other industrialized countries experienced a significant economic downturn that led to a decline in worldwide energy demand. During this same period, North American oil and natural gas supply was increasing as a result of the rise in domestic unconventional production. The combination of lower energy demand due to the economic downturn and higher North American oil and natural gas supply resulted in significant decreases in oil, NGL and natural gas prices. While oil and NGL prices began to increase steadily in the second quarter of 2009, natural gas prices remained lower and volatile throughout 2009 and 2010 in comparison to much of 2007 and 2008. New supplies of natural gas, largely from unconventional sources, continued to keep prices at relatively low levels in 2011. The balance of supply and demand for natural gas is difficult to predict. As a result, we expect natural gas prices to remain relatively low in the near term.

Natural gas continues to be a critical component of energy consumption in the United States. According to the U.S. Energy Information Administration, or EIA, domestic marketed production of natural gas grew from approximately 21.6 Tcf in 2009 to approximately 22.4 Tcf in 2010, or a 3.5%

increase. This trend of increasing production continued in 2011, with marketed production of natural gas in that period of approximately 24.2 Tcf, representing a 7.9% increase over the marketed production of natural gas during 2010. The industrial and electricity generation sectors currently account for the largest usage of natural gas in the U.S., representing approximately 59% of the total natural gas consumed during 2011. In particular, based on a report by the EIA, industrial natural gas demand is expected to grow from 7.1 Tcf in 2011 to 8.5 Tcf in 2020 as a result of an expected recovery in industrial production.

Commodity Prices and Producer Activity

Our gross operating margins and total distributable cash flow are influenced by natural gas and NGL prices and by drilling activity. Natural gas prices affect the long-term growth and sustainability of our business because they influence natural gas exploration and production activity.

Factors Influencing Commodity Prices. Natural gas and NGL prices generally are influenced by a variety of factors that affect supply and demand. These factors include regional drilling activity, available pipeline capacity, the severity of winter and summer weather (and other factors that influence consumption), natural gas storage levels, competing supplies, and NGL transportation and fractionation capacity. Many of these factors are in turn dependent on overall economic activity. Economic recovery in the U.S. has been slow, and the strength and sustainability of the recovery remain uncertain. A renewed slowdown in economic activity could result in declines in natural gas and NGL prices and reduced drilling activity.

Effect of Prices on Drilling and Production. Commodity price fluctuations are among the factors that natural gas producers consider as they schedule drilling projects. Producers typically increase drilling activity when natural gas prices are sufficient to make drilling and production economic and, depending on the severity and duration of an unfavorable pricing environment, they may suspend activity to the degree such activity has become uneconomic. These changes in drilling activity are reflected in production volumes (and in turn, in our throughput volumes) only gradually because of the time required to drill, complete and connect new wells and the gradual decline of continuing production from already-completed wells. Delays between drilling and production can range from a few days in areas with minimal completion and connection processes to as long as 12 months due to shortages in completion equipment or the need to await pipeline connections.

The level at which drilling and production become economically profitable depends on a variety of factors in addition to natural gas prices. For producers of liquids-rich natural gas who share in the benefits of improved processing economics under their sales contracts, the disincentive of low natural gas prices could be offset if NGL prices are consistently high relative to natural gas prices. Strong crude oil prices could also support increased production of casing head natural gas associated with oil production.

We believe generally that strong NGL pricing environments support growth in liquids-rich natural gas drilling; however, the effects of prices are subject to other factors, some of which could diminish a producer's ability and incentives to drill. These factors include the availability of capital and the producer's drilling, completion and other operating costs, which are influenced by the characteristics of the hydrocarbon reservoir, among other things. Some producers can rely on commodity price hedging to support drilling activity when prices are less favorable. Also, producers may drill when they otherwise would not to the extent that drilling activity is necessary to maintain their leasehold interests or under the terms of their capital commitments.

Growth in Production from U.S. Shale Plays. According to the EIA, the unproven amount of natural gas recoverable from U.S. shale resources is 750 Tcf, which is approximately 31 times the amount of total marketed production in the United States in 2011. According to the EIA, U.S.

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production of natural gas from shale has increased twelvefold since 2000 and in 2010 accounted for 23% of U.S. natural gas production. The EIA also projects that shale natural gas will increase to 47% of U.S. natural gas production in 2035.

In recent years, well-capitalized producers have leased large acreage positions in the Eagle Ford shale play and other unconventional resources plays, using leases that require producers to drill wells to retain the acreage. To help fund their drilling program in many of these areas, including in the Eagle Ford shale play, a number of producers have also entered into joint venture arrangements with large international operators and private equity sponsors. Typically, the joint venture partner will agree to fund a significant portion of the near-term drilling capital budget in exchange for an equity interest in the joint venture. These producers and their joint venture partners have committed significant capital to the development of the Eagle Ford shale plays and other unconventional resource plays, which we believe will result in sustained drilling activity.

Activity in the Eagle Ford shale area has increased significantly since production began in 2008. According to the TRRC, the number of permits issued to drill wells targeting the Eagle Ford shale area has increased as follows:

Eagle Ford Shale Drilling Permits Issued

Year	Drilling Permits Issued
2008	26
2009	94
2010	1,010
2011	2,826

As of January 1, 2009, the EIA estimated that the undeveloped technically recoverable reserves of the Eagle Ford shale formation had reached 21 Tcf of natural gas. According to the TRRC, natural gas production from the Eagle Ford shale formation increased from 52 MMcf/d in 2009 to 665 MMcf/d in 2011.

Results of Operations Combined Overview

The following table and discussion presents certain of our historical consolidated financial data and the historical combined financial data of our Predecessor for the periods indicated.

We refer to the results of our Predecessor's operations for the period from January 1, 2009 to July 31, 2009 as the 2009 Predecessor Period and to our operating results for the period from June 2, 2009 to December 31, 2009 as the 2009 Successor Period.

We acquired our initial assets effective as of August 1, 2009. During the period from our inception, on June 2, 2009, to August 1, 2009, we had no operations, but we incurred certain fees and expenses totaling $2,957,000 associated with our formation and our initial acquisition of assets.

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The financial data for the 2009 Predecessor Period represents a period of time prior to our acquisition of our initial assets. During that period, our Predecessor owned and operated these assets. As such, the results of operations for that period do not necessarily represent the results of operations that would have been achieved during the period had we owned and operated our assets.

	Southcross Energy Predecessor	Southcross Energy LLC				
	Period from January 1, 2009 to July 31, 2009	Period from June 2, 2009 to December 31,	Year Ended December 31,		Three Months Ended March 31,	
	2009	2009(3)	2010	2011(4)	2011	2012
	(in thousands, except for volume and price amounts)					
Statement of Operations Data:						
Total Revenue	$ 330,870	$ 206,634	$ 498,747	$ 523,149	$ 120,999	$ 120,617
Expenses:						
Cost of natural gas and liquids sold	301,368	179,045	439,431	460,580	105,752	99,202
Operations and maintenance	10,648	7,847	21,106	24,707	4,834	7,197
Depreciation and amortization	7,268	4,235	10,987	12,345	2,795	3,665
General and administrative	9,788	3,225	7,341	8,926	1,970	2,433
Transaction costs		2,957	149	203		
Total expenses	329,072	197,309	479,014	506,761	115,351	112,497
Income from operations	1,798	9,325	19,733	16,388	5,648	8,120
Interest income		9	25	24	8	2
Loss on extinguishment of debt				(3,240)		
Interest expense		(4,554)	(10,038)	(5,372)	(1,634)	(1,801)
Income tax expense	(77)	(372)	(1)	(261)	(65)	(85)
Net income	$ 1,721	$ 4,408	$ 9,719	$ 7,539	$ 3,957	$ 6,236
Statement of Cash Flows Data:						
Net cash provided by (used in):						
Operating activities	$ 4,955	$ 10,164	$ 25,493	$ 20,007	$ 272	$ 4,638
Investing activities	(791)	(238,339)	(5,231)	(144,602)	(14,882)	(38,912)
Financing activities	(4,164)	233,899	(5,663)	105,684	(4,766)	46,847
Balance Sheet Data (at period end):						
Cash and cash equivalents	$	$ 5,724	$ 20,323	$ 1,412	$ 947	$ 13,985
Trade accounts receivable	50,707	39,956	35,059	41,234	32,942	35,670
Property, plant, and equipment, net	111,645	235,065	229,309	369,861	244,658	411,825
Total assets	167,503	287,808	289,643	420,385	282,954	470,810
Total debt (current and long term)		119,949	115,000	208,280	110,234	237,408
Other Financial Data:						
Adjusted EBITDA(1)	$ 9,236	$ 16,517	$ 30,869	$ 28,936	$ 8,443	$ 11,785
Gross operating margin(2)	29,502	27,589	59,316	62,569	15,247	21,415
Maintenance capital expenditures	565	3,025	3,402	5,317	502	348
Expansion capital expenditures	250	1,669	1,843	150,669	17,642	45,266
Operating data:						
Average throughput volumes of natural gas (MMBtu/d)	592,243	492,350	471,265	506,975	452,941	583,198
Average volume of NGLs delivered (Mgal/d)	241.8	225.5	233.4	215.5	220.3	385.2
Average volume input to our processing plants (MMBtu/d)	100,596	96,135	95,336	97,028	85,806	122,517
Realized prices on natural gas volumes sold/Btu ($/MMBtu)	$ 3.95	$ 3.97	$ 4.42	$ 4.05	$ 4.14	$ 2.69
	$ 0.69	$ 1.01	$ 1.10	$ 1.35	$ 1.19	$ 1.05

Realized prices on NGL volumes sold/gal ($/gal)	

(1) For a definition of Adjusted EBITDA and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Selected Historical and Pro Forma Financial

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and Operating Data Non-GAAP Financial Measures," and for a discussion of how we use Adjusted EBITDA to evaluate our performance, please read " How We Evaluate Our Operations."

(2)
For a definition of gross operating margin and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Selected Historical and Pro Forma Financial and Operating Data Non-GAAP Financial Measures," and for a discussion of how we use gross operating margin to evaluate our performance, please read " How We Evaluate Our Operations."

(3)
Operating data is for the period from August 1, 2009 to December 31, 2009.

(4)
The Summary Historical Financial and Operating Data for the year ended December 31, 2011 includes four months of financial and operating results for the EAI acquisition.

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

Volume and overview. Our average throughput volume of natural gas per day increased by 28.8% to 583,198 MMBtu/d during the three months ended March 31, 2012, compared to 452,941 MMBtu/d during the three months ended March 31, 2011. Our South Texas throughput volumes for the three months ended March 31, 2012 increased by 10.7%, compared to the same period in 2011. This increase in our South Texas throughput volumes reflects the impact of new contracts we executed to support the completion of our McMullen pipeline extension, which was placed into service during the second half of 2011. Our Mississippi and Alabama throughput volumes increased 83.2% for the three months ended March 31, 2012, compared to the three months ended March 31, 2011. This increase was due to the inclusion of three months of throughput on our Alabama pipeline and gathering system that we acquired effective September 1, 2011. Without this additional volume, our average daily throughput volumes would have declined by 19.6% for our Mississippi and Alabama assets for the three months ended March 31, 2012, compared to the three months ended March 31, 2011. This decline was due primarily to our customers' demand variations and the loss of one industrial customer for a significant portion of the three months ended March 31, 2012. The average volume of NGLs produced for the three months ended March 31, 2012 was 385.2 Mgal/d, an increase of 74.8%, compared to 220.3 Mgal/d for the three months ended March 31, 2011. This increase is due to the impact of higher gas volumes being available to be processed at our Gregory and Conroe plants and higher volumes being processed at Formosa's processing facility pursuant to the terms of our agreement with Formosa.

Our gross operating margin for the three months ended March 31, 2012 increased to $21.4 million, compared to $15.2 million for the three months ended March 31, 2011. This increase of 40.5% was primarily due to the higher natural gas throughput and NGL volumes on our systems as well as a greater price spread between NGL and natural gas prices. This increase was primarily reflective of higher fixed fee margins as a result of the higher gas volumes and higher margins for our NGL business due to the increased price spread. We generated $6.2 million of net income for the three months ended March 31, 2012, compared to $4.0 million of net income for the three months ended March 31, 2011. This increase was primarily due to higher gross operating margin, partially offset by higher depreciation and amortization expense, increased operating and maintenance expense, higher general and administrative expense and increased interest expense. Adjusted EBITDA increased by 39.6% to $11.8 million for the three months ended March 31, 2012, compared to $8.4 million for the three months ended March 31, 2011, due primarily to higher gross operating margin, partially offset by increases in operating and maintenance and general and administrative expenses.

Revenue. Our total revenue for the three months ended March 31, 2012 was $120.6 million, compared to $121.0 million for the three months ended March 31, 2011. Our results for the three months ended March 31, 2012 include three months of activity related to our Alabama pipeline and gathering system that we acquired effective September 1, 2011, which contributed $7.3 million in revenue. Excluding the impact of the EAI acquisition, revenues declined 6.4% for the three months ended March 31, 2012, compared to the three months ended March 31, 2011. This decline in revenue is primarily due to the impact of lower natural gas prices on our gas sales contracts. We benefited from

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higher natural gas volumes under our fixed fee contracts in the 2012 period as, excluding the impact of the EAI acquisition, revenue from our transportation, gathering and processing fees increased by 41.6%. We also experienced a 56.1% increase in NGL sales reflecting the benefit of new pipelines delivering higher volumes to our processing plants, partially offset by lower NGL prices. We realized average natural gas and NGL prices of $2.69/MMBtu and $1.05/gal, respectively, for the three months ended March 31, 2012, compared to $4.14/MMBtu and $1.19/gal, respectively, for the three months ended March 31, 2011.

Cost of natural gas and liquids sold. Our cost of natural gas and liquids sold for the three months ended March 31, 2012 was $99.2 million, compared to $105.8 million for the three months ended March 31, 2011. This decline is due to the effect of lower natural gas prices more than offsetting the higher throughput volume of natural gas and NGL sales. The results for the three months ended March 31, 2012 also include three months of throughput on our Alabama pipeline and gathering system that we acquired effective September 1, 2011.

Operations and maintenance expense. The expenses related to operating and maintaining our assets for the three months ended March 31, 2012 were $7.2 million, compared to $4.8 million for the three months ended March 31, 2011. This increase of $2.4 million is due primarily to the inclusion of three months of expenses relating to the operation of our Alabama pipeline and gathering system that we acquired effective September 1, 2011, the effect of variations in timing of expenses for pipeline integrity and compression maintenance costs, higher variable consumable costs, increased local taxes as we made investments and expanded our asset value and higher labor and benefit costs as we have added to our staffing to support our expansion plans.

General and administrative ("G&A") expenses. G&A expenses for the three months ended March 31, 2012 were $2.4 million, compared to $2.0 million for the three months ended March 31, 2011. This increase of $0.4 million was primarily due to increased employment-related expenses and support costs as we continued to build our corporate and support infrastructure.

Depreciation and amortization expense. Depreciation and amortization expense for the three months ended March 31, 2012 was $3.7 million, compared to $2.8 million for the three months ended March 31, 2011. The increase in depreciation and amortization expense is primarily due to the EAI acquisition and the significant growth capital expenditures made during the second half of 2011 and the first quarter of 2012.

Interest expense. For the three months ended March 31, 2012, interest expense was $1.8 million, compared to $1.6 million for the three months ended March 31, 2011. This increase is due in part to the unrealized loss of $0.2 million that we incurred to terminate our interest rate cap. We benefited from the capitalization of $1.1 million of interest expense as part of the construction costs of our new facilities during the three months ended March 31, 2012, thus reducing the impact of higher borrowing levels during the three months ended March 31, 2012, compared to the three months ended March 31, 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Volume and overview. Our average throughput volume of natural gas increased by 7.6% to 506,975 MMBtu/d in 2011, compared to 471,265 MMBtu/d in 2010. Our South Texas throughput volumes in 2011 increased by 5.9% compared to the same period in 2010. This increase in our South Texas throughput volumes reflects stronger activity through our system in the last four months of 2011, in part as a result of new contracts that we executed to support the completion of our McMullen pipeline extension. Our volumes in South Texas were unfavorably impacted by two events during the year ended December 31, 2011: (i) the shutdown of our Gregory processing plant for 31 days during June and July in order to repair a dehydrator unit; and (ii) a 31 day shutdown in September and

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October by Formosa at its processing plant in order to complete an expansion construction project, which forced us to shutdown natural gas supply to, and interrupted processing at, this facility. Our Mississippi and Alabama throughput volumes were up 12.1% for the year ended December 31, 2011 compared to the year ended December 31, 2010. This increase is due to the inclusion of four months of throughput on our pipeline and gathering system that we acquired in connection with the EAI acquisition. Without this additional volume, our average daily throughput volumes would have declined by 17.2% for our Mississippi and Alabama assets for the year ended December 31, 2011 compared to the year ended December 31, 2010. This decline was due primarily to lower demand from the South Mississippi Electric Power Association, or SMEPA, and the impact on our Delta Pipeline resulting from the flooding of the Mississippi River in the second quarter of 2011. For NGLs, the average volume delivered per day for 2011 was 215.5 Mgal, compared to 233.4 Mgal for 2010, a decrease of 7.7%. This decrease was due in part to the shutdown of our Gregory processing plant for 31 days in June and July 2011 and severe cold weather in February and March 2011. Without the Gregory processing plant shutdown, we estimate our average daily volume delivered would have been 225.4 Mgal for 2011.

Our gross operating margin for the year ended December 31, 2011 improved to $62.6 million compared to $59.3 million for the year ended December 31, 2010, an increase of 5.5%, primarily as a result of slightly higher treating / producer fee-based revenues as well as a greater price spread between NGL and natural gas prices and the benefit of four months of operations from the EAI acquisition, which more than offset lower NGL volumes. We estimate that our gross operating margin for the year ended December 31, 2011 was negatively impacted by $2.1 million as a result of the unexpected closure of our Gregory processing plant and the forced closures of the Formosa processing plant in September and October 2011. For part of the year, we were capacity bound by our inability to process all of the wet gas in our system. This constraint was the impetus for our future growth capital expenditure plans and the construction of the Bonnie View fractionation facility. We generated net income for the year ended December 31, 2011 of $7.5 million compared to net income of $9.7 million for the year ended December 31, 2010. This decrease was primarily due to a loss on extinguishment of debt of $3.2 million, higher operating and maintenance expenses and increased depreciation and amortization expense, partially offset by lower interest expense. Adjusted EBITDA decreased by 6.3% to $28.9 million for the year ended December 31, 2011 compared to $30.9 million for the year ended December 31, 2010, due primarily to higher operating and maintenance expenses and increased G&A expenses, partially offset by an improvement in gross operating margin.

Revenue. Our total revenue for the year ended December 31, 2011 was $523.1 million, compared to $498.7 million for the year ended December 31, 2010. This increase of $24.4 million, or 4.9%, was primarily due to the inclusion of four months of results from the EAI acquisition, which contributed $11.0 million in revenues, improved prices for NGL products and higher fee-based revenues, partially offset by lower NGL volumes. We realized average natural gas and NGL prices of $4.05/MMBtu and $1.35/gal, respectively, for the year ended December 31, 2011 compared to $4.42/MMBtu and $1.10/gal, respectively, for the year ended December 31, 2010.

Cost of natural gas and liquids sold. Our cost of natural gas and liquids sold for the year ended December 31, 2011 was $460.6 million compared to $439.4 million for the year ended December 31, 2010. This increase was due to the increased natural gas throughput in South Texas and, in part, to the inclusion of four months of throughput on our Alabama pipeline and gathering system that we acquired effective September 1, 2011.

Operations and maintenance expense. The expenses related to operating and maintaining our assets for the year ended December 31, 2011 were $24.7 million compared to $21.1 million for the year ended December 31, 2010. This increase of $3.6 million was primarily due to the inclusion of four months of expenses relating to the operation of the pipeline and gathering system we acquired in connection with the EAI acquisition, increased expenditures on pipeline integrity, higher expenses for chemicals used at our facilities and building up our engineering capability to support our expansion plans.

General and administrative ("G&A") expenses. G&A expenses for the year ended December 31, 2011 were $8.9 million compared to $7.3 million for the year ended December 31, 2010. This increase of $1.6 million was primarily due to increased employment-related expenses as we continued to build up our corporate infrastructure.

Transaction costs. We incurred approximately $0.2 million of one-time expenses, including legal, consulting and professional fees for the year ended December 31, 2011 in connection with the acquisition of EAI on September 1, 2011. This compares to $0.1 million of transaction costs for bank fees related to our acquisition of the Crosstex assets that we incurred for the year ended December 31, 2010.

Depreciation and amortization expense. Depreciation and amortization expense for the year ended December 31, 2011 was $12.3 million compared to $11.0 million for the year ended December 31, 2010 primarily as a result of the EAI acquisition and growth capital expenditures made during 2011.

Loss on extinguishment of debt. For 2011, we recorded a loss on the extinguishment of debt of $3.2 million relating to the write off of deferred financing fees on our previous credit agreement as a result of entering into our existing credit agreement on June 10, 2011.

Interest expense. For the year ended December 31, 2011, interest expense was $5.4 million, compared to $10.0 million for the year ended December 31, 2010. This decrease was primarily due to $1.8 million of interest expense being capitalized in 2011 as part of construction costs of our new facilities, the lower amortization of deferred financing fees in 2011 compared to 2010, and favorable interest rate margins obtained under an amendment to our existing credit agreement that we entered into on December 30, 2010. For the years ended December 31, 2011 and December 31, 2010, our average effective interest rate, as calculated for financial reporting purposes, was 4.8% and 8.9%, respectively.

Year Ended December 31, 2010 Compared to the 2009 Successor Period and the 2009 Predecessor Period

Volume and overview. Our average throughput volume of natural gas for the year ended December 31, 2010 was 471,265 MMBtu/d compared to 492,350 MMBtu/d and 592,243 MMBtu/d for the 2009 Successor Period and the 2009 Predecessor Period, respectively, reflecting the effect of lower natural gas prices and a decline in the Texas land rig count during 2010. We began to experience a decline in demand for our services in the South Texas market in the fourth quarter of 2009 with a further deterioration in 2010. As a result, our South Texas throughput volumes declined by 17.4% over the same time period. Our Mississippi and Alabama throughput volumes were down 5.0% for the year ended December 31, 2010, compared to the 2009 Successor Period and 2009 Predecessor Period combined, due to declines in both producer supply and demand from our power generation, industrial and utility customers. We added approximately 18,000 MMBtu of throughput volume per day by the commissioning of our Delta Pipeline in the third quarter of 2009. Without this additional volume, our throughput volumes would have declined by 18.6%, primarily as a result of reduced drilling by producers prompted by lower natural gas prices. For NGLs, the average volume delivered per day for the year ended December 31, 2010 was 233.4 Mgal compared to 225.5 Mgal and 241.8 Mgal for the 2009 Successor Period and the 2009 Predecessor Period, respectively. The decrease in average NGL volumes delivered per day for the year ended December 31, 2010 as compared to the 2009 Successor Period was due to a ten-day shutdown of the Gregory processing plant in September 2010 to replace certain equipment and to implement efficiency improvements at the plant.

Our gross operating margin for the year ended December 31, 2010 was $59.3 million compared to $27.6 million and $29.5 million for the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase in gross operating margin was due primarily to higher fixed fees and higher realized NGL prices. Net income for the year ended December 31, 2010 was $9.7 million compared to $4.4 million and $1.7 million for the 2009 Successor Period and 2009 Predecessor Period, respectively. The increase in net income was due primarily to lower G&A expenses than our Predecessor, gains in gross operating margin and lower transaction costs of $2.8 million, partially offset by an increase in operations and maintenance expense and higher interest expense due to our incurrence of debt in order to finance the acquisition of our initial assets on August 1, 2009. Adjusted EBITDA for the year ended December 31, 2010 was $30.9 million, compared to $16.5 million and $9.2 million for the 2009 Successor Period and 2009 Predecessor Period, respectively. This overall improvement in Adjusted EBITDA was the result of a realized gross operating margin increase and lower G&A expenses, partially offset by the increase in operations and maintenance expense.

Revenue. Our total revenue in 2010 was $498.7 million, compared to $206.6 million and $330.9 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This decrease reflects the impact of lower natural gas throughput volumes which outweighed the increase in producer fee-based revenues and the benefit of higher natural gas and NGL prices. We realized average natural gas and NGL prices of $4.42/MMBtu and $1.10/gal, respectively, for the year ended December 31, 2010, compared to $3.97/MMBtu and $1.01/gal, respectively, for the 2009 Successor Period and $3.95/MMBtu and $0.69/gal, respectively, for the 2009 Predecessor Period.

Cost of natural gas and liquids sold. Our cost of natural gas and liquids sold for 2010 was $439.4 million, compared to $179.0 million and $301.4 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. This decrease in costs reflects our lower throughput volumes of natural gas in 2010 compared to the 2009 Successor Period and 2009 Predecessor Period and an increasing portion of our contracts being fixed-fee for which we record only the fee as revenue.

Operations and maintenance expense. The expenses related to operating and maintaining our pipeline systems and processing plants were $21.1 million in 2010, compared to $7.8 million and $10.6 million for the 2009 Successor Period and the 2009 Predecessor Period, respectively. This increase reflected our additional expenditures on employees and maintenance activities to improve the overall operation of our assets that we acquired in August 2009. The primary components of our higher costs relate to $1.1 million of higher pipeline integrity costs, maintenance costs, and manpower costs, partially offset by lower leases and rents.

General and administrative expenses. G&A expenses in 2010 were $7.3 million, or $612,000 per month, compared to $3.2 million, or $645,000 per month, and $9.8 million, or $1,398,000 per month, in the 2009 Successor Period and the 2009 Predecessor Period, respectively. We had a slight decrease in the monthly run rate between 2010 and the 2009 Successor Period as we built out our finance function, made improvements to our infrastructure and created controls for our company to operate as a stand-alone entity. This decrease is primarily due to start-up costs incurred during the 2009 Successor Period, which included the payment of $1.0 million to Crosstex for the performance of transition services while we hired and trained personnel and installed new computer and software systems necessary to run our business. During the last five months of 2009 and the year ended December 31, 2010, even though we increased our headcount, incurred office lease costs and professional fees, we were able to operate our business with a lower average level of G&A expense than our Predecessor as reflected in the lower 2010 and 2009 Successor Period run rates compared to the 2009 Predecessor Period. Also, G&A expense includes a management fee of $50,000 per month that we have paid to Charlesbank since the date of our initial acquisition. Following the completion of this offering, we will no longer be required to pay this fee to Charlesbank. Please see "Conflicts of Interest and Duties."

Transaction costs. We incurred approximately $3.0 million of transaction expenses, including legal, consulting and accounting fees in the 2009 Successor Period in connection with the acquisition of our initial assets. This compares to $0.1 million of transaction costs for this acquisition for the year ended December 31, 2010.

Depreciation and amortization expense. Depreciation and amortization expense was $11.0 million in 2010, compared to $4.2 million and $7.3 million in the 2009 Successor Period and the 2009 Predecessor Period, respectively. We recorded our assets at fair value, which was greater than our Predecessor's book value of those assets, and their useful lives were increased, which had the net effect of decreasing the depreciation expense associated with our assets after the acquisition date. The decrease in depreciation and amortization expense in 2010 as compared to 2009 is attributable to the impact of these adjustments.

Interest expense. Interest expense for the year ended December 31, 2010 was $10.0 million, compared to $4.6 million and zero for the 2009 Successor Period and 2009 Predecessor Period, respectively. The primary reason for the increase is that we incurred interest expense for 12 months in 2010 but only five months in 2009 on the debt that we incurred on August 6, 2009 to fund the acquisition of our initial assets. Our Predecessor incurred no interest expense because all funding for the entity was provided on a pass-through basis by the central treasury function of the parent entity.

Liquidity and Capital Resources

Since the acquisition of our initial assets in August 2009, our sources of liquidity have included cash generated from operations, investments by Charlesbank and other members, including management, and borrowings under our credit facility.

Following the closing of this offering we expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our new credit facility; and
- issuances of debt and equity securities.

We believe that the cash generated from these sources will be sufficient to allow us to distribute the minimum quarterly distribution on all of our outstanding common and subordinated units and the corresponding distribution on our 2.0% general partner interest and to meet our requirements for working capital and capital expenditures for at least the next 12 months.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. Our working capital was $(17.3) million at March 31, 2012, compared to $(28.8) million at December 31, 2011, $4.2 million at December 31, 2010 and ($8.9) million at December 31, 2009.

The $11.5 million increase in working capital from December 31, 2011 to March 31, 2012 was primarily a result of the following factors:

- an increase in cash and cash equivalents of $12.6 million representing remaining proceeds received from the issuance of our Series B Redeemable Preferred Units during the three months ended March 31, 2012 that will be used to fund our growth expenditure plans; and
- a decrease in accounts payable of $3.1 million due to timing differences and a decrease in other current liabilities of $2.1 million; partially offset by
- a decrease in accounts receivable of $5.6 million.

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The $33.0 million decrease in working capital from December 31, 2010 to December 31, 2011 was primarily a result of our growth initiatives and related expansion capital expenditures, as reflected by the following:

- a decrease in cash and cash equivalents of $18.9 million to fund our expansion capital expenditures;
- an increase in current maturities of long-term debt of $6.0 million as we increased borrowing from our credit facility;
- an increase in accounts payable of $15.3 million reflecting our higher capital expenditures and increased natural gas purchases to support our higher revenues; partially offset by
- an increase in our accounts receivable of $6.2 million due to higher sales volumes in December 2011 compared to December 2010; and
- a decrease in interest payable of $1.8 million due to timing differences.

The $13.1 million increase in working capital from December 31, 2009 to December 31, 2010 was primarily a result of the following:

- an increase in cash and cash equivalents of $14.6 million for December 31, 2010 compared to December 31, 2009, due primarily to the borrowing of $14.2 million of cash on December 30, 2010 specifically to fund our first half 2011 expansion capital expenditures;
- a decrease of $1.0 million in the current maturities of long-term debt; partially offset by
- an increase in our interest payable of $1.6 million at December 31, 2010 as our regular quarterly payment was delayed until the following month; and
- a decrease in our accounts receivables and payables of $4.9 million and $3.8 million, respectively, reflecting the impact of lower commodity prices upon our revenues and cost of natural gas and liquids sold.

Cash Flows

The following table reflects cash flows for the applicable periods:

	Southcross Energy Predecessor	**Southcross Energy LLC**				
	Seven Months Ended	**Period from June 2, 2009 (Inception date) to December 31,**	**Year Ended December 31,**		**Three Months Ended March 31,**	
	July 31, 2009	**2009**	**2010**	**2011**	**2011**	**2012**
			(in thousands)			
Operating activities	$ 4,955	$ 10,164	$ 25,493	$ 20,007	$ 272	$ 4,638
Investing activities	(791)	(238,339)	(5,231)	(144,602)	(14,882)	(38,912)
	(4,164)	233,899	(5,663)	105,684	(4,766)	46,847

Financing activities

Three Months Ended March 31, 2012 Compared to the Three Months Ended March 31, 2011

Operating activities. Net cash provided by operating activities was $4.6 million for the three months ended March 31, 2012, compared to $0.3 million for the same period in 2011. The increase in cash provided by operating activities was primarily a result of higher net income, net of non-cash charges of $3.7 million, and an increase of $0.6 million in cash generated from changes in our operating assets and liabilities.

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Investing activities. Net cash used in investing activities was $38.9 million for the three months ended March 31, 2012, compared to $14.9 million for the three months ended March 31, 2011. The increase in cash used in investing activities was primarily the result of a significant increase in expansion capital expenditures associated with our growth activities.

Financing activities. Net cash provided by (used in) financing activities was $46.8 million for the three months ended March 31, 2012, compared to $(4.8) million for the three months ended March 31, 2011. The increase in cash provided by financing activities was primarily a result of increased net borrowings of $29.1 million under our existing credit facility and a capital contribution of $35.3 million by Charlesbank and an affiliate of Wells Fargo Securities, LLC in exchange for redeemable preferred units, partially offset by the payment of $15.3 million to retire the equity of a non-management unit-holder in the first quarter of 2012, compared to the net repayment of debt of $4.8 million in the first quarter of 2011.

Year Ended December 31, 2011 Compared to the Year Ended December 31, 2010

Operating activities. Net cash provided by operating activities was $20.0 million for the year ended December 31, 2011, compared to $25.5 million for the year ended December 31, 2010. The decrease in cash provided by operating activities was primarily a result of negative changes of $6.2 million in operating assets and liabilities related to interest payable, other non-current assets and prepaid assets, partially offset by the higher net income, net of non-cash charges of $0.7 million.

Investing activities. Net cash used in investing activities was $144.6 million for the year ended December 31, 2011 compared to $5.2 million for the year ended December 31, 2010. The increase in cash used in investing activities was primarily a result of a significant increase in expansion capital expenditures associated with our growth plans and the payment of $21.8 million for the acquisition of EAI.

Financing activities. Net cash provided by (used in) financing activities was $105.7 million for the year ended December 31, 2011 compared to ($5.7) million for the year ended December 31, 2010. The change in cash provided by financing activities was primarily a result of increased net borrowings of $93.3 million under our existing credit facility and a capital contribution of $15.0 million by Charlesbank and other existing investors, partially offset by the payment of debt amendment costs of $2.7 million in 2011 compared to the net repayment of debt of $4.9 million and payment of debt financing costs of $0.8 million in 2010.

Year Ended December 31, 2010 Compared to the 2009 Successor Period and the 2009 Predecessor Period

Operating activities. Net cash provided by operating activities was $25.5 million for the year ended December 31, 2010 compared to $10.2 million and $5.0 million for the 2009 Successor Period and 2009 Predecessor Period, respectively. The increase in cash provided by operating activities of $10.4 million for 2010, compared to the 2009 Successor Period and the 2009 Predecessor Period was primarily the result of higher net income, net of non-cash charges of $5.0 million reflecting increased income from operations and net positive charges in operating assets and liabilities of $5.4 million related to interest payable and prepaid assets.

Investing activities. Net cash used in investing activities was $5.2 million for the year ended December 31, 2010 compared to $238.3 million and $0.8 million for the 2009 Successor Period and 2009 Predecessor Period, respectively. The decrease in cash used in investing activities for the year ended December 31, 2010 compared to the 2009 Successor Period was primarily a result of our acquisition of our initial assets in August 2009 for cash consideration of $233.8 million. In the 2009 Predecessor Period, the parent of our Predecessor limited investing activities, reflecting the parent entity's intent to sell these assets and therefore resulting in capital expenditures of only $0.8 million.

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Financing activities. Net cash provided by (used in) financing activities was ($5.7) million for the year ended December 31, 2010, compared to $233.9 million and ($4.2) million for the 2009 Successor Period and 2009 Predecessor Period, respectively. The change in cash provided by (used in) financing activities was primarily a result of net borrowings under our credit facility of $125.0 million and a capital contribution of $116.9 million by Charlesbank and $3.0 million from other existing investors in connection with our acquisition of our initial assets and funding our initial working capital requirements in August 2009. During the year ended December 31, 2010, we made $19.1 million in repayments under the term loan portion of our existing credit facility and borrowed an additional $14.2 million. In the 2009 Predecessor Period, changes in advances to the Predecessor's former owner resulted in cash used in financing activities of $4.2 million.

Off-Balance Sheet Arrangements

We do not have any material off-balance sheet arrangements.

Capital Requirements

The midstream energy business is capital-intensive, requiring significant investment for the maintenance of existing assets and the acquisition or development of new systems and facilities. We categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity; or

- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long-term.

For the year ended December 31, 2011, our capital expenditures totaled $156.0 million. We estimate that 3.4% of our capital expenditures in this period, or $5.3 million, were maintenance capital expenditures and that 96.6% of our capital expenditures, or $150.7 million, were expansion capital expenditures. Although we classified our capital expenditures as maintenance capital expenditures and expansion capital expenditures, we believe those classifications approximate, but do not necessarily correspond to, the definitions of maintenance capital expenditures and expansion capital expenditures under our partnership agreement. We believe our maintenance capital expenditures on our assets have exceeded those of our Predecessor because it had determined to focus its maintenance capital expenditure budget on assets in its other areas of operation rather than on maintaining the assets we acquired from it. It has been customary in the regions in which we operate for producers to bear the cost of well connections, but we cannot be assured that this will be the case in the future.

We expect that in the future, as was the case for the year ended December 31, 2011, most of our expansion capital expenditures will be funded through borrowings under our new credit facility that we expect to enter into in connection with this offering.

Our 2011 expansion capital expenditures of $150.7 million consisted of the following:

- $64.4 million of the total $97.0 million forecasted for the construction of our Woodsboro processing plant;

- $29.8 million for the construction of the McMullen pipeline extension;

- $24.8 million for the acquisition of EAI and the Tauber pipeline;

- $10.9 million for the installation of enhancements at our Gregory processing plant;

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- $3.1 million of the total $32.0 million forecasted for the construction of our Bonnie View fractionator; and
- $17.7 million for pipeline projects in South Texas and Mississippi.

We are forecasting $117.1 million in capital expenditures for the year ending December 31, 2012, of which $109.8 million represents expansion capital expenditures and $7.3 million represents maintenance capital expenditures. In the first quarter of 2012, we incurred expansion capital expenditures of $45.3 million and maintenance capital expenditures of $0.3 million. Our 2012 budgeted expansion capital expenditures of $109.8 million consist of the following:

- $32.6 million to complete the construction of our Woodsboro processing plant;
- $28.9 million to complete the construction of our Bonnie View fractionator;
- $10.2 million to complete the construction of pipelines to connect throughput volumes to the Bonnie View fractionator and then to NGL markets;
- $30.8 million to construct natural gas pipelines and add compression to enable growth of total system throughput volumes; and
- $7.3 million to construct other growth projects.

We anticipate that we will continue to make significant expansion capital expenditures in the future. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives. We expect that our future expansion capital expenditures will be funded by borrowings under our new credit facility and the issuance of debt and equity securities.

Integrity Management

When we acquired our operating assets from Crosstex, we inherited an ongoing integrity management program required under regulations of the U.S. Department of Transportation, or DOT. These regulations require transportation pipeline operators to implement continuous integrity management programs over a seven-year cycle. Our current baseline program will be complete in 2012. In connection with the acquisition of our initial assets from Crosstex we initiated a comprehensive review of the program and concluded that there were 40.3 miles of high consequence areas, or HCAs, in addition to those identified by our Predecessor that required further testing pursuant to DOT regulations. We expect to incur under $0.3 million in integrity management expenses in 2012 associated with these HCAs and per regulatory requirements to complete the current integrity management program. Beginning in 2013 we will reassess our current integrity management program during which we expect to incur an average of approximately $1.7 million in integrity management expenses per year over the course of the seven-year cycle.

Distributions

We intend to pay a quarterly distribution at an initial rate of $ per unit, which equates to an aggregate distribution of $ million per quarter, or $ million on an annualized basis, based on the number of common and subordinated units anticipated to be outstanding immediately after the closing of this offering, as well as our 2.0% general partner interest. We do not have a legal obligation to make distributions except as provided in our partnership agreement.

Our Credit Facility

On June 10, 2011, we entered into a Restated Credit Agreement with a syndicate of lenders led by Wells Fargo Bank, N.A. The credit facility, with a maturity of June 10, 2016, is composed of a

$175.0 million term loan facility and a $150.0 million revolving credit facility, which includes a sub-limit of up to $50.0 million for letters of credit. All our property is pledged as collateral under this credit facility. The terms of the credit facility contain customary covenants, including, among others, those that restrict our ability to make or limit certain payments, distributions, acquisitions, loans, or investments, incur certain indebtedness or create certain liens on our assets. As of December 31, 2011, we were in compliance with the covenants in our existing credit facility.

On February 7, 2012, we entered into the First Amendment to the Restated Credit Agreement. We entered into this amendment to satisfy our operating and capital plans prior to the completion of this offering and the transactions contemplated by this prospectus. We obtained modifications to the covenants to reflect our need for capital expansion to support our growth plans, including the construction of our Woodsboro processing plant and Bonnie View fractionation site. The term loan commitment and revolver loan capacity have not been changed by this amendment, although pricing has been modified to reflect the now permitted higher leverage ratio.

In connection with our initial public offering, we expect to replace our existing credit facility and enter into a new credit facility that will include a $ million revolver. The revolver will mature in , and borrowings will bear interest at a variable rate per annum equal to the lesser of LIBOR or the Base Rate, as the case may be, plus the Applicable Margin (LIBOR, Base Rate and Applicable Margin each will be defined in the credit agreement that evidences our new credit facility). Under our new credit facility, in addition to the uses described in "Use of Proceeds," we expect that borrowings may be used for (i) the refinancing and repayment of certain existing indebtedness, (ii) working capital and other general partnership purposes and (iii) capital expenditures. Borrowings under our new credit facility will be secured by a first-priority lien on and a security interest in substantially all of our assets. The credit agreement that evidences our new credit facility will contain customary covenants, including restrictions on our ability to incur additional indebtedness, make certain investments, loans or advances, make distributions to our unitholders, make dispositions or enter into sales and leasebacks, or enter into a merger or sale of our property or assets, including the sale or transfer of interests in our subsidiaries.

The events that constitute an Event of Default under our new credit agreement are expected to be customary for loans of this size and type.

Credit Risk and Customer Concentration

We examine the creditworthiness of third-party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. A significant percentage of our revenues and margin is attributable to a relatively small number of customers. Formosa Hydrocarbons Co, Inc. and Sherwin Alumina Company each represents more than 10% of our approximately $523.1 million in consolidated revenue for the year ended December 31, 2011, accounting for $108.8 million (20.8%) and $81.2 million (15.5%), respectively, of our consolidated revenue for that year. Our top 10 customers represented 73.1% of our consolidated revenue for the year ended December 31, 2011. Although we have gathering, processing or transmission contracts with each of these customers of varying duration, if one or more of these customers were to default on their contractual obligations or if we were unable to renew our contract 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 any of these situations, our gross operating margin and cash flows and our ability to make cash distributions to our unitholders may be adversely affected. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our gross operating margin.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2011:

Contractual Obligation(1)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More than 5 Years
			(in thousands)		
Long-term debt(2)	$ 236,904	$ 24,751	$ 47,614	$ 164,539	$
Vehicle fleet lease	1,198	402	711	85	
Office lease	1,583	321	673	589	
Total	$ 239,685	$ 25,474	$ 48,998	$ 165,213	$

(1) We have not included Holdings' obligations for its preferred units and redeemable preferred units because these units are an obligation of Holdings and are not a part of our capitalization.

(2) Amounts relate to our existing credit agreement that will be repaid in full in connection with this offering. Please read "Use of Proceeds." Includes interest calculated at the effective interest rate as of December 31, 2011 of 3.6%, which was held constant for all periods.

Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Natural gas and NGL prices are impacted by changes in the supply and demand for natural gas and NGLs, as well as market uncertainty. For a discussion of the volatility of natural gas and NGL prices, please read "Risk Factors." Adverse effects on our cash flow from reductions in natural gas and NGL product prices could adversely affect our ability to make distributions to unitholders. We manage this commodity price exposure through an integrated strategy that includes management of the commercial terms of our contract portfolio by entering into fee-based or fixed-spread arrangements whenever possible and the use of swing swaps. Swing swaps are generally short term in nature (one month) and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. We have not entered into any long-term derivative contracts to manage our exposure to commodity price risk. Natural gas prices, however, can also affect our profitability indirectly by influencing the level of drilling activity in our areas of operation. We are a net seller of NGLs, and as such our financial results are also exposed to fluctuations in NGL pricing.

We continually and proactively monitor our commodity exposure and compare this exposure to our stated hedging strategy.

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness associated with our credit facility. On March 2, 2012, we entered into an interest rate swap contract with Wells Fargo Bank, N.A. effective March 30, 2012 for $150.0 million notional amount of our debt. The contract effectively caps our LIBOR based interest rate exposure on that portion of our debt at 0.54% through June 30, 2014.

The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will continue to tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on floating rate credit facilities and

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future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical increase or decrease in interest rates by 1.0% would have changed our interest expense by $1.5 million for the year ended December 31, 2011.

Impact of Seasonality

Our results of operations on our transportation assets are not materially affected by seasonality.

Critical Accounting Policies and Estimates

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

Our Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met:

- persuasive evidence of an exchange arrangement exists;
- delivery has occurred or services have been rendered;
- the price is fixed or determinable; and
- collectability is reasonably assured.

We record revenue for natural gas and NGL sales and transportation services over the period in which they are earned (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). While we make every effort to record actual volume and price data, there may be times where we need to make use of estimates for certain revenues and expenses. If the assumptions underlying our estimates prove to be substantially incorrect, it could result in material adjustments in results of operation.

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in-service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include:

- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;

changes in expected salvage values; or

significant changes in the forecast life of proved reserves of applicable gas production basins, if any.

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Measuring Recoverability of Long-Lived Assets

Long-lived assets such as property, plant and equipment are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas and NGLs. Long-lived assets with carrying values that are not expected to be recovered through forecast future cash flows are written-down to their estimated fair values. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset as a going concern. We determine the fair value of the asset by using our weighted average cost of capital to discount the present value of the future cash flows. The carrying value of a long-lived asset is not recoverable if it exceeds the present value of the estimated future cash flows expected to result from the use and eventual disposition of the asset. An impairment charge will be recorded to reduce the carrying amount to its estimated fair value.

Accounting for Contingencies

Our financial results may be affected by judgments and estimates related to loss contingencies. Litigation contingencies may require significant judgment in estimating amounts to accrue. We accrue liabilities for litigation contingencies when such liabilities are considered probable of occurring and the amount is reasonably estimable.

INDUSTRY OVERVIEW

General

The midstream natural gas industry provides the link between the exploration and production of natural gas and the delivery of that natural gas and its by-products to industrial, commercial and residential end-users. The principal components of the business consist of gathering, compressing, treating, dehydrating, processing, fractionating, transporting and marketing natural gas and natural gas liquids, or NGLs. The midstream industry is generally characterized by regional competition based on the proximity of gathering and pipeline systems and processing and treating plants to natural gas producing wells. Companies within this industry provide services at various stages along the natural gas value chain by gathering natural gas from producers at the wellhead, separating the hydrocarbons into dry gas (primarily methane) and NGLs, and then routing the separated dry gas and NGL streams to the next intermediate stage of the value chain or to transmission pipelines for delivery to end-markets. Transmission consists of moving pipeline-quality natural gas from these gathering systems and plants for delivery to customers. Marketing consists of the purchase and then sale of natural gas and NGLs to end-use customers.

The following diagram illustrates the various components of the natural gas value chain and the extent of our current operations:

Midstream Services

The range of services utilized by midstream natural gas service providers are generally divided into the following seven categories:

Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport natural gas from the wellhead to a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow for additional production and well connections without significant incremental capital expenditures.

Compression. Gathering systems are operated at design pressures that enable the maximum amount of production to be gathered from connected wells. Through a mechanical process known as compression, volumes of natural gas at a given pressure are compressed to a sufficiently higher pressure, thereby allowing those volumes to be delivered into a higher pressure downstream pipeline to be brought to market. Since wells produce at progressively lower field pressures as they age, it becomes necessary to add additional compression over time near the wellhead to maintain throughput across the gathering system.

Treating and Dehydration. Another process in the midstream value chain is treating and dehydration, a step that involves the removal of impurities such as water, carbon dioxide, nitrogen and hydrogen sulfide that may be present when natural gas is produced at the wellhead. These impurities must be removed for the natural gas to meet the specifications for transportation on long-haul intrastate and interstate pipelines. Moreover, end users will not purchase natural gas with a high level of these impurities. To meet downstream pipeline and end-user natural gas quality standards, the natural gas is dehydrated to remove the saturated water and is chemically treated to separate the impurities from the gas stream.

Processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of other NGLs, which are heavier hydrocarbons that are found in some natural gas streams. Even after treating and dehydration, most natural gas is not suitable for long-haul intrastate and interstate pipeline transportation or commercial use because it contains NGLs, as well as natural gas condensate. This natural gas, referred to as liquids-rich natural gas, must be processed to remove these heavier hydrocarbon components, as well as natural gas condensate. NGLs not only interfere with pipeline transportation, but are also valuable commodities once removed from the natural gas stream. The removal and separation of NGLs usually takes place in a processing plant using industrial processes that exploit differences in the weights, boiling points, vapor pressures and other physical characteristics of NGL components.

Fractionation. The mixture of NGLs that results from natural gas processing is generally comprised of the following five components: ethane, propane, normal butane, iso-butane and natural gasoline. This mixture is often referred to as y-grade or raw make NGL. Fractionation is the process by which this mixture is separated into the NGL components prior to their sale to various petrochemical and industrial end users.

Natural Gas Transmission. Once the raw natural gas has been treated and processed, the remaining natural gas, or residue natural gas, is transported to end users. The transmission of natural gas involves the movement of pipeline-quality natural gas from gathering systems and processing facilities to wholesalers and end users, including industrial plants and LDCs. LDCs purchase natural gas on interstate and intrastate pipelines and market that natural gas to commercial, industrial and residential end users. Transmission pipelines generally span considerable distances and consist of large-diameter pipelines that operate at higher pressures than gathering pipelines to facilitate the transportation of greater quantities of natural gas. The concentration of natural gas production in a few regions of the U.S. generally requires transmission pipelines to cross state borders to meet national demand. These pipelines are referred to as interstate pipelines and are primarily regulated by federal agencies or commissions, including the FERC. Pipelines that transport natural gas produced and consumed wholly within one state are generally referred to as intrastate pipelines. Intrastate pipelines are primarily regulated by state agencies or commissions.

NGL Products Transportation. Once the NGL stream has been separated from the natural gas stream, and separated into products through fractionation, the resulting NGL products are then transported to downstream NGL networks or directly to end users.

U.S. Natural Gas Fundamentals

Natural gas is a critical component of energy consumption in the United States. According to the EIA, annual consumption of natural gas in the United States increased from approximately 22.9 Tcf in 2009 to approximately 23.8 Tcf in 2010, an increase of approximately 3.9%. Consumption continued to increase in 2011 to 24.4 Tcf, a 2.5% increase from 2010. The EIA expects total annual domestic natural gas consumption to rise from 24.4 Tcf in 2011 to 27.2 Tcf in 2035.

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In order to maintain current levels of U.S. natural gas supply and to meet the projected increase in demand, new sources of domestic natural gas must continue to be developed to offset the decline rates of existing production. Over the past several years, a fundamental shift in U.S. natural gas production has emerged with the growing contribution of natural gas from unconventional resources, defined by the EIA as natural gas produced from shale formations and coalbeds. The primary factors driving this shift are the emergence of unconventional natural gas plays and advances in technology that have allowed producers to cost-effectively extract significant volumes of natural gas from these plays. The development of these unconventional sources offsets declines in other U.S. natural gas supply, meeting growing consumption and lowering the need for imported natural gas.

According to the EIA:

- The industrial and electricity generation sectors are the largest users of natural gas in the United States, accounting for approximately 58% of the total natural gas consumed in the United States during 2010;

- Annual industrial natural gas demand is expected to grow sharply in the near term, from 6.8 Tcf in 2011 to 8.2 Tcf in 2020 as a result of an expected recovery in industrial production;

- In 2010, the end-user commercial and residential sectors accounted for approximately 33% of the total natural gas consumed in the United States; and

- During the five years ending December 31, 2010, the United States has on average consumed approximately 23.0 Tcf per year, with average annual domestic marketed production of approximately 21.0 Tcf during the same period.

The graph below represents projected U.S. natural gas production versus U.S. natural gas consumption through the year 2035.

Source: Energy Information Administration.

BUSINESS

Overview

We are a growth-oriented limited partnership that was formed by members of our management team and Charlesbank to own, operate, develop and acquire midstream energy assets. We provide natural gas gathering, processing, treating, compression and transportation services and NGL fractionation services to our producer customers, primarily under fixed-fee and fixed-spread contracts, and we also source, purchase, transport and sell natural gas and NGLs to our power generation, industrial and utility customers. Our assets are located in South Texas, Mississippi and Alabama. Our South Texas assets, which consist of approximately 1,445 miles of pipeline and two processing plants and accounted for approximately 77% of our revenues for the year ended December 31, 2011, operate in or within close proximity to the Eagle Ford shale region, which has experienced a strong increase in investment and drilling activity by exploration and production companies in recent years. Based on industry data compiled by Smith Bits, a subsidiary of Smith International, Inc., approximately 14.2% of all drilling rigs in the United States were operating in the Eagle Ford shale region as of May 25, 2012. We expect this heightened Eagle Ford shale activity, as well as activity in the frequently overlying Olmos tight sand formation, will result in higher throughput on our systems and opportunities to expand our asset base over the next several years. Our Mississippi and Alabama assets, which consist of approximately 626 and 519 miles of pipeline, respectively, are strategically positioned to provide transportation of natural gas to our power generation, industrial and utility customers as well as to unaffiliated interstate pipelines. We expect to grow our business and distributable cash flow by expanding the capacity and efficiency of our assets and by making selective acquisitions, such as our acquisition of EAI in September 2011.

South Texas

In August 2009, we acquired approximately 1,322 miles of pipeline and 33,800 horsepower of compression in South Texas from Crosstex. The assets in our South Texas region are located between Houston and Freer, a city that is located approximately 50 miles west of Corpus Christi. These assets currently consist of approximately 1,445 miles of pipeline ranging in diameter from 2" to 20" with an estimated design capacity of 590 MMcf/d. Our South Texas assets also include 28 compressors with total compression of approximately 35,500 horsepower, two processing plants with total processing capacity of 185 MMcf/d and contracted third-party processing capacity of 83 MMcf/d, two treating plants and one fractionator. The systems in this region had an average throughput of 275 MMcf/d in 2011 and the processing plants processed an average of 75 MMcf/d during that period.

Mississippi and Alabama

In August 2009, we acquired approximately 626 miles of pipeline and 2,200 horsepower of compression in Mississippi from Crosstex. 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 currently consist of approximately 626 miles of pipeline ranging in diameter from 2" to 20" with an estimated design capacity of 345 MMcf/d. During the year ended December 31, 2011, the system had an average throughput of 87 MMcf/d. The system has the capability to receive natural gas from three unaffiliated interstate pipelines to supplement supply on the system. In August 2009, we acquired approximately 125 miles of pipeline and 2,992 horsepower of compression in Alabama from Crosstex. The assets in our Alabama region are located in northwest and central Alabama and, following the EAI acquisition, which consisted of 388 miles of pipeline and 21,545 horsepower of compression, consist of 519 miles of pipeline ranging in diameter from 2" to 16." The system has an estimated design capacity of 375 MMcf/d and, in 2011, had an average throughput of 120 MMcf/d assuming the EAI acquisition was effective as of January 1, 2011.

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Our Growth Drivers

We seek to identify and pursue economically attractive organic expansion and third-party acquisition opportunities that leverage our existing assets and enhance strategic relationships with our customers. We currently expect that opportunities in the Eagle Ford shale area will be a primary driver of our near-term growth, particularly producer activity in the area we define as our "Eagle Ford pipeline catchment area," which consists of Bee, DeWitt, Karnes, LaSalle, Live Oak, McMullen and Webb Counties. We believe that the growth potential associated with the Eagle Ford shale area is supported by the recent increase in the number of drilling permits issued, drilling rig counts and production volumes in this area. As illustrated in the table below, our Eagle Ford pipeline catchment area has experienced increasing production over the last three years.

	Natural Gas (MMcf/d)	Percent Change from Prior Period
2008	1,026.4	
2009	1,003.8	(2.2)%
2010	1,133.4	12.9%
2011	1,435.0	26.6%

According to the TRRC, drilling permits with the objective of the Eagle Ford shale formation increased from 26 in 2008 to 2,826 in 2011, which further supports our belief in this area's growth potential. The growth in activity is further evidenced by the number of drilling rigs operating in our Eagle Ford pipeline catchment area, which increased approximately 7.7 times from the third quarter of 2009 to the fourth quarter of 2011.

In evaluating assets and businesses for acquisition, we look for strategic and accretive transactions that will be complementary to our existing asset base or that we expect will provide attractive returns in new operating regions. Our management and sponsor have a strong history of successful third party acquisitions, dating back to the formation of Regency Gas Services in 2002.

Commenced or Recently Completed Acquisitions and Growth Projects. From January 1, 2011 through June 30, 2012, we commenced or completed the major acquisitions and growth projects listed below involving estimated capital expenditures of $202.8 million, out of our total expansion capital expenditures of $227.5 million during the same period. Please read "Our Cash Distribution Policy and Restrictions on Distributions Estimated Cash Available for Distribution for the Twelve Months Ending June 30, 2013" for more information regarding our forecast of the estimated cash available for distribution we may realize from the projects set forth below.

Woodsboro processing plant construction. We have completed the construction of and are commencing operations of a 200 MMcf/d cryogenic processing plant in Refugio County, Texas, at an anticipated cost of $97.0 million, to expand our South Texas processing capacity.

Bonnie View fractionation plant installation. We are expanding our NGL capacity by installing an 11,500 Bbl/d fractionation facility and constructing associated pipelines to transport fractionated NGLs to market. The plant, which is expected to cost $32.0 million, will fractionate y-grade NGLs from our Woodsboro processing plant. We anticipate the plant will commence partial operation in June 2012 and be fully operational in August 2012.

Gregory processing plant enhancements. We reactivated an idle train at our Gregory processing plant in South Texas, upgraded existing equipment and added new equipment to enhance our liquids recovery performance for both trains. This project, which cost $10.9 million, increased the plant's processing capacity from 85 MMcf/d to 135 MMcf/d while improving ethane recoveries from the plant. The project was completed in October, 2011.

Tauber pipeline acquisition. On July 1, 2011, we acquired 56 miles of former Tennessee Gas Pipeline lateral pipelines near our Gregory processing plant in South Texas. This $3.0 million acquisition added a residue gas outlet for our new plant capacity and enabled us to expand sales

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of gas to local area customers. This acquisition enabled us to generate increased sales volumes, but its primary benefit is an expanded outlet for additional residue gas resulting from our Gregory processing plant enhancements described above and our new Woodsboro processing plant.

EAI acquisition. Effective September 1, 2011, we acquired EAI, an intrastate natural gas pipeline system and gathering system in northwest and central Alabama that averaged approximately 107 MMcf/d of throughput volume during the last four months of 2011 for a purchase price of $21.8 million. The acquisition significantly expanded our ability to service markets and suppliers in this region.

McMullen pipeline extension. On September 1, 2011, we completed construction of a 25-mile liquids-rich natural gas extension on our South Texas system to connect acreage in the Eagle Ford shale liquids-rich natural gas area. We have already contracted with two producers with a minimum throughput guarantee for five years. This extension cost $29.8 million and added approximately 115 MMcf/d of throughput capacity to our South Texas assets.

SMEPA pipeline expansion. Effective April 1, 2011, we constructed a nine mile, 12" diameter pipeline that connects with the Southeast Supply Header in Jones County, Mississippi and provides us with additional capacity to supply SMEPA's Moselle generation facility. This project cost $8.3 million and added 130 MMcf/d of delivery capacity to our Mississippi pipeline assets.

Our forecast for the twelve months ending June 30, 2013 includes the capital expenditures and benefits of the following projects:

- constructing 21 miles of new pipeline to bring additional supply from DeWitt and Karnes Counties in the Eagle Ford shale area to our Woodsboro processing plant;
- constructing a dry gas line near Petronila, Texas to enhance deliveries to the Corpus Christi area;
- increasing the capacity of our Bonnie View fractionator; and
- adding compression to our South Texas system in order to increase natural gas throughput to our Woodsboro processing plant.

The following table provides a summary of the actual or estimated completion date and capital expenditures associated with the growth projects identified above.

Growth Drivers	**Region**	**Actual / Estimated Completion Date**	**Capital Expenditures for the Year Ended December 31, 2011**	**Estimated Percentage of Total Project Expenditures**	**Capital Expenditures for the Six Months Ended June 30, 2012**	**Estimated Percentage of Total Project Expenditures**	**Capital Expenditures for the Twelve Months Ending June 30, 2013**	**Estimated Percentage of Total Project Expenditures**	**Total Capital Expenditures**
(dollars in millions)									
SMEPA pipeline expansion	Mississippi	April 2011	$ 8.3	100%		100%		100%	$ 8.3
Tauber and EAI pipeline systems acquisitions	Mississippi / Alabama	August 2011	24.8	100%		100%		100%	24.8
McMullen pipeline extension	South Texas	September 2011	29.8	100%		100%		100%	29.8
Gregory processing plant enhancements	South Texas	September 2011	10.9	100%		100%		100%	10.9
South Texas pipeline expansion	South Texas	December 2011	9.4	100%		100%		100%	9.4

Woodsboro processing plant construction	South Texas	June 2012	64.4	66.4%	$ 32.6	100%		100%	97.0
NGL and gas residue pipeline extensions	South Texas	July 2012		0.0%	10.2	100%		100%	10.2
Bonnie View fractionation plant installation	South Texas	August 2012	3.1	9.7%	28.9	100%		100%	32.0
Dry gas pipeline expansion to Corpus Christi market	South Texas	December 2012		0.0%	0.5	8.3%	$ 5.5	100%	6.0
Pipeline compression addition	South Texas	December 2012		0.0%		0.0%	2.8	100%	2.8
Bee pipeline extension	South Texas	January 2013		0.0%	2.0	9.1%	20.0	100%	22.0
Bonnie View fractionation facility capacity enhancement	South Texas	January 2013		0.0%	2.6	35.6%	4.7	100%	7.3
			$ 150.7		$ 76.8		$ 33.0		$ 260.5

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Please read "Our Cash Distribution Policy and Restrictions on Distributions Assumptions and Considerations Capital Expenditures" for more information regarding our anticipated capital expenditures for the twelve months ending June 30, 3013. At the closing of this offering, we expect to have availability under our new credit facility to fund the expenditures contemplated by our capital expenditures budget during our forecast period.

Future Growth Projects. We are actively pursuing new sources of natural gas supply and market demand to increase the throughput on our gathering and pipeline systems, our processing plants, on our transmission systems and to our power generation, industrial and utility customers. As we further extend our pipeline and gathering system into the Eagle Ford shale area, we are engaged in active discussions with current and prospective customers regarding our ability to serve their future needs for natural gas gathering, processing, treating, compression, transportation and any other related services. Furthermore, we believe that the Eagle Ford shale area is poised to yield significant production and volume growth in the coming years, especially in the "liquids-rich natural gas" area where the economics of producing natural gas and the associated liquids are increasingly attractive.

We believe that our physical assets are well-positioned to take advantage of these dynamics. In this regard, we are pursuing the growth opportunities listed below:

- constructing approximately 32 miles of pipeline to transport additional liquids-rich natural gas to fill our available processing capacity at our Woodsboro and Gregory processing plants; and

- adding a second processing train at our Woodsboro processing plant in Refugio County or constructing a separate processing plant in that area.

We may not decide to pursue these projects and, therefore, the impacts of these projects are not reflected in our forecast of estimated cash available for distribution for the twelve months ending June 30, 2013 included elsewhere in this prospectus.

Business Strategies

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time by expanding the capacity and efficiency of our assets and by making selective acquisitions while ensuring the ongoing stability of our business. We expect to achieve this objective by pursuing the following business strategies:

- ***Capitalize on organic growth opportunities, with a focus on high-growth areas such as the Eagle Ford shale.*** We intend to continue to evaluate and execute midstream projects involving the gathering, processing, treating, compression and transportation of natural gas and the fractionation of NGLs that enhance our existing systems as well as our ability to aggregate supply and obtain access to premium markets for that supply. We plan to continue to focus on projects that we expect to increase our total throughput volume and generate attractive returns. A primary focus of our organic growth will be our South Texas assets located in and near the Eagle Ford shale area, a rapidly growing source of unconventional U.S. natural gas production that often features high condensate and NGL content. We have recently completed several projects in this region, including a 25-mile extension of our pipeline into McMullen County to connect to an area that contains both Eagle Ford shale gas and Olmos tight sand gas. In addition, we completed the construction of and are commencing operations of our Woodsboro processing plant in Refugio County, which we expect to be fully operational in June 2012, with 200 MMcf/d of capacity that is well-positioned to process volumes from the Eagle Ford and Olmos formations.

- ***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 and adding new volumes of natural gas supplies to our existing assets. Specifically, we plan to capture incremental processing and fractionation margins from our existing throughput and to undertake additional initiatives to enhance utilization of our assets, as well as to continue to prudently enhance cost efficiencies. For example, our new Woodsboro processing plant provides us with the means of processing existing volumes at improved profit margins compared to the margins that we currently receive under our contract with Formosa, which is scheduled to terminate in January 2013, and also provides us with the capacity, along with the Gregory processing plant expansion, to process the additional supply of natural gas volume that we anticipate from the liquids-rich Eagle Ford shale area. The planned installation of our new Bonnie View fractionator will allow us to sell NGL component products to our power generation, industrial and utility customers, which we expect will bring higher margins relative to our margins for unfractionated NGLs that we produce through our processing activities. In addition, we recently refurbished an amine treater and transferred it to our Gregory processing plant so that we can accept natural gas with higher carbon dioxide content at that plant. We believe that opportunities will continue to arise to increase total system utilization by eliminating bottlenecks, connecting new supplies of natural gas to underutilized pipes and contracting our services to other suppliers, which we believe will increase cash flows with limited incremental investment cost.

Pursue accretive acquisitions of complementary assets. We intend to pursue accretive acquisitions that strategically expand or complement our existing asset portfolio. We monitor the marketplace to identify and pursue such acquisitions, with a particular focus on regions with potential for additional near-term development. To identify potential acquisitions of businesses or assets, we seek to utilize our industry knowledge, network of customers and strategic asset base. For example, in July 2011, we acquired pipeline laterals connecting to our CCNG and Gregory systems, which provide us with additional gas marketing opportunities in South Texas as well as expanded options to market residue gas from our processing facilities. Additionally, we acquired EAI, a 388-mile gathering and intrastate pipeline system in Alabama that has increased our total system throughput in Alabama from 15 MMcf/d to over 120 MMcf/d. We intend to pursue acquisition opportunities both independently and jointly with Charlesbank.

Manage our exposure to commodity price risk. Because natural gas and NGL prices are volatile, we will continue to mitigate the impact of fluctuations in commodity prices and to generate stable cash flows. We have and will continue to target a contract portfolio that is heavily weighted towards fixed-fee and fixed-spread contracts while minimizing our direct exposure to commodity price fluctuations. We will also consider other methods of limiting commodity exposure, including the use of derivative instruments, as appropriate.

Maintain sound financial practices to ensure our long-term viability. We intend to maintain our commitment to financial discipline, which we believe will serve the long-term interests of our unitholders. Consistent with our disciplined financial approach, we generally intend to fund the long-term capital requirements for expansion projects and acquisitions through a prudent combination of equity and debt capital. Upon the consummation of this offering and the use of a portion of the proceeds to repay our existing credit facility, we anticipate that we will have access to $ million of borrowing availability under our new revolving credit facility.

Competitive Strengths

We believe that we are well-positioned to successfully execute our business strategies 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 area in South Texas, which is one of the most active drilling regions in the United States. Our geographic diversity reduces our reliance on any particular region, basin or gathering system. We believe the high 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 South Texas systems' close proximity to the Eagle Ford shale area has allowed us to execute on several recent organic capital projects in the area and to identify additional infrastructure needs adjacent to our existing systems. As of January 1, 2009, the EIA estimated that the undeveloped technically recoverable reserves of the Eagle Ford shale formation comprised 21 Tcf of natural gas. The Eagle Ford shale is currently the most active U.S. shale play with over 265 dedicated active rigs as of March 2012. According to the TRRC, natural gas production from the Eagle Ford shale area increased from 108 MMcf/d in 2010 to 243 MMcf/d in 2011. Our growth opportunities are primarily impacted by activity levels in our Eagle Ford Southcross pipeline catchment area. Our Eagle Ford Southcross pipeline catchment area includes multiple prospective production zones, including the Olmos tight sand formation, which overlays the Eagle Ford shale in areas connected by our pipeline systems. On April 6, 2012, there were 162 active rigs drilling for natural gas in our Eagle Ford Southcross pipeline catchment area, which is a fourfold increase in the number of rigs operating in that area from two years earlier. Our current activity provides us with a relationship with producers in the Eagle Ford shale 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 in and around the Corpus Christi Ship Channel.

Mississippi and Alabama: We believe we are a leading service provider in the Mississippi and Alabama regions in which we operate. Our assets provide critical supply to our power generation, industrial and utility customers accessing the wholesale markets via intrastate and interstate pipeline interconnects as well as local demand from commercial and industrial consumers. Several of the large gas-fired power plants across the southern portion of Mississippi access their primary source of natural gas through our system. Our acquisition in September 2011 of a 388-mile intrastate pipeline and gathering system in Alabama has significantly expanded our ability to service markets and suppliers in northwest and central Alabama.

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 helps to promote cash flow reliability and minimizes our direct exposure to commodity price fluctuations. Our fixed-spread contracts entail simultaneous buy and sell arrangements that enable us to lock in our profit margin with minimal commodity price risk. Some of our processing arrangements also provide us with upside potential by allowing us to benefit from rising NGL prices.

Integrated midstream value chain. We provide a comprehensive package of services to natural gas producers, including natural gas gathering, processing, treating, compression and transportation and NGL fractionation. We believe our ability to move producers' 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. We believe that this ability often provides us with the opportunity to compete favorably on price against other companies that do not provide a similar full suite of services. 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 suppliers, 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 competing companies which do not offer this range of midstream services.

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Experienced and incentivized management and operating teams. Our executive officers have an average of 34 years of 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. Most of our field operating managers and supervisors have long-standing experience operating our assets. Our senior executives have worked together in several prior midstream companies and have been pursuing opportunities in the midstream industry with Charlesbank since 2002, including founding Regency Gas Services, a midstream company that was sold to a private equity firm and served as the foundation for Regency Energy Partners LP.

Supportive sponsor with significant industry expertise. Charlesbank, the principal owner of our general partner, has substantial experience as a private equity investor in the energy and midstream sectors. Charlesbank's investment professionals have deep experience in identifying, evaluating, negotiating and financing acquisitions and investments in the midstream sector, including the formation of Regency Gas Services. We believe that Charlesbank provides us with strategic guidance, financial expertise and potential capital support that enhances our ability to grow our asset base and cash flow.

Our Sponsor

Charlesbank is a leading private equity firm with over $2.0 billion of capital under management. The firm has 20 investment professionals and offices in Boston and New York. Originally managing an investment portfolio solely for Harvard University, Charlesbank broadened its investor base in 2000 to include other institutional clients. Now investing its seventh fund since 1991, Charlesbank has funded over $2.0 billion in more than 60 portfolio companies across a wide range of industries. In 2003, Charlesbank and members of our management team cofounded Regency Gas Services, a midstream company formed through the acquisition of assets from a publicly traded energy company. Over the years, Charlesbank has built deep energy experience and proven its ability to support and finance a variety of growth projects.

Our Assets

Our assets, the majority of which we acquired from Crosstex in August 2009, consist of five gathering systems, two processing plants, two intrastate pipelines, one fractionator and ancillary assets. The following table provides information regarding our assets as of December 31, 2011 and for the year ended December 31, 2011.

	Miles	Compression (horsepower)	Approximate Design Capacity (MMcf/d)	Approximate Average Throughput (MMcf/d)(2) Year Ended December 31, 2011
Pipeline Systems				
South Texas:				
Gulf Coast	743	7,136	205	128
CCNG(1)	417	1,260	200	190(3)
Gregory	266	700	135	66
Conroe	19		50	22
South Texas Total:	1,445	9,096	590	393
Mississippi	626	2,200	345	86
Alabama	519	24,537	375	120(4)
Total:	2,590	35,833	1,310	612

(1) Includes the Tauber pipeline, which we acquired on July 1, 2011.

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(2) Approximate average throughput does not include EAI prior to our ownership, which we acquired effective September 1, 2011 and which had an average throughput of 121 MMcf/d for the year ended December 31, 2010 and 107 MMcf/d for the year ended December 31, 2011.

(3) Includes 43 MMcf/d in 2011 of gas delivered from Gregory to CCNG.

(4) Includes the full year effect of the EAI acquisition.

	Compression (HP)	Approximate Design Capacity (MMcf/d)	Approximate Average Inlet Volumes (MMcf/d) Year Ended December 31, 2010	Year Ended December 31, 2011	2011 Average Bbls/d
Processing Plants					
Gregory	17,920	135	67	66	
Conroe	8,750	50	19	22	
Fractionation Plant					
Gregory					2,700
Total:	26,670	185	86	88	2,700

We derive revenue primarily from fixed-fee and fixed-spread arrangements, both for our producer and supplier customers or our own account. For the year ended December 31, 2011, our fixed-fee and fixed-spread arrangements accounted for approximately 75.0% of our gross operating margin. Our contracts vary in duration from one month to ten years and the pricing under our contracts varies depending upon several factors, including our competitive position, our acceptance of any risk associated with a longer-term contract and our desire to recoup over the term of the contract any capital expenditures that we are required to incur in order to connect a counterparty to our pipeline system.

We continually seek new sources of natural gas supply and power generation, industrial and utility customers to increase the throughput volume on our gathering and pipeline systems, through our processing plants, on our transmission systems and to our power generation, industrial and utility customers.

South Texas

In August 2009, we acquired approximately 1,322 miles of pipeline and 33,800 horsepower of compression in South Texas from Crosstex. The assets in our South Texas region are located between Houston and Freer, a city that is located approximately 50 miles west of Corpus Christi. These assets currently consist of approximately 1,445 miles of pipeline ranging in diameter from 2" to 20" with an estimated design capacity of 590 MMcf/d. Our South Texas region also includes 28 compressors with total compression of approximately 35,000 horsepower, two processing plants with total processing capacity of 185 MMcf/d and contracted third-party processing capacity of 83 MMcf/d, two treating plants and one fractionator. The systems in this region had an average throughput of 379 MMcf/d in 2011, including the processing plants, which processed an average of 75 MMcf/d in that period. We divide our South Texas region into four asset systems:

- Vanderbilt and Gulf Coast gathering systems, which we refer to collectively as the "Gulf Coast" system;
- CCNG Transmission, which we refer to as the "CCNG" system;
- Gregory gathering system, Gregory processing plant and Gregory fractionation plant; and
- Conroe gathering system and Conroe processing plant.

The pipelines in our South Texas segment are connected to multiple producing fields, including the Eagle Ford shale area. In addition to tie-ins to our two processing plants, our gathering systems are also connected to two large processing plants owned by third parties and to a number of intrastate and interstate pipelines.

Gulf Coast System. The Gulf Coast system is located throughout 13 counties in South Texas, including parts of the Eagle Ford shale area, and consists of two major pipeline systems. The Gulf Coast system includes approximately 743 miles of pipeline ranging from 2" to 20" in diameter with an estimated design capacity of 205 MMcf/d. The system also includes 7 compressors with compression of approximately 7,136 horsepower on a combined basis. In 2011, this system had an average throughput of approximately 114 MMcf/d.

The Gulf Coast system acquires liquids-rich natural gas from over 100 producers at prices that are generally at a fixed discount to the Houston Ship Channel Index price. Carbon dioxide, if any, is primarily removed at our Nursery or DeWitt Mott treating plants. The majority of the gas is delivered to third-party processing plants, including the Formosa processing plant located in Point Comfort, Texas and the Hilcorp processing plant located in Old Ocean, Texas. Formosa is contractually obligated to accept up to 83 MMcf/d of gas from our system through the middle of January 2013 and is required to pay us the greater of (1) a fixed percentage of the value of the NGLs resulting from processing plus 100% of the value of the residue natural gas (an "upgrade" percent-of-proceeds payment) and (2) the value of the unprocessed volume of natural gas priced relative to the same index pursuant to which we acquired the natural gas (a "floor" percent-of-proceeds payment). This contract structure provides a floor margin mitigating downside risk of percent-of-proceeds producer contracts by insulating us from the exposure to scenarios in which the price we pay for the unprocessed natural gas exceeds the price of the NGL stream and the residue natural gas resulting from processing activities, while preserving for us the opportunity to generate attractive processing economics when the relative commodity prices favor processing. In the case of the Hilcorp processing plant, our customers pay us gathering fees to transport approximately 25 MMcf/d from their wells to this processing plant.

Our producer customers on the Gulf Coast system range from small independent exploration and production companies to large producers such as Chesapeake Energy and Devon Energy. Our major customer and market outlet on the system is Formosa, which provides us with both processing services and a gas sales outlet. In 2011, Formosa accounted for 66% of the revenues on our Gulf Coast system.

CCNG System. The CCNG system is located in the Eagle Ford shale area and consists of over 417 miles of transmission and gathering pipeline ranging from 2" to 20" in diameter. The system also includes one compressor with total compression of approximately 1,260 horsepower. The system has an estimated design capacity of approximately 200 MMcf/d, depending on inlet and outlet markets, and, in 2011, the system had an average throughput of 190 MMcf/d. Natural gas is supplied to this system from approximately 35 field receipt points, various treating plants and third party gathering systems and pipelines, including Texas Eastern, Kinder Morgan and Conoco Lobo. Major producers who currently supply or transport natural gas on the CCNG system include Swift Energy, EOG, Exxon, Comstock and Apache. Different portions of the CCNG system transport dry natural gas and liquids-rich natural gas. Liquids-rich gas can be transported from the extreme western end of the system to our Woodsboro and Gregory processing plants. Dry gas is brought into the dry gas portions of the system along with residue gas from the outlets of our processing plants. Gas in the system is both purchased and sold, mostly under fixed-spread arrangements, as well as transported on behalf of shippers. The CCNG system sells much of its dry natural gas in the industrial market around the city of Corpus Christi, although the system does have the ability to deliver natural gas into multiple interstate and intrastate pipelines such as the Florida Gas Transmission pipeline system, the Tennessee Gas Pipeline, the Gulf South pipeline or the Kinder Morgan pipeline for access to other interstate markets. A portion of the throughput on our CCNG system is processed at our Gregory processing plant or at the Formosa processing plant located in Point Comfort, Texas.

One major shipper, Calpine Corporation, has a firm transportation agreement with us on the CCNG system for up to 100,000 MMBtu/d until 2017. Our largest gas purchase agreements on this system are with ConocoPhillips, EOG and Comstock Oil and Gas, which accounted for 36%, 14% and 8%, respectively, of the gas purchased on this system for the year ended December 31, 2011. Our largest gas sales agreements are with Sherwin Alumina, Dow Chemical, and Valero Refining and Marketing Company, which accounted for 40%, 15%, and 9%, respectively, of our revenues on this system for the year ended December 31, 2011.

Gregory Gathering System, Processing Plant and Fractionation Plant. The Gregory gathering system is located near Corpus Christi, Texas and consists of approximately 266 miles of pipeline ranging from 4" to 18" in diameter. The system also includes one compressor with total compression of approximately 700 horsepower. This primarily onshore system operates at approximately 400 to 450 psig and gathers liquids-rich and low carbon dioxide natural gas and delivers it into our Gregory processing plant. This processing plant has total compression of approximately 17,920 horsepower. Our Gregory processing plant is a cryogenic natural gas plant comprised of two units collectively having a total capacity of 135 MMcf/d one unit with 85 MMcf/d of capacity operated continuously in 2011 while the second unit with 50 MMcf/d had been idle until it was reactivated in October 2011. During 2011, plant production was restricted due to limited access to supply on our Gregory gathering system and the lack of full NGL market availability and was therefore consequently limited to an average throughput of approximately 66 MMcf/d. Our Gregory processing plant processes natural gas from the Gregory gathering system, as well as gas originating in our CCNG System.

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Natural gas is supplied to the Gregory gathering system from approximately 100 wellhead receipt points by producers such as EOG, Sabco and Cabot. The Gregory system's connection to our CCNG system on October 1, 2011 provided greater supplies of natural gas to our Gregory processing plant.

We have secured additional sources of liquids-rich natural gas supplies that have increased the utilization of our processing capacity at our Gregory processing plant as a result of drilling activity in the Eagle Ford shale area. In order to take advantage of these additional sources, we have implemented a number of enhancements that will allow the Gregory processing plant to both process this new liquids-rich natural gas and improve NGL recoveries. These enhancements include installing inlet treating to process gas for higher CO_2 content, redesigning the expander / compressor, adding propane refrigeration, cryogenic pumps and adding residue recompression to improve ethane retentions and reactivating the second skid. As a result, we anticipate ethane retentions at the plant to increase from 56% to over 75% by September 1, 2012. We believe these enhancements will increase profitability and allow us to be more competitive in securing future gas supplies.

Produced NGLs are fractionated in our fractionator located on the same site as our Gregory processing plant. Purity ethane is shipped via pipeline to Dow Chemical while remaining NGLs are shipped via truck to local markets, which generally yield a premium to available pipeline rates. The Gregory fractionation plant has a total capacity of 4,800 Bbls/d and NGLs produced in excess of this capacity are expected to be shipped as y-grade to our new Bonnie View fractionation plant or to available y-grade pipeline markets.

All of our customers on the Gregory gathering system pay a flat fee for natural gas to be gathered in the system and processed at the Gregory processing plant. Most of these contracts also provide us with incremental revenues above the fixed fees to the extent we are able to recover higher-than-negotiated amounts of ethane through processing the natural gas. Our major customers on the Gregory gathering system and at the Gregory processing plant include Cabot Oil & Gas and Swift, which comprised 7% and 21%, respectively, of this system's gas volumes in 2011.

Conroe System and Processing Plant. Our Conroe processing plant is a 50 MMcf/d cryogenic natural gas plant currently limited to 24 MMcf/d capacity due to inlet compression constraints. The plant typically recovers approximately 65% of the ethane contained in the inlet natural gas, depending on loads and temperatures. We have a fixed-fee processing contract with Denbury Resources, under which approximately 70% of the residue gas from the Conroe plant is returned to them for gas lift purposes. We sell the remaining natural gas and NGLs to unaffiliated parties. Average throughput for the plant in 2011 was approximately 22 MMcf/d.

Mississippi and Alabama

Mississippi

In August 2009, we acquired approximately 626 miles of pipeline and 2,200 horsepower of compression in Mississippi from Crosstex. 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 currently consist of approximately 626 miles of pipeline ranging in diameter from 2" to 20" with an estimated design capacity of 345 MMcf/d. The Mississippi system also includes two compressors with total compression of approximately 2,200 horsepower. Our system throughput volumes in Mississippi are affected by both on-system gas production volumes and customers' demand for gas. Production volumes are strongly influenced by drilling levels, which are largely influenced by natural gas price levels. Because we supplement on-system production volumes with off-system supply from interstate pipelines, the level of throughput is not completely governed by production levels. Also, demand and throughput volumes can be volatile on the system due to occasional high-volume sales of natural gas we purchase and sell to off-system markets. In 2011, the system had an average throughput of 86 MMcf/d. The system has the capability to receive natural gas from three unaffiliated interstate

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pipelines Southeast Supply Header, Southern National (SONAT) and Texas Eastern to supplement supply on the system or to market gas off of the system.

We generate revenues from our Mississippi assets by charging fixed transportation fees to shippers and by entering into fixed-spread contracts with suppliers and power generation, industrial and utility customers. In 2011, fixed-fee transportation contracts comprised 34.8% of the volumes we transported on our Mississippi system and fixed-spread contracts comprised the remaining 65.2% of our volumes. Our major producer customers are Denbury Resources and Penn Virginia. Our largest customers on our Mississippi system are SMEPA and CF Industries. These customers accounted for 30.3% and 21.9% of our revenues on our Mississippi system for 2011.

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Alabama

In August 2009, we acquired approximately 125 miles of pipeline and 2,992 horsepower of compression in Alabama from Crosstex. The assets in our Alabama region are located in northwest and central Alabama and, following the EAI acquisition, which consisted of 388 miles of pipeline and 21,545 horsepower of compression, consist of 519 miles of natural gas gathering pipeline ranging from 2" to 16" in diameter. The Alabama system also includes 22 compressors with total compression of approximately 24,537 horsepower. The system has an estimated design capacity of 375 MMcf/d. The primary gas supply to the system is coalbed methane gas from the Black Warrior Basin with incremental volumes gathered from conventional gas wells. We gather, transport, compress, purchase and sell natural gas in Alabama and offer both intrastate transportation and interstate transportation services under NGPA Section 311. Through a combination of purchase, transportation, and sales arrangements, the throughput on our Alabama system, including the full year effect of the EAI acquisition, averaged approximately 120 MMcf/d in 2011 of which sales volumes constituted approximately 21 MMcf/d. For 2011, 81% of the volumes on our Alabama system were transported pursuant to fixed-fee transportation contracts and 19% of the volumes on the system were purchased from producers and then transported and sold to power generation, industrial and utility customers pursuant to fixed-spread contracts. Major counterparty customers include Entergy, BP Energy, Interconn Resources, Saga and Lamar County Gas District.

Competition

The natural gas gathering, compression, processing, transportation and marketing business and the NGL fractionation business are very competitive. Our competitors include other midstream companies, producers and intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, reliability, service levels, flexibility, access to markets, location, available capacity, capital expenditures and fuel efficiencies. Our principal competitors in South Texas are Copano Energy, L.L.C., Energy Transfer Partners, L.P., Enterprise Products Partners LP and Kinder Morgan Energy Partners LP. Our principal competitors in Alabama and Mississippi are Torch Energy Corporation, Gulf South Pipeline Company, LP, Southeast Supply Header, LLC, Samson Resources Inc. and El Paso Corporation.

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

Safety and Maintenance

We are subject to regulation by the PHMSA pursuant to the Natural Gas Pipeline Safety Act of 1968, or the NGPSA, and the Pipeline Safety Improvement Act of 2002, or 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. oil and natural gas transmission pipelines in high-consequence areas. The 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. Recently enacted pipeline safety legislation, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The PHMSA recently issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. We believe that this rule change does not affect our current pipelines. Future liquid pipeline expansions may be subject to this rule, but we do not believe compliance with the rule will have a material effect on our operations. 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 through more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. Additionally, 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 are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by 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.

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In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or 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. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization 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. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling points without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

We and the entities in which we own an interest are also subject to:

- 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;

- OSHA Process Safety Management Regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive materials; and

- Department of Homeland Security Chemical Facility Anti-Terrorism Standards, which are designed to regulate the security of high-risk chemical facilities.

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 Commission approval.

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. and Southcross Alabama Pipeline LLC, also provide interstate transportation service. The rates, terms and conditions of such services are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA, and Part 284 of the FERC's regulations. Pipelines providing transportation service under Section 311 are required to provide services on an open and nondiscriminatory basis. The

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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 an 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 the FERC are maximum rates and we may negotiate at or below such rates. Currently, the FERC reviews our maximum rates every five years and such maximum rates may increase or decrease as a result of such reviews. The terms and conditions of service set forth in the intrastate facility's statement of operating conditions are also subject to the FERC's review and approval. Should the FERC determine not to authorize rates equal to or greater than our currently approved Section 311 rates, 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 the FERC for Section 311 service, and 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. However, unlike intrastate pipelines, Hinshaw pipelines can receive gas from outside their state without becoming subject to FERC's NGA jurisdiction. Specifically, Section 1(c) of the NGA exempts from the 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 consumed within that state and (3) the pipeline is regulated by a state commission. Following the enactment of the NGPA, the 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 the FERC's regulations.

Historically, the FERC did not require intrastate and Hinshaw pipelines to meet the same rigorous transactional reporting guidelines as interstate pipelines. However, as discussed below, in 2010 the FERC issued a new rule, Order No. 735, which increases FERC regulation of certain intrastate and Hinshaw pipelines. See " Market Behavior Rules; Posting and Reporting Requirements."

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. We believe that our natural gas pipelines meet the traditional tests that the 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 the 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 the 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, the 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 has been no adverse effect to our system due to these regulations.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, or the EPAct 2005. Among other matters, the EPAct 2005 amended the NGA to add an anti-manipulation provision that makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by the FERC and, furthermore, provides the FERC with additional civil penalty authority. On January 19, 2006, the FERC issued Order No. 670, a rule implementing the anti-manipulation provision of the EPAct 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC or the purchase or sale of transportation services subject to the jurisdiction of the FERC to (1) use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a "nexus" to jurisdictional transactions. The EPAct 2005 also amends the NGA and the NGPA to give the FERC authority to impose civil penalties for violations of these statutes, up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, the FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines.

The EPAct of 2005 also added a Section 23 to the NGA authorizing the FERC to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. In 2007, the FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of annual quantities of natural gas of 2,200,000 MMBtu or more, including entities not otherwise subject to the FERC's jurisdiction, to provide by May 1 of each year an annual report to the FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting. In June 2010, the FERC issued the last of its three orders on rehearing and clarification further clarifying its requirements.

In 2008, the FERC issued Order No. 720 which increases the Internet posting obligations of interstate pipelines, and also requires "major non-interstate" pipelines (defined as pipelines that are not natural gas companies under the NGA that deliver more than 50 million MMBtu annually) to post on the Internet the daily volumes scheduled for each receipt and delivery point on their systems with a design capacity of 15,000 MMBtu/d or greater. Southcross CCNG Transmission Ltd. is currently subject to the posting requirement. Numerous parties requested modification or reconsideration of this rule. An order on rehearing, Order No. 720-A, was issued on January 21, 2010. In that order the FERC reaffirmed its holding that it has jurisdiction over major non-interstate pipelines for the purpose of requiring public disclosure of information to enhance market transparency. Order No. 720-A also granted clarification regarding application of the rule. Two parties have filed appeals of Order Nos. 720 and 720-A to the Fifth Circuit. On October 24, 2011, the Fifth Circuit issued its decision in Texas Pipeline Association v. Federal Energy Regulatory Commission, in which it vacated FERC Order Nos. 720 and 720-A on the basis that FERC did not have statutory authority under the NGA to require intrastate pipelines to disclose and disseminate capacity and scheduling information. FERC did not seek rehearing of the decision by the Fifth Circuit or review by the Supreme Court, and it is not known whether FERC intends to apply Order No. 720 to jurisdictions not within the jurisdiction of the Fifth Circuit. As a result of the Fifth Circuit's decision, some or all of our intrastate operations that otherwise would have been required to comply with Order No. 720's posting requirements will not be required to do so.

In May 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on the FERC's website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission's periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 became effective on April 1, 2011. In December 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring Section 311 and "Hinshaw" pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. In June 2011, the Commission extended the time for filing form 549D, the subject of Order No. 735, for the first quarter of 2011 until September 9, 2011, and for the second quarter until September 30, 2011.

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In October 2010, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether and how parties that hold firm capacity on some intrastate pipelines can allow others to use their capacity, including to what extent buy/sell transactions should be permitted and whether the FERC should consider requiring such pipelines to offer capacity release programs. In the Notice of Inquiry, the FERC granted a blanket waiver regarding such transactions while the FERC is considering these policy issues. The comment period has ended but the FERC has not yet issued an order.

Sales of Natural Gas and NGLs

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the NGA, the NGPA and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. 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 not currently 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 the FERC and/or the CFTC and the Federal Trade Commission, or FTC. 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 not currently regulated and are made at negotiated prices. Nevertheless, 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. The 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.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for the gathering, compressing, treating and transporting of natural gas and other products and the fractionation of NGLs 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 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;
- 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 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.

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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 waste products 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, compress, treat and transport natural gas. We cannot assure you, however, that future events, such as changes in existing laws 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. We believe that we are in substantial compliance with all of these environmental laws and regulations.

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 and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, referred to as 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 clean up 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, referred to as 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 these wastes, 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 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 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, and our Predecessor has in the past owned or leased, 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, or 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, or 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 United States. 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, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Air Emissions

Our operations are subject to the federal Clean Air Act, or 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 believe that we are in substantial compliance with these requirements. We 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, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

On August 20, 2010, the EPA published new regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocating internal combustion engines. On May 22, 2012, the EPA proposed amendments to the final rule in response to several petitions for reconsideration. The EPA must finalize the proposed amendments by December 14, 2012. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment, such as oxidation catalysts or non-selective catalytic reduction equipment, on all our engines following prescribed maintenance practices for engines (which are consistent with our existing practices), and implementing additional emissions testing and monitoring. Compliance with the final rule currently is required by October 2013. We are continuing our evaluation of the cost impacts of the final rule and proposed amendments.

On June 28, 2011, the EPA issued a final rule, effective August 29, 2011 modifying existing regulations under the CAA that established new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The final rule may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment. Compliance with the final rule is not required until at least 2013. On May 22, 2012, the EPA proposed minor amendments that must be finalized by December 14, 2012. We are currently evaluating the impact that this final rule and proposed amendments will have on our operations.

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 new rule addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. For new or reworked hydraulically-fractured 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 establishes specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. This rule may require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

Water Discharges

The Federal Water Pollution Control Act, or 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 United States and impose requirements affecting our ability to conduct construction activities in waters and wetlands. 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. 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 financial condition, results of operations or cash flow.

Safe Drinking Water Act

The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus

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and to prevent migration of fluids from the injection zone into underground sources of drinking water. We believe that our facilities will not be materially adversely affected by such requirements.

Endangered Species

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. 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.

National Environmental Policy Act

The National Environmental Policy Act, or NEPA, establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC approval must undergo NEPA review. Many of our activities are covered under categorical exclusions which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews and on March 12, 2012 issued final guidance that may result in longer review processes that could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Climate Change

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to the scientific studies, international negotiations to address climate change have occurred. The United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," became effective on February 16, 2005 as a result of these negotiations, but the United States did not ratify the Kyoto Protocol. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17 percent by 2020 compared to 2005 levels. We continue to monitor the international efforts to address climate change. Their effect on our operations cannot be determined with any certainty at this time.

In the United States, legislative and regulatory initiatives are underway to limit GHG emissions. The U.S. Congress has considered legislation that would control GHG emissions through a "cap and trade" program and several states have already implemented programs to reduce GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal CAA definition of an "air pollutant," and in response the EPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. In 2010, the EPA issued a final rule, known as the "Tailoring Rule," that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act.

In addition, on September 2009, the EPA issued a final rule requiring the reporting of GHGs from specified large GHG emission sources in the United States beginning in 2011 for emissions in 2010. Our Gregory and Conroe processing facilities are currently required to report under this rule. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting to include onshore and offshore oil and natural gas systems beginning in 2012. Several of our onshore compression facilities will likely be required to report under this rule, with the first report due to the EPA in 2012.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Moreover, while the U.S. Supreme Court held in its June 2011 decision in *American Electric Power Co., Inc. v. Connecticut* that with respect to claims concerning GHG emissions, the federal common law of nuisance was displaced by the federal Clean Air Act, the Court left open the question whether tort claims against GHG emissions sources alleging property damage may proceed under state common law. There thus remains some litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

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

The majority of scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous. 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.

Anti-terrorism Measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, or 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 establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be 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, recordkeeping, and protection of chemical-terrorism vulnerability information. Two of our facilities (the Gregory and Conroe 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 made the determination that none of the facilities are considered high-risk chemical facilities.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee 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

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facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. Our Predecessors leased or owned these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership in such lands. We have no knowledge 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.

Employees

We do not have any employees. The officers of our general partner will manage our operations and activities. As of December 31. 2011, Southcross Energy LLC retained 131 people who provide direct, full-time support to our operations. Subsequent to the closing of this offering, all of the employees required to conduct and support our operations will be employed by our general partner. None of these employees are covered by collective bargaining agreements, and our general partner considers its employee relations to be good.

Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business.

MANAGEMENT

Management of Southcross Energy Partners, L.P.

We are managed by the directors and executive officers of our general partner, Southcross Energy Partners GP, LLC. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. Holdings owns all of the membership interests in our general partner. Our general partner has a board of directors, and our unitholders are not entitled to elect the directors or directly or indirectly to participate in our management or operations. Our general partner will be liable, as 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 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 will have an audit committee, or the Audit Committee, a conflicts committee, or the Conflicts Committee, and a compensation committee, or the Compensation Committee, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Conflicts Committee

We will have a Conflicts Committee of one or more members of our board of directors. Jerry W. Pinkerton will serve as the initial member and chair of the Conflicts Committee, and one or more members will be appointed after the closing of this offering. Our partnership agreement provides for the Conflicts Committee, as delegated by the board of directors of our general partner as circumstances warrant, to 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, which will consist solely of independent directors, for their 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 members of the Conflicts Committee may not be executive officers or employees of our general partner or directors, executive officers or employees of its affiliates. In addition, the members of the Conflicts Committee must meet the independence and experience 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

Jerry W. Pinkerton, Jon M. Biotti and Samuel P. Bartlett will serve as the initial members of the Audit Committee, and Mr. Pinkerton will serve as the chair. The Audit Committee will oversee, review, act on and report on various auditing and accounting matters to the board of directors of our general partner, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the Audit Committee will oversee our compliance programs relating to legal and regulatory requirements. Our general partner will rely on the phase-in rules of the SEC and the NYSE with respect to the independence of the Audit Committee. Those rules permit our general partner to have an Audit Committee that has one independent member upon the effectiveness of the registration statement of which this prospectus forms a part, a majority of independent members within 90 days thereafter and all independent members within one year thereafter. In compliance with those rules, Mr. Bartlett will resign from the Audit Committee upon appointment of the first such additional independent director to the board of directors and the Audit Committee. Mr. Biotti will resign from the Audit Committee when the final independent director is appointed. Thereafter, our general partner is generally required to have at least three independent directors serving on its board at all times.

Compensation Committee

Kim G. Davis, Jon M. Biotti and Jerry W. Pinkerton will serve as the members of the Compensation Committee. Mr. Davis will serve as the chair of the Compensation Committee. The Compensation Committee will establish salaries, incentives and other forms of compensation for officers and other employees. The Compensation Committee will also administer 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. The following table shows information for the directors and executive officers of our general partner.

Name	Age	Position with Southcross Energy Partners GP, LLC
David W. Biegler	65	Chairman of the Board and Chief Executive Officer
Michael T. Hunter	62	President
J. Michael Anderson	50	Senior Vice President and Chief Financial Officer
David M. Mueller	54	Senior Vice President, Chief Accounting Officer
Albert B. Glasgow	61	Senior Vice President, Operations
Ronald J. Barcroft	68	Senior Vice President, Business Development
Samuel P. Bartlett	39	Director
Jon M. Biotti	43	Director
Kim G. Davis	58	Director
Jerry W. Pinkerton	71	Director

David W. Biegler

David W. Biegler was elected Chairman of the board of directors and Chief Executive Officer of our general partner in August 2011. Since July 2009, Mr. Biegler served as chairman of the board of directors and chief executive officer of Southcross Energy LLC, our predecessor. Mr. Biegler has 45 years of experience in the energy industry, having held various management positions in upstream, midstream, downstream 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 the 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. Mr. Biegler 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, he served as president and chief operating officer of TXU Corp., the result of a merger between Texas Utilities and ENSERCH Corporation. From 1966 to 1997, Mr. Biegler held various management positions at ENSERCH Corporation 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 serves as a director of Southwest Airlines Co. and Trinity Industries, Inc. He previously served as a director of Dynegy, Inc., Guaranty Financial Group, and Animal Health International, Inc. Mr. Biegler received a Bachelor of Science degree in physics from St. Mary's University and is a graduate of Harvard University's advanced management program. He has served as a member of the National Petroleum Council and as the chairman of the American Gas Association, the Southern Gas Association, the American Gas Foundation and the Texas Pipeline Association.

Michael T. Hunter

Michael T. Hunter was appointed President of our general partner in August 2011. Since July 2009, Mr. Hunter served as president and a member of the board of directors of Southcross Energy LLC, our predecessor. Mr. Hunter has 36 years of experience in the energy industry, having held various management and board positions in several energy companies. From 2004 until 2012, Mr. Hunter served as president of Estrella Energy LP, an entity formed for the purpose of acquiring midstream companies, which was a founding investor in our predecessor. From 2001 to 2004, Mr. Hunter was a member of the board of directors of Regency Gas Services, a midstream company that he co-founded and that was ultimately sold to a private equity firm. In 2000, Mr. Hunter retired as president of TXU Corp.'s (now Energy Future Holdings Corp.) pipeline business unit, the largest U.S. intrastate natural gas pipeline operation. Mr. Hunter held this position since TXU Corp. was formed as a result of the merger between Texas Utilities and ENSERCH Corporation in August 1997. Prior to the merger, Mr. Hunter served as the president of Lone Star Pipeline Company, a subsidiary of ENSERCH Corporation, from 1995 to 1997, and as the vice chairman of ENSERCH Processing, a subsidiary of ENSERCH Corporation from 1995 to 1997. From 1985 to 1995, Mr. Hunter was employed by NORAM Energy Corp. (f/k/a Arkla, Inc.) holding executive positions, including serving as President and Chief Operating Officer of its interstate natural gas pipeline entities.

Mr. Hunter serves as the vice chairman of the Texas Energy Reliability Council and has served as a member of the board of directors or as a trustee for the Southern Gas Association, Texas Pipeline Association, Gas Research Institute and Institute of Gas Technology. He is also a member of the board of directors for the University of Idaho Foundation. Mr. Hunter received a Bachelor of Science degree in political science and a Master's degree in business administration from the University of Idaho.

J. Michael Anderson

J. Michael Anderson was appointed Senior Vice President and Chief Financial Officer of our general partner in April 2012. Mr. Anderson was the Senior Vice President and Chief Financial Officer of Exterran GP LLC, the general partner of Exterran Partners, L.P., from November 2011 until he joined our general partner. Prior to that, Mr. Anderson had served as Senior Vice President of Exterran GP LLC since June 2006 and as a director of Exterran GP LLC since October 2006. He also served as Senior Vice President and Chief Financial Officer of Exterran Holdings, Inc. from August 2007 to December 2011. Prior to the merger of Hanover Compressor Company and Universal Compression Holdings Inc. in August 2007, Mr. Anderson was Senior Vice President and Chief Financial Officer of Universal, a position he assumed in March 2003. From 1999 to 2003, Mr. Anderson held various positions with Azurix Corp. (a water and wastewater utility and services company), primarily as the company's Chief Financial Officer and later as Chairman and Chief Executive Officer. Prior to that time, he spent ten years in the Global Investment Banking Group of J.P. Morgan Chase & Co. (a financial services company), where he specialized in merger and acquisitions advisory services. Mr. Anderson holds a BBA in finance from Texas Tech University and an MBA in finance from The Wharton School of the University of Pennsylvania.

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David M. Mueller

David M. Mueller was appointed Senior Vice President and Chief Accounting Officer of our general partner in April 2012. From August 2011 to April 2012, Mr. Mueller served as Senior Vice President, Finance and Administration of our general partner. Since July 2009, Mr. Mueller served as Senior Vice President, Finance and Administration of Southcross Energy LLC, our predecessor. Mr. Mueller has 33 years of financial and operational experience in the energy industry. Prior to joining Southcross Energy LLC, Mr. Mueller served as vice president, finance and controller of PSEG Texas (f/k/a Texas Independent Energy), an independent power producer and subsidiary of Public Service Enterprise Group Incorporated, from July 1999 to December 2008. From December 2008 until joining Southcross Energy LLC in July 2009, Mr. Mueller consulted for PSEG Texas, assisting in the management and orderly retirement of the company's long-term debt. From May 1984 to July 1999, Mr. Mueller served in various accounting and operational leadership roles at ENSERCH Corporation. From July 1979 to May 1984, Mr. Mueller worked for Deloitte & Touche LLP, providing auditing services to clients in the oil and natural gas exploration and production and electricity utility sectors. Mr. Mueller received a Bachelor of Science degree in business administration from Texas Tech University. He is a member of the American Institute of Certified Public Accountants and Financial Executives International.

Albert B. Glasgow

Albert B. Glasgow was appointed Senior Vice President, Operations of our general partner in August 2011. Since 2009, Mr. Glasgow served as Senior Vice President, Operations of Southcross Energy LLC, our predecessor. Mr. Glasgow has 38 years of experience in the energy industry. Prior to joining Southcross Energy LLC, he served as vice president of operations for the western division of Duke Energy Field Services, LLC, a joint venture between Phillips Petroleum (now ConocoPhillips Company) and Duke Energy Corporation from April 2000 to March 2005. Prior to that, Mr. Glasgow served as the operations manager for the Oklahoma region of GPM, a strategic business unit of Phillips Petroleum. Mr. Glasgow received a Bachelor of Mechanical Engineering degree from Texas A&M University in 1973 and is a registered professional engineer in the states of Oklahoma and Texas. Mr. Glasgow is active in the Gas Processors Association, having served as a regional program committee member, Permian Basin Chapter President for three terms, and co-chairman of the maintenance and operations section for the national organization.

Ronald J. Barcroft

Ronald J. Barcroft was appointed Senior Vice President, Business Development of our general partner in August 2011. Since July 2009, Mr. Barcroft served as Senior Vice President, Commercial of Southcross Energy LLC, our predecessor. Mr. Barcroft has 43 years of experience in the energy industry in the United States and Canada. From 2005 until 2012, Mr. Barcroft served as Senior Vice President of Estrella Energy LP, an entity formed for the purpose of acquiring midstream companies, which was a founding investor in our predecessor. In 2005, he retired as vice president of Duke Energy Field Services, LLC, where he was responsible for the Western Division's commercial and business development activities. From 1989 to 1991, Mr. Barcroft served in various management positions at Associated Natural Gas, Inc. (the predecessor to Duke Energy Field Services, LLC), including commercial vice president, from 1991 to 2005, a position he held during various mergers and acquisitions that made Duke Energy Field Services, LLC the largest midstream company in the United States. From 1986 to 1989, Mr. Barcroft worked at Midstates Natural Gas, a startup gas gathering and processing company in Oklahoma, after selling Valley Energy, a Colorado gathering, processing and marketing company he founded in 1983, to Associated Natural Gas Inc. From 1969 to 1983, Mr. Barcroft held various engineering and management positions with Shell Canada, Air Liquide Engineering & Construction and Dome Petroleum in the United States and Canada.

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Mr. Barcroft received a Bachelor's of Applied Science in chemical engineering in 1969 from the University of Waterloo, Ontario. Prior to leaving Canada, Mr. Barcroft was a registered engineer in Quebec and Alberta. He has served on the board of the Gas Processors Association, Oklahoma region, and on various Gas Processors Association regional committees.

Samuel P. Bartlett

Mr. Bartlett has served as a director of our general partner since April 2012 and was appointed to the board in connection with his affiliation with Charlesbank, which controls our general partner. Mr. Bartlett is a Managing Director of Charlesbank, a private investment firm located in Boston, Massachusetts, with an office in New York. Prior to joining Charlesbank in 1999, he was employed by Bain & Company, where he worked in the private equity and general practice areas. Mr. Bartlett serves as a director of CIFC Corp. In addition, Mr. Bartlett serves on the board of directors of a privately held Charlesbank portfolio company. Mr. Bartlett received a BA, *magna cum laude,* from Amherst College. Mr. Bartlett was selected to serve as a director on the board due to his affiliation with Charlesbank, his knowledge of the energy industry and his financial and business expertise.

Jon M. Biotti

Mr. Biotti has served as a director of our general partner since April 2012 and was appointed to the board in connection with his affiliation with Charlesbank, which controls our general partner. Mr. Biotti is a Managing Director of Charlesbank, which he joined in 1998. Mr. Biotti serves as a director of Blueknight Energy Partners G.P., L.L.C., the general partner of Blueknight Energy Partners, L.P., a publicly traded master limited partnership that provides integrated terminalling, storage, processing, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and asphalt products. Mr. Biotti serves on the board of directors of several privately held Charlesbank portfolio companies. Mr. Biotti was also a board member of Regency Gas Services, representing Charlesbank which was Regency's founding equity investor. Educated at Harvard, Mr. Biotti received a Bachelor's degree in government and sociology, an MBA and an MA in public administration. Mr. Biotti was selected to serve as a director on the board due to his affiliation with Charlesbank, his knowledge of the energy industry and his financial and business expertise.

Kim G. Davis

Mr. Davis has served as a director of our general partner since April 2012 and was appointed to the board in connection with his affiliation with Charlesbank, which controls our general partner. Mr. Davis is a Managing Director and founding partner of Charlesbank. Prior to co-founding Charlesbank in July 1998, he was a Managing Director of its predecessor firm, Harvard Private Capital Group. Previously, Mr. Davis was at Kohlberg & Co. as General Partner, at Weiss, Peck & Greer as Partner, and at General Motors and Dyson-Kissner-Moran in various positions. Mr. Davis serves on the board of directors of several privately held Charlesbank portfolio companies. Mr. Davis was also a board member of Regency Gas Services, representing Charlesbank which was Regency's founding equity investor. He graduated from Harvard University with a BA in history and also holds an MBA from Harvard. Mr. Davis was selected to serve as a director on the board due to his affiliation with Charlesbank, his knowledge of the energy industry and his financial and business expertise.

Jerry W. Pinkerton

Jerry W. Pinkerton was appointed as a member of the board of directors of our general partner in April 2012. In addition, Mr. Pinkerton serves as Chairman of the audit committee of our general partner. With respect to the audit committee, Mr. Pinkerton qualifies as an "audit committee financial expert." Mr. Pinkerton has over 49 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

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directors and as chairman of the audit committee of Holly Energy Partners, L.P. since July 2004. From December 2000 to December 2003, Mr. Pinkerton served as a consultant to TXU Corp. (now Energy Future Holdings Corp.), 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., where he also served as chairman of its audit committee.

The members of our general partner appointed Mr. Pinkerton 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 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. Mr. Pinkerton received his Bachelor of Business Administration degree in Accounting from The University of North Texas.

Executive Compensation

We do not directly employ any of the persons responsible for managing our business. Our general partner, under the direction of its board of directors, or the Board, is responsible for managing our operations and employs all of the employees that operate our business. The compensation payable to the officers of our general partner is paid by our general partner and such payments are reimbursed by us on a dollar-for-dollar basis. See "The Partnership Agreement Reimbursement of Expenses."

Overview

This Executive Compensation disclosure describes the material components of our executive compensation program for our named executive officers, or NEOs. For the year ended December 31, 2011, our NEOs are:

- David W. Biegler, Chief Executive Officer
- Michael T. Hunter, President
- Ronald J. Barcroft, Senior Vice President, Business Development

In early 2012, we hired J. Michael Anderson to serve as our Chief Financial Officer, effective as of April 2, 2012. Although Mr. Anderson was not one of our NEOs during the year ended December 31, 2011, we expect that he will be an NEO during our fiscal year 2012 and, accordingly, have included his current compensation information in this disclosure as applicable.

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Elements of the Compensation Program. Compensation for our NEOs consists primarily of the elements, and their corresponding objectives, identified in the following table.

Compensation Element	Characteristics	Primary Objective
Base salary	Fixed annual cash compensation. Salaries may be increased periodically based on performance or other factors.	Recognize performance of job responsibilities and attract and retain individuals with superior talent.
Annual performance-based compensation	Performance-related annual cash incentives earned based on financial and operational objectives.	Promote near-term performance objectives and reward individual contributions to the achievement of those objectives.
Long-term equity participation	In 2009, our NEOs were given the opportunity to purchase units of Holdings at a price equal to that offered to Charlesbank. A portion of the units in Holdings purchased by our NEOs in 2009 were subject to time and performance based vesting restrictions and intended to contain long-term incentives as the NEO must remain an employee in order for the units to vest. Unvested units are subject to repurchase by Holdings upon certain terminations of employment at their original acquisition cost (or less in certain circumstances).	Emphasize long-term performance objectives, encourage the maximization of unitholder value and retain key executives by providing an opportunity to participate in the ownership of our partnership. Vesting restrictions are designed to facilitate NEO retention and to provide continuing performance incentives.
Severance and change in control benefits	Severance agreements provide for six or twelve months of base salary and benefit continuation in the event of certain involuntary terminations of employment. A portion of the NEOs' equity incentives are subject to accelerated change in control vesting.	Encourage the continued attention and dedication of key individuals and focus the attention of key individuals when considering strategic alternatives.
Retirement savings (401(k)) plan	Qualified 401(k) retirement plan benefits are available for our executive officers and all other regular full-time employees. For 2011, we matched employee contributions to 401(k) plan accounts up to a maximum employer contribution of 6% of the employee's eligible compensation.	Provide an opportunity for tax-efficient savings.
Health and Welfare Benefits	Health and welfare benefits (medical, dental, vision, disability insurance and life insurance) are available for our executive officers and all other regular full-time employees.	Provide benefits to meet the health and wellness needs of our executive officers and other employees and their families.

Base Salary. We believe that executive officer base salaries should be competitive with salaries for executive officers in similar positions with similar responsibilities in our marketplace. Base salaries for our NEOs were initially set at modest levels, primarily due to our limited operating history at the time such salaries were determined and in order to limit fixed administrative costs during our initial period of operations, with the expectation that base salaries would be increased over time to bring them closer to competitive levels of base salaries in our industry as the complexity and scope of our business increased. Effective March 2011, Messrs. Biegler, Hunter and Barcroft each received base salary increases of approximately 35.0%, 7.7% and 7.1%, respectively, in order to more closely align their base salaries with competitive base salaries in our industry and in recognition of the increased scope of their responsibilities as a result of the growth of our business. In addition, effective March 2012, Messrs. Biegler, Hunter and Barcroft each received base salary increases of approximately 60%, 7.1% and 4.0%, respectively, which increases were made to reflect the increased scope of these NEO's respective positions as our company continues to grow and mature and, with respect to Mr. Biegler, to reflect an increase from 60% to 100% with respect to the amount of time he devotes to our company. Mr. Anderson's base salary was established pursuant to negotiations with Mr. Anderson during his hiring process in early 2012.

The current base salaries for our NEOs and for Mr. Anderson are set forth in the following table:

Name and Principal Position	Base Salary ($)
David W. Biegler Chief Executive Officer	400,000
Michael T. Hunter President	300,000
Ronald J. Barcroft Senior Vice President, Business Development	234,000
J. Michael Anderson Chief Financial Officer	275,000

Going forward, base salaries for our NEOs will continue to be reviewed periodically by the Compensation Committee, with adjustments expected to be made generally in accordance with the considerations described above and to maintain base salaries at competitive levels.

Annual Performance-Based Compensation For 2011. Each of our NEOs participates in an annual incentive bonus compensation program under which incentive awards are determined annually, with target bonus levels historically having been set at 40% of base salary for Messrs. Biegler and Hunter, and 30% of base salary for Mr. Barcroft. Prior to 2011, annual incentive bonuses were determined based on the achievement of pre-established financial and operational performance criteria, including our level of achievement against a range of total EBITDA targets. In early 2011, due to the expected variability of income associated with our large expansion (including the construction of our new Woodsboro processing plant, the expansion of our Gregory plant and the construction of our McMullen pipeline extension), we determined not to establish EBITDA targets or other financial and operational performance criteria with respect to our 2011 annual incentive compensation program. Instead, we determined that 2011 annual incentive bonus awards for our NEOs would be determined by the board of managers of Southcross Energy LLC, or the Holdings Board, in its discretion following the completion of the 2011 fiscal year, based upon factors such as the satisfactory execution of the company's growth plans, including completion of new gas supply contracts, progress on the construction of our new Woodsboro processing plant, the expansion of our Gregory plant, the construction of our McMullen pipeline extension, and each individual's contributions to our overall success during the year. For 2011, although our overall financial performance was below expectations, the Holdings Board determined generally that the NEOs had successfully executed on our strategic growth plans described above and that, therefore, they would each receive a bonus equal to 60% of their target bonus amounts (40% of base salary for Messrs. Biegler and Hunter and 30% of base salary for Mr. Barcroft). The actual amounts awarded to each NEO are set forth below in the Summary Compensation Table.

Benefit Plans and Perquisites. We provide our executive officers, including our NEOs, 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, or 401(k) Plan. We believe that our health benefits provide stability to our NEOs, 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 2011, we provided an employer match under the 401(k) plan equal to 100% of employee contributions up to 6% of base salary. In 2011, none of our executive officers, including our NEOs, received any personal benefits or perquisites that were not made generally available to all of our salaried employees on a non-discriminatory basis. In addition, none of our NEO participated in any defined benefit pension plans or nonqualified deferred compensation plans.

Summary Compensation Table for 2011

The following table sets forth certain information with respect to the compensation paid to our NEOs for the year ended December 31, 2011.

Name and Principal Position	Annual Salary ($)	Bonus ($)(1)	All Other Compensation ($)(2)	Total ($)
David W. Biegler Chief Executive Officer	232,500	60,000		292,500
Michael T. Hunter President	275,385	67,200	14,700	357,285
Ronald J. Barcroft Senior Vice President, Business Development	221,539	40,500	14,700	276,739

(1) Represents the awards earned under our annual incentive bonus program for the year ended December 31, 2011. For a discussion of the determination of these amounts, see "Annual Performance-Based Compensation for 2011" above.

(2) Represents employer contributions under the 401(k) Plan.

Long-Term Equity Incentive Units. In August 2009, in connection with the formation of Holdings, each of our NEOs were allowed to purchase equity interests in Holdings, pursuant to subscription agreements entered into with Holdings. The purchase price paid for the units was the same price paid per unit by Charlesbank. A portion of the units purchased by our NEOs, which portion we refer to as the incentive units, are subject to vesting restrictions and were intended as equity incentives to promote long-term compensation objectives and provide our NEOs with meaningful incentives to increase unitholder value over time. Twenty-two percent (22%) of the incentive units are tied to time-based vesting requirements and seventy-eight percent (78%) are tied to performance-based vesting conditions. The units subject to time-based vesting requirements vest in five cumulative annual installments, twenty percent (20%) of the relevant units on each anniversary of the grant date, and are subject to the requirement of continued employment through the applicable vesting date. Generally, the time vesting incentive units are designed to compensate, motivate and retain the recipients by subjecting such equity ownership to continued service requirements.

The performance-based vesting incentive units are intended to motivate our NEOs and to reward the financial success of Holdings, which, following the consummation of this offering, will be tied directly to our financial success. The units held by our NEOs will vest, if at all, only upon the occurrence of a transaction that results in Charlesbank receiving cash or liquid securities in an amount that results in Charlesbank achieving certain investment multiples and internal rates of return with respect to its investment in Holdings. A portion of the performance-based vesting units vest upon the occurrence of such a transaction that results in Charlesbank achieving an investment multiple reflecting a return of 2.0 times invested capital and an internal rate of return of 20%, and the remainder of such units vest cumulatively based on the occurrence of a transaction that results in Charlesbank achieving investment multiples and internal rates of return over and above these threshold amounts. The units will be fully vested upon the occurrence of a transaction that results in Charlesbank achieving an investment multiple reflecting a return of 3.5 times invested capital and an internal rate of return of 35%. The performance-based vesting units are also subject to the requirement of continued employment through the applicable vesting date. The consummation of this offering will not constitute a liquidity event for purposes of the performance-based incentive units. Upon an NEO's termination of employment, any unvested incentive units are subject to repurchase rights by Holdings at the NEO's initial acquisition cost of the units (or less in certain circumstances). See "Severance and Change in Control Benefits" below for a description of the circumstances under which vesting of the incentive units may be accelerated.

Our NEOs did not receive any equity incentive units in 2011; however, in connection with his commencement of employment, Mr. Anderson received 15,000 equity equivalent units and corresponding distribution equivalent rights (DERs), as described in more detail below. Going forward, we expect to use equity-based incentives more regularly and that equity-based awards will become more prominent in our annual compensation decision-making process. In anticipation of our initial public offering, we intend to adopt a new long-term equity incentive plan, which we refer to as the "LTIP," and which is discussed in more detail under "2012 Long-Term Incentive Plan" below.

Mr. Anderson's Equity Equivalent Units. In connection with his commencement of employment, the Holdings Board determined to grant an equity incentive award to Mr. Anderson to provide him with meaningful incentives to increase unitholder value over time. However, due to our contemplated initial public offering and the Holdings Board's intent to provide Mr. Anderson with direct ownership incentives in us following the completion of this offering, the Holdings Board determined that Mr. Anderson would be granted equity equivalent units rather than actual common units in Holdings of the type held by our other NEOs. Mr. Anderson was granted 15,000 equity equivalent units, each of which is intended to be equivalent in value to one incentive unit of the type previously purchased by our NEOs. These units vest in three cumulative annual installments, one-third of the units on each anniversary of the grant date, subject to continued employment through the applicable vesting date. Upon Mr. Anderson's termination of employment without cause or generally upon a change in control of Holdings or us, any unvested units and DERs will vest in full. Generally, if any of Mr. Anderson's equity equivalent units vest prior to the consummation of this offering, he will be entitled to receive for each vested equity equivalent unit one incentive unit in Holdings. In connection with the consummation of this offering, Mr. Anderson's equity equivalent units will be converted, on an equivalent value basis, into restricted phantom equity equivalent units in us, as our general partner may determine prior to the effectiveness of the registration statement of which this prospectus is a part. Any such units in us will be granted under our LTIP, which is described in more detail below under "2012 Long-Term Incentive Plan."

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Outstanding Incentive Units at December 31, 2011

The following table provides information regarding the incentive units in Holdings held by the NEOs as of December 31, 2011. None of our NEOs held any options that were outstanding as of December 31, 2011.

	Incentive Units(1)			
Name	**Number of Time-Vesting Units That Have Not Vested (2)**	**Fair Value of Time-Vesting Units That Have Not Vested (4)**	**Number of Performance-Vesting Units That Have Not Vested (3)**	**Fair Value of Performance-Vesting Units That Have Not Vested (4)**
		(in thousands)		**(in thousands)**
David W. Biegler	7,303	$ 854.5	43,470	$ 5,086.0
Michael T. Hunter	7,303	854.5	43,470	5,086.0
Ronald Barcroft	2,578	301.6	15,343	1,795.1

(1) Prior to March 20, 2012, incentive units were held by the named executive officers indirectly through Estrella Energy, LP, which was partially owned by a non-management third party. Amounts presented in the table above do not include the incentive units held by Estrella Energy, LP and attributable to such non-management third party, which were repurchased by Holdings on March 20, 2012. The named executive officers did not receive any consideration in connection with such repurchases.

(2) Represents the number of unvested time vesting incentive units in Holdings purchased on August 6, 2009. The remaining unvested units vest in three equal annual installments on each of August 6, 2012, 2013 and 2014, subject to the recipient's continued employment through the applicable vesting date.

(3) Represents the number of unvested performance vesting incentive units in Holdings purchased on August 6, 2009. The units will vest, if at all, upon Charlesbank attaining certain investment multiples and internal rates of return in connection with a liquidity event with respect to its investment in Holdings, subject to the recipient's continued employment through the applicable vesting date. For additional information relating to the performance vesting incentive units, see the discussion above under "Long Term Equity Incentive Units".

(4) Amounts shown were calculated based on an estimate of the fair market value of units in Holdings on December 31, 2011.

Severance and Change in Control Benefits

Our NEOs are entitled to severance payments and benefits upon certain terminations of employment and, in certain cases, upon a change in control of Holdings. In addition, Mr. Anderson is entitled to severance payments and benefits upon certain qualifying terminations of employment (including in connection with a change in control).

Each of our NEOs has entered into a severance agreement with Holdings which provides for severance benefits upon certain terminations of employment. As described below, these agreements are substantially similar for each of the NEOs. In addition, pursuant to the severance agreements for our NEOs, described in more detail below, upon termination of an NEO's employment due to death or disability, the NEO is entitled to accelerated vesting of any unvested time vesting incentive units that would have become vested within one (1) year following the date of the NEO's death or disability, as applicable. Mr. Anderson, who has not entered into a severance agreement with Holdings, is party to an offer of employment letter with Holdings which provides for severance payments and benefits upon certain qualifying terminations of employment, as described below.

NEOs' Severance Benefits. Under the severance agreement of each NEO, upon termination of the NEO's employment by us without "cause" or by the NEO for "good reason" (provided that termination for "good reason" occurs no more than forty-five (45) days following the last event constituting "good reason"), the NEO is entitled to receive (i) twelve months of base salary continuation, and (ii) company-subsidized group health plan benefits for up to twelve months.

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Additionally, severance payments are conditioned upon the execution of a general release of claims and continued compliance with certain confidentiality, non-competition and non-solicitation restrictions for six months following termination.

"Cause" is defined in the NEOs' severance agreements to mean (i) the executive's indictment for or conviction of, or entering a plea of *nolo contendere*, to any crime (whether or not a felony) involving dishonesty, fraud, embezzlement, breach of trust or other crime of moral turpitude, (ii) the executive's conviction of, entering a plea of *nolo contendere* to, a felony (other than a traffic violation), (iii) acts by the executive constituting fraud or willful misconduct in connection with the executive's employment or service relationship, including misappropriation or embezzlement in the performance of the executive's duties, (iv) the executive's failure or willful refusal to perform any of the executive's duties (other than a failure resulting from incapacity due to physical or mental illness) which is reasonably likely to result in material harm to Holdings or its subsidiaries, provided that such failure or refusal is not cured within thirty days of receiving written notice from Holdings, (v) the executive's violation or breach of the ethics provisions of the employee handbook applicable to all employees generally, or the executive's duty of loyalty to Holdings or its affiliates, (vi) the executive willfully or grossly negligently engaging in conduct materially injurious to Holdings or any of its subsidiaries, or (vii) the executive's failure or refusal to devote all of the executive's "business time" to the business and affairs of Holdings and its subsidiaries, provided that such failure or refusal is not cured within thirty days of receiving written notice from Holdings. Generally, "business time" excludes time spent (a) serving on certain corporate, charitable or civic boards or committees, or (b) delivering lectures, fulfilling speaking engagements or teaching at educational institutions.

"Good reason" is defined in the NEOs' severance agreements to mean (i) an involuntary reduction in the annual base salary, other than a reduction to which the executive consents or that similarly affects all or substantially all management employees, (ii) a relocation, without the executive's prior written consent, of the geographic location of the executive's principal place of employment by more than twenty-five miles from the executive's principal place of employment as of August 6, 2009, or (iii) the failure of Holdings to pay any cash compensation (such as base salary or bonuses) to the executive when due under the terms of any employment agreement or bonus plan in which the executive is entitled to participate, provided that Holdings has not cured such failure within thirty days of receiving written notice from the executive.

NEOs' Change in Control Benefits. Our NEOs are not entitled to any cash payments upon a change in control of us or Holdings. However, pursuant to the subscription agreements relating to the NEO's incentive units, the NEOs' time vesting incentive units will vest in full upon a change in control of Holdings. In addition, upon the occurrence of a liquidity event with respect to Charlesbank's investment in Holdings, which event may also constitute a change in control, the NEOs' performance vesting incentive units may vest, depending upon the financial outcome of such transaction. For additional information regarding the vesting of the incentive units, see the discussion under "Long-Term Equity Incentive Units" above. The consummation of this offering will not constitute a change in control or liquidity event for purposes of our NEOs' incentive units.

Mr. Anderson's Severance and Change in Control Benefits. Under Mr. Anderson's offer of employment letter, upon a termination of his employment without cause or certain transactions generally resulting in a change in control of Holdings or us, any unvested equity equivalent units and DERs will vest in full and he will be entitled to receive a cash payment in respect of such units. If a termination of Mr. Anderson's employment without cause occurs within one year following certain transactions generally resulting in a change in control of Holdings or us, he will also be entitled to receive an amount equal to two times his annual base salary plus two times his target annual bonus, which is 60% of his base salary. For additional information regarding the vesting of the equity equivalent units, see the discussion under "Long-Term Equity Incentive Units" above. The

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consummation of this offering will not constitute a change in control or liquidity event for purposes of Mr. Anderson's equity equivalent units.

Potential Payments Upon Termination and/or a Change in Control. The following table summarizes the change in control and/or severance payments and benefits that each of our NEOs would have received upon a termination of employment effective as of December 31, 2011 (i) by Holdings without cause, (ii) due to the executive's resignation for good reason, or (iii) due to the executive's death or disability. The table also summarizes the value of the vesting acceleration of time vesting incentive units assuming a change in control or liquidity event occurring as of December 31, 2011 and the value of the vesting of performance vesting incentive units assuming a liquidity event occurring with respect to the units effective as of December 31, 2011 (based on the maximum potential amount of performance unit vesting), in each case, assuming a unit value as of such date of $117.00 and each NEO's base salary in effect as of such date.

Name	Payment Type	Termination Without Cause or Due to Resignation for Good Reason ($)	Termination Due to Death or Disability ($)	Change in Control/Liquidity Event (No Termination) ($)
David W. Biegler	Salary(1)	250,000		
	Benefit continuation	(3)		
	Value of Time Vesting Unit Acceleration		284,818	854,454
	Value of Performance Unit Vesting			5,086,039
	Total	250,000	284,818	5,940,464
Michael T. Hunter	Salary(1)	280,000		
	Benefit continuation(2)	16,248		
	Value of Time Vesting Unit Acceleration		284,818	854,454
	Value of Performance Unit Vesting			5,086,039
	Total	296,248	284,818	5,940,464
Ronald J. Barcroft	Salary(1)	225,000		
	Benefit continuation(2)	17,217		
	Value of Time Vesting Unit Acceleration		100,524	301,572
	Value of Performance Unit Vesting			1,795,072
	Total	242,217	100,524	2,096,645

(1) Represents the executive's annual base salary, payable over the one-year period following termination.

(2) Consists of continuation of group health benefits. The value of the health benefits was calculated using an estimate of the cost of such health coverage based upon current COBRA plan premium rates.

(3) Mr. Biegler did not participate in our group health benefit plans as of December 31, 2011.

Director Compensation

Officers, employees or paid consultants or advisors of us or our general partner who also serve as directors will not receive additional compensation for their service as directors. We anticipate that directors who are not officers, employees or paid consultants or advisors of us or our general partner will receive a combination of cash and common unit grants as compensation for attending meetings of the board of directors of our general partner and any committees thereof. Such directors will also receive reimbursement for out-of-pocket expenses associated with attending such board or committee meetings and director and officer liability insurance coverage. Each director will be fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

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2012 Long-Term Incentive Plan

Prior to the consummation of this offering, our general partner intends to adopt a 2012 Long-Term Incentive Plan, or LTIP, pursuant to which our, our subsidiaries' and our general partner's eligible officers (including the NEOs), employees and directors will be 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 anticipated material features of the LTIP. This summary, however, does not purport to be a complete description of all of the anticipated provisions of the LTIP. In addition, our general partner is still in the process of implementing the LTIP and, accordingly, this summary is subject to change prior to the effectiveness of the registration statement of which this prospectus is a part.

The LTIP will provide for the grant, from time to time at the discretion of the board of directors or compensation committee of our general partner, of restricted units, phantom units, unit options, distribution equivalent rights and other unit-based awards. Subject to adjustment in the event of certain transactions or changes in capitalization, an aggregate of common units may be delivered pursuant to awards under the LTIP. Units that are cancelled or forfeited will be available for delivery pursuant to other awards. We expect that the LTIP will be administered by our general partner's board of directors, though such administration function may be delegated to a committee (including the compensation committee) that may be appointed by the board to administer the LTIP. The LTIP will be designed to promote our interests, as well as the interests of our unitholders, by rewarding the officers, employees and directors of us, our subsidiaries and our general partner for delivering desired performance results, as well as by strengthening our and our general partner's ability to attract, retain and motivate qualified individuals to serve as directors, consultants and employees.

Restricted Units and Phantom Units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. 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 restricted and 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 restricted or 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 of control (as defined in the LTIP) or as otherwise described in an award agreement.

Distributions made by us with respect to awards of restricted units may be subject to the same vesting requirements as the restricted units. 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 equal to all or a portion of the cash distributions made on units during the period a phantom unit remains outstanding.

Unit Options. The LTIP may also permit the grant of options covering common units. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit options may be granted to such eligible individuals and with such terms as the administrator of the LTIP may determine, consistent with the LTIP; however, a unit option must have an exercise price equal to at least the fair market value of a common unit on the date of grant.

Other Unit-Based Awards. The LTIP may also permit the grant of "other unit-based awards," which are awards that, in whole or in part, are valued or based on or related to the value of a unit. The vesting of an other unit-based award may be based on a participant's continued service, the achievement of performance criteria or other measures. On vesting or on a deferred basis upon specified future dates or events, an other unit-based award may be paid in cash and/or in units (including restricted units), as the administrator of the LTIP may determine.

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 Long-Term Incentive Plan. 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 10th anniversary of the date it was initially adopted by our general partner. The administrator of the LTIP will also 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 materially impair the vested rights of the participant without the consent of the affected participant, and/or result in taxation to the participant under Section 409A of the Code.

Awards in Connection with this Offering. In connection with and shortly following the consummation of this offering, we expect that our general partner will grant awards under out LTIP to certain key employees, including some or all of our NEOs. We expect that such awards will be in the form of phantom units, however, the terms of such awards and the amounts to be granted to each award recipient have not yet been determined.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information regarding the beneficial ownership of units following the closing of this offering and the related transactions by:

- each person who is known to us to beneficially own 5% or more of such units to be outstanding;
- our general partner;
- 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.

Our general partner is owned 100.0% by Holdings. Charlesbank Equity Fund VI, Limited Partnership and its affiliated investment funds hold an aggregate 88.0% equity interest in Holdings, consisting of 85.2% of Holdings' outstanding Class A Common Units, 93.5% of Holdings' outstanding Series A Preferred Units, 95.1% of Holdings' outstanding Redeemable Preferred Units and 68.6% of Holdings' outstanding Series B Redeemable Preferred Units. In addition, members of management hold an aggregate 2.7% equity interest in Holdings, consisting of 10.6% of Holdings' outstanding, Class A Common Units, 2.0% of Holdings' outstanding Series A Preferred Units, 0.4% of Holdings' outstanding Redeemable Preferred Units, 2.3% of Holdings' outstanding Series B Redeemable Preferred Units and 100% of Holdings' Special Class B Units.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, 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, or "investment power," which includes the power to dispose of 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, common units subject to options or warrants held by that person that are currently exercisable or exercisable within 60 days of , 2012, if any, are deemed outstanding, but are not deemed 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 and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

The percentage of units beneficially owned is based on a total of common units and subordinated units outstanding immediately following this offering.

Name Of Beneficial Owner	Common Units to be Beneficially Owned(4)	Percentage of Common Units to be Beneficially Owned	Subordinated Units to be Beneficially Owned	Percentage of Subordinated Units to be Beneficially Owned	Percentage of Total Common and Subordinated Units to be Beneficially Owned
		%		%	%
Southcross Energy LLC(1)(2)		%		%	%
Charlesbank Equity Fund VI, Limited Partnership(3)(4)		%		%	%
Samuel P. Bartlett(3)		%		%	%
Jon M. Biotti(3)		%		%	%
Kim G. Davis(3)		%		%	%
David W. Biegler(1)		%		%	%
Michael T. Hunter(1)		%		%	%
Ronald J. Barcroft(1)		%		%	%
		%		%	%

All directors and executive officers as a group (consisting of persons)

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

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(1) The address for this person or entity is 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201.

(2) Southcross Energy LLC owns 100% of our general partner and, following this offering, will own % of our outstanding common units and % of our outstanding subordinated units. The following table sets forth the beneficial ownership of equity interests in Southcross Energy LLC.

Name of Beneficial Owner	Class A Common	Percentage of Class A Common Beneficially Owned	Class B Special Units	Percentage of Class B Special Units Beneficially Owned	Series A Preferred	Percentage of Series A Preferred Beneficially Owned	Redeemable Preferred Units	Percentage of Redeemable Preferred Units Beneficially Owned	Series B Redeemable Preferred Units	Percentage of Series B Redeemable Preferred Units Beneficially Owned
Charlesbank Equity Fund VI, Limited Partnership(a)	1,118,717	85.2%			11,075,303	93.5%	1,425,732	95.1%	2,420,625	68.6%
David W. Biegler(b)	54,857	4.2%	12,171	42.5%	112,732	1.0%			45,000	1.3%
Michael T. Hunter(b)	49,857	3.8%	12,171	42.5%	63,232	1.0%			32,534	1.0%
Ronald J. Barcroft(b)	16,749	1.3%	4,295	15.0%	13,931	*				
Albert B. Glasgow(b)	9,006	*			19,009	*	2,777	*		
David M. Mueller(b)	8,256	*			11,674	*	1,240	*		

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

(a) Charlesbank Equity Fund VI, Limited Partnership and its affiliated investment funds (the "Charlesbank Funds") are members of Southcross Energy LLC and may therefore be deemed to beneficially own the common units and subordinated units held by Southcross Energy LLC. The address for the Charlesbank Funds is 200 Clarendon Street, 54th Floor, Boston, MA 02116.

(b) The address for each individual is 1700 Pacific Avenue, Suite 2900, Dallas, Texas 75201.

(3) The Charlesbank Funds are members of Southcross Energy LLC and may therefore be deemed to beneficially own the common units and subordinated units held by Southcross Energy LLC. Samuel Bartlett, Jon Biotti and Kim Davis, each a director of our general partner, are managing directors of Charlesbank Capital Partners, LLC, the investment adviser to the Charlesbank Funds. They disclaim beneficial interest in our common and subordinated units except to their pecuniary interest therein.

(4) The address for this person or entity is 200 Clarendon Street, 54th Floor, Boston, MA 02116.

(5) Does not include any common units that may be purchased in a directed unit program.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Immediately following the closing of this offering, Holdings will own common units and subordinated units, representing a combined % limited partner interest in us (or common units and subordinated units, representing a combined % limited partner interest in us, if the underwriters exercise their option to purchase additional common units in full). In addition, Holdings will own and control our general partner, which will own a 2.0% general partner interest in us and all of our incentive distribution rights.

Distributions and Payments to our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and any liquidation of Southcross Energy Partners, L.P. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation Stage	
The consideration received by our general partner and its affiliates prior to or in connection with this offering	common units; subordinated units; all of our incentive distribution rights; and 2.0% general partner interest.
Operational Stage	
Distributions of available cash to our general partner and its affiliates	We will initially make cash distributions 98.0% to our unitholders pro rata, including Holdings, as the holder of an aggregate of common units and subordinated units, and 2.0% to our general partner, assuming it 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, the incentive distribution rights held by our general partner will entitle our general partner to increasing percentages of the distributions, up to 48.0% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $ million on its 2.0% general partner interest and Holdings would receive an annual distribution of approximately $ million on its common units and subordinated units.

Payments to our general partner and its affiliates	Our general partner will not receive a management fee or other compensation for its management of us. However, we will reimburse our general partner and its affiliates for all expenses incurred on our behalf. Our partnership agreement provides that our general partner will determine the amount of these reimbursed expenses. For the twelve months ending June 30, 2013, we estimate that these expenses will be approximately $23.9 million, which includes, among other items, compensation expense for all employees required to manage and operate our business.
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. Please read "The Partnership Agreement Withdrawal or Removal of Our General Partner."
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.

Agreements Governing the Transactions

We and other parties have or will enter into the various documents and agreements with certain of our affiliates, as described in more detail below. These agreements will affect the offering transactions, including the vesting of assets in, and the assumptions of liabilities by, us and our subsidiaries, and the application of the proceeds of this offering. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm's-length negotiations.

Contribution, Conveyance and Assumption Agreement

In connection with the closing of this offering, we will enter into a contribution, conveyance and assumption agreement that will effect the transactions, including the transfer of Holdings' assets and entities to us, and the use of the net proceeds of this offering. While we believe this agreement will be on terms no less favorable to any party than those that could have been negotiated with an unaffiliated third party, it will not be the result of arm's-length negotiations. All of the transaction expenses incurred in connection with these transactions will be paid from proceeds of this offering.

Agreements with Affiliates

Charlesbank and Management's Investments in Holdings

From time to time since its inception, Holdings has issued membership interests in connection with capital contributions from its members, including Charlesbank and certain members of management. For the year ended December 31, 2009, Charlesbank contributed $111.8 million to Holdings and Messrs. Biegler, Hunter, Barcroft, Glasgow and Mueller contributed $1.3 million, $0.8 million, $0.2 million, $0.2 million and $0.1 million, respectively, to Holdings. In conjunction with such capital contribution, a member of management borrowed $150,000 from Holdings to fund his acquisition of equity interests pursuant to a promissory note. The balance of such note was paid in full subsequent to December 31, 2011.

There were no capital contributions for the year ended December 31, 2010. For the year ended December 31, 2011, Charlesbank contributed $14.3 million to Holdings in exchange for redeemable preferred units. During the same period, Messrs. Glasgow and Mueller contributed approximately $28,000 and $18,500, respectively, to Holdings in exchange for redeemable preferred units. For the three months ended March 31, 2012, Charlesbank and certain other institutional investors contributed a total of $35.3 million to Holdings in exchange for redeemable preferred units.

Holdings has not paid any cash distributions to its members.

Corporate Development and Administrative Services Agreement

We entered into a Corporate Development and Administrative Services Agreement, dated as of August 6, 2009, with Charlesbank pursuant to which Charlesbank provides multiple services to us and our subsidiaries, including, among other things: (i) researching, analyzing, structuring and negotiating the terms of investments, acquisitions and dispositions; (ii) researching, identifying, contacting, meeting and negotiating with prospective sources of debt and equity financing; (iii) structuring and establishing the terms of debt and equity financings; and (iv) providing advice in connection with the preparation of our and our subsidiaries' financial and operating plans. Under the terms of the agreement, we pay Charlesbank a monitoring fee of $600,000 per year and reimburse Charlesbank for reasonable fees and expenses it incurs in conjunction with the provision of the services. In addition, we must pay Charlesbank a fee of 1% of (i) the aggregate amount of any cash or capital investment in us or our affiliates by a third party or (ii) the purchase price if we or any of our affiliates consummate a merger or consolidation, acquires beneficial ownership of a majority of the securities of another business or acquires 50% or more of the outstanding voting power of any other business or entity. This agreement will remain in force until (i) the date we and Charlesbank mutually agree to terminate it; (ii) the final distribution in liquidation of us or our subsidiaries; or (iii) the date on which neither Charlesbank nor any of its affiliates own equity securities of us. We and Charlesbank will terminate this agreement upon the completion of this offering.

Procedures for Review, Approval and Ratification of Related-Person Transactions

The board of directors of our general partner will adopt a code of business conduct and ethics in connection with the closing of this offering that will provide that the board of directors of our general partner or its authorized committee will periodically review all related-person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related-person transaction and determines not to so ratify, the code of business conduct and ethics will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The code of business conduct and ethics will provide 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 authorized 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 the code of business conduct and ethics.

The code of business conduct and ethics described above will be adopted in connection with the closing of this offering, and as a result the transactions described above were not reviewed under such policy.

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CONFLICTS OF INTEREST AND DUTIES

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Holdings), on the one hand, and us and our unaffiliated limited partners, on the other hand. The directors and executive officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a duty to manage us in a manner beneficial to us and our unitholders.

The Delaware Revised Uniform Limited Partnership Act, which we refer to as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the fiduciary duties otherwise owed by a general partner to the limited partners and the partnership. Pursuant to these provisions, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner to us and our unitholders with contractual standards governing the duties of the general partner to us and our unitholders and the methods for resolving conflicts of interest. Our partnership agreement also specifically defines the duties our general partner owes to us and our unitholders with respect to actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other, our general partner will resolve that conflict. Our general partner may seek the approval of such resolution from the conflicts committee of the board of directors of our general partner. There is no requirement that our general partner seek the approval of the conflicts committee for the resolution of any conflict, and, under our partnership agreement, our general partner may decide to seek such approval or resolve a conflict of interest in any other way permitted by our partnership agreement, as described below, in its sole discretion. Our general partner will decide whether to refer the matter to the conflicts committee on a case-by-case basis. An independent third party is not required to evaluate the fairness of the resolution.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is:

- approved by the Conflicts Committee, 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 or any of its affiliates;
- 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 between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the Conflicts Committee. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith, *provided* that, if our general partner does not seek approval from the Conflicts Committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points 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 the Partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Any matters approved by the conflicts committee will be conclusively deemed to have been approved in good faith.

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Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the Conflicts Committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement requires someone to act in good faith, it requires that person to subjectively believe that he is acting in the best interests of the partnership or meets the specified standard, for example, a transaction on terms no less favorable to the partnership than those generally being provided to or available from unrelated third parties.

Conflicts of interest could arise in the situations described below, among others.

Affiliates of our general partner may compete with us.

Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner (or as general partner of another company of which we are a partner or member) or those activities incidental to its ownership of interests in us. However, certain affiliates of our general partner, including Charlesbank, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. Additionally, Charlesbank, through its investment funds and managed accounts, makes investments and purchases entities in various areas of the energy sector, including the midstream natural gas industry. These investments and acquisitions may include entities or assets that we would have been interested in acquiring.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to our general partner or any of its affiliates, including its executive officers, directors and Charlesbank. 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. Therefore, Charlesbank may compete with us for investment opportunities and may own an interest in entities that compete with us.

Our general partner is allowed to take into account the interests of parties other than us, such as Charlesbank, in resolving conflicts.

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. 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 or otherwise, free of any duty or obligation whatsoever to us and our unitholders, including any duty to act in the best interests of us or 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 it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of our general partner's limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership.

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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 and limits our general partner's liabilities and the rights of our unitholders with respect to actions that, without the limitations, might constitute breaches of fiduciary duty under applicable Delaware law.

In addition to the provisions described above, our partnership agreement contains provisions that restrict the rights of our unitholders with respect to actions that might otherwise constitute breaches of our general partner's fiduciary duty. 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. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our general partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as such decisions are made in good faith, meaning that it subjectively believed that the decision is 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;

- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the Conflicts Committee and not involving a vote of unitholders must either be (1) on terms no less favorable to us than those generally being provided to or available from unrelated third parties or (2) "fair and reasonable" to us, as determined by our general partner in good faith, *provided* that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

- provides that in resolving conflicts of interest, it will be conclusively deemed that in making its decision the conflicts committee of our general partner's board of directors acted in good faith; and

- provides that our general partner and its executive officers and directors will not be liable for monetary damages to us or our limited partners 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 executive officers or directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that their conduct was criminal.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought Conflicts Committee approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into our securities, and the incurring of any other obligations;

- the purchase, sale or other acquisition or disposition of our securities, or the issuance of additional options, rights, warrants and appreciation rights relating to our securities;

- the mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of our cash;
- the selection and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;
- the maintenance of insurance for our benefit and the benefit of our partners;
- the formation of, or acquisition of an interest in, the contribution of property to, and the making of loans to, any limited or general partnership, joint venture, corporation, limited liability company or other entity;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity, otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense, the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the making of tax, regulatory and other filings, or the rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets; and
- the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Our partnership agreement provides that our general partner must act in "good faith" when making decisions on our behalf, and our partnership agreement further provides that in order for a determination to be made in "good faith," our general partner must have a subjective belief that the determination is in our best interests. Please read "The Partnership Agreement Voting Rights" for information regarding matters that require unitholder approval.

Actions taken by our general partner may affect the amount of cash available for distribution to unitholders or accelerate the right to convert subordinated units.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- the amount and timing of asset purchases and sales;
- cash expenditures and the amount of estimated reserve replacement expenditures;
- borrowings;

- the issuance of additional units; and

- the creation, reduction or increase of reserves in any quarter.

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 an expansion 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 into common units.

In addition, our general partner may use an amount, initially equal to $ million, which would not otherwise constitute available cash from operating surplus, in order to permit the payment of cash distributions on its units and incentive distribution rights. All of these actions may affect the

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amount of cash distributed to our unitholders and our general partner and may facilitate the conversion of subordinated units into common units. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions."

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to our unitholders, including borrowings that have the purpose or effect of:

- enabling our general partner or its affiliates to receive distributions on any subordinated units held by them or the incentive distribution rights; or

- hastening the expiration of the subordination period.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and our subordinated units, our partnership agreement permits us to borrow funds, which would enable us to make this distribution on all outstanding units. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period."

Our partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us, or our operating company and its operating subsidiaries.

We will reimburse our general partner and its affiliates for expenses.

We will reimburse our general partner and its affiliates for costs incurred in managing and operating us. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith, and it will charge on a fully allocated cost basis for services provided to us. The fully allocated basis charged by our general partner does not include a profit component. Please read "Certain Relationships and Related Party Transactions."

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, will not be the result of arm's-length negotiations.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts, and arrangements between us and our general partner and its affiliates are or will be the result of arm's-length negotiations. Similarly, agreements, contracts or arrangements between us and our general partner and its affiliates that are entered into following the closing of this offering will not be required to be negotiated on an arm's-length basis, although, in some circumstances, our general partner may determine that the Conflicts Committee may make a determination on our behalf with respect to such arrangements.

Our general partner and its affiliates will have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically for such use. There is no obligation of our general partner and its affiliates to enter into any contracts of this kind.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that counterparties to such agreements have recourse only against our assets and not against our general partner or its assets or any affiliate of our general partner or its assets. 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 duties, even if we could have obtained terms that are more favorable without the limitation on liability.

Common units are subject to our general partner's limited call right.

Our general partner may exercise its right to call and purchase common units, as provided in our partnership agreement, or may assign this right to one of its affiliates or to us. Our general partner may use its own discretion in determining whether to exercise this right. As a result, a common unitholder may have to sell his common units at an undesirable time or price. Please read "The Partnership Agreement Limited Call Right."

Common unitholders will have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us, on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The attorneys, independent accountants and others who perform services for us have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the Conflicts Committee and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

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 or our unitholders. This election may result in lower distributions to our public 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 the 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. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions Distributions of Available Cash General Partner Interest and Incentive Distribution Rights."

Duties of our General Partner

The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, modify or eliminate, except for the contractual covenant of good faith and fair dealing, the fiduciary duties owed by the general partner to limited partners and the partnership.

Pursuant to these provisions, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner to us and our unitholders with contractual standards governing the duties of the general partner to us and our unitholders and the methods for resolving conflicts of interest. We have adopted these provisions to allow our general partner or its affiliates to engage in transactions with us that would otherwise be prohibited or restricted by state-law fiduciary standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. Without these provisions, such transactions could result in violations of our general partner's state-law fiduciary duty standards. We believe this is appropriate and necessary because the board of directors of our general partner has duties to manage our general partner in a manner beneficial both to its owners, as well as to our unitholders. Without these provisions, our general partner's ability to make decisions involving conflicts of interest would be restricted. These provisions benefit our general partner by enabling it to take into consideration the interests of all parties involved, so long as the resolution is fair and reasonable to us. These provisions also enable our general partner to attract and retain experienced and capable directors. These provisions may be detrimental to our unitholders because they restrict the rights and remedies that would otherwise be available to unitholders for actions that, without those provisions, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest. The following is a summary of:

- the fiduciary duties imposed on general partners of a limited partnership by the Delaware Act in the absence of partnership agreement provisions to the contrary;
- the contractual duties of our general partner contained in our partnership agreement that replace the fiduciary duties that would otherwise be imposed by Delaware law on our general partner; and
- certain rights and remedies of limited partners contained in the Delaware Act.

State law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner of a Delaware limited partnership to use that amount of care that an ordinarily careful and prudent person would use in similar circumstances and to consider all material information reasonably available in making business decisions. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present unless such transactions were entirely fair to the partnership.

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Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in "good faith," meaning that it subjectively believed that the decision was in our best interests and will not be subject to any other standard under applicable law, other than the implied contractual covenant of good faith and fair dealing. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any duty or obligation to us or our limited partners whatsoever, other than the implied contractual covenant of good faith and fair dealing. These standards reduce the obligations to which our general partner would otherwise be held under applicable Delaware law. Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a vote of unitholders or that are not approved by the Conflicts Committee must be: • on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or • "fair and reasonable" to us, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us). If our general partner does not seek approval from the Conflicts Committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the bullet points above, then it will be presumed that, in making its decision, the general partner, acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. These standards reduce the obligations to which our general partner would otherwise be held. In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and its officers and directors will not be liable for monetary damages to us or our

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	limited partners for errors of judgment or for any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that our general partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful.
Rights and remedies of unitholders	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These actions include actions against a general partner for breach of its fiduciary duties or of the partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties, if any, to the limited partners. The Delaware Act provides that, unless otherwise provided in a partnership agreement, a partner or other person shall not be liable to a limited partnership or to another partner or to another person that is a party to or is otherwise bound by a partnership agreement for breach of fiduciary duty for the partner's or other person's good faith reliance on the provisions of the partnership agreement. Under our partnership agreement, to the extent that, at law or in equity, an indemnitee has duties and liabilities relating thereto to us or to our partners, our general partner and any other indemnitee acting in connection with our business or affairs shall not be liable to us or to any partner for its good faith reliance on the provisions of our partnership agreement, and such reliance shall be a defense in any action relating to such duties or liabilities.

By purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

Under our partnership agreement, we must indemnify our general partner and its officers, directors and managers, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that these persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful. We also must provide this indemnification for criminal proceedings when our general partner or these other persons acted with no knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it met the requirements set forth above. To the extent that these provisions purport to include indemnification for liabilities arising under the Securities Act in the opinion of the SEC, such indemnification is contrary to public policy and therefore unenforceable. Please read "The Partnership Agreement Indemnification."

DESCRIPTION OF OUR COMMON UNITS

The Units

The common units represent limited partner interests in us. The holders of common units, along with the holders of subordinated units, are entitled to participate in partnership distributions and are entitled to exercise the rights and privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and subordinated units in and to partnership distributions, please read this section and "Our Cash Distribution Policy and Restrictions on Distributions." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement."

Transfer Agent and Registrar

Duties

will serve as the registrar and transfer agent for the common units. We will pay all fees charged by the transfer agent for transfers of common units except the following that must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates, or to cover taxes and other governmental charges in connection therewith;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There will be no charge to our unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their respective stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and has accepted the appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement;
- represents and warrants that the transferee has the right, power, authority and capacity to enter into our partnership agreement; and

gives the consents, waivers and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

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Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing the transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

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THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please read "Provisions of Our Partnership Agreement Relating to Cash Distributions";
- with regard to the duties of our general partner, please read "Conflicts of Interest and Duties";
- with regard to the transfer of common units, please read "Description of Our Common Units Transfer of Common Units"; and
- with regard to allocations of taxable income and taxable loss, please read "Material Federal Income Tax Consequences."

Organization and Duration

We were organized in Delaware in April 2012 and have a perpetual existence.

Purpose

Our purpose under our partnership agreement is limited to any business activities that are approved by our general partner and in any event that lawfully may be conducted by a limited partnership organized under Delaware law; *provided* that our general partner may not cause us to engage, directly or indirectly, in any business activity that our general partner determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the power to cause us, our operating company and its subsidiaries to engage in activities other than the business of gathering, compressing, treating and transporting natural gas and the fractionation of NGLs, our general partner has no current plans to do so and may decline to do so free of any duty or obligation whatsoever to us or our unitholders. Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Cash Distributions

Our partnership agreement specifies the manner in which we will make cash distributions to holders of our common units and other partnership securities as well as to our general partner in respect of its general partner interest and its incentive distribution rights. For a description of these cash distribution provisions, please read "Provisions of Our Partnership Agreement Relating to Cash Distributions."

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under " Limited Liability."

For a discussion of our general partner's right to contribute capital to maintain its 2.0% general partner interest if we issue additional units, please read " Issuance of Additional Securities."

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Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that require the approval of a "unit majority" require:

- during the subordination period, the approval of a majority of the outstanding common units, excluding those common units held by our general partner and its affiliates, and a majority of the outstanding subordinated units, voting as separate classes; and
- after the subordination period, the approval of a majority of the outstanding common units.

By virtue of the exclusion of those common units held by our general partner and its affiliates from the required vote, and by their ownership of all of the subordinated units, during the subordination period our general partner and its affiliates do not have the ability to ensure passage of, but do have the ability to ensure defeat of, any amendment that requires a unit majority.

In voting their common and subordinated units, our general partner and its affiliates will have no duty or obligation whatsoever to us or our unitholders, including any duty to act in the best interests of us or our unitholders.

Issuance of additional units	No approval right.
Amendment of our partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read " Amendment of Our Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. Please read " Merger, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please read " Termination and Dissolution."
Continuation of our business upon dissolution	Unit majority. Please read " Termination and Dissolution."
Withdrawal of our general partner	Under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to , 2022 in a manner that would cause a dissolution of our partnership. Please read " Withdrawal or Removal of Our General Partner."
Removal of our general partner	Not less than $66^2/_3\%$ of the outstanding units, voting as a single class, including units held by our general partner and its affiliates. Please read " Withdrawal or Removal of Our General Partner."

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Transfer of our general partner interest	Our general partner may transfer all, but not less than all, of its general partner interest in us without a vote of our unitholders to an affiliate or another person in connection with its merger or consolidation with or into, or sale of all or substantially all of its assets to, such person. The approval of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, is required in other circumstances for a transfer of the general partner interest to a third party prior to , 2022. Please read " Transfer of General Partner Interest."
Transfer of incentive distribution rights	No approval rights. Please read " Transfer of Incentive Distribution Rights."
Transfer of ownership interests in our general partner	No approval required at any time. Please read " Transfer of Ownership Interests in Our General Partner."

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that it otherwise acts in conformity with the provisions of our partnership agreement, its liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital it is obligated to contribute to us for its common units plus its share of any undistributed profits and assets. If it were determined, however, that the right of, or exercise of the right by, the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us who reasonably believe that a limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for such a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of its assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to it at the time it became a limited partner and that could not be ascertained from the partnership agreement.

Our subsidiaries conduct business primarily in three states and we may have subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as a member of our operating company may require compliance with legal requirements in the jurisdictions in which our operating company conducts business, including qualifying our subsidiaries to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership interest in our operating company or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by our general partner without the approval of our limited partners.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit our subsidiaries from issuing equity securities, which may effectively rank senior to the common units.

Upon issuance of additional partnership securities (other than the issuance of common units upon exercise by the underwriters of their option to purchase additional common units, the issuance of common units upon conversion of outstanding subordinated units or the issuance of common units upon a reset of the incentive distribution rights), our general partner will be entitled, but not required, to make additional capital contributions to the extent necessary to maintain its 2.0% general partner interest in us. Our general partner's 2.0% interest in us will be reduced if we issue additional units in the future (other than in those circumstances described above) and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of the general partner and its affiliates, including such interest represented by common and subordinated units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights under our partnership agreement to acquire additional common units or other partnership securities.

Amendment of Our Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any duty or obligation whatsoever to us or our unitholders, including any duty to act in the best interest of us or our unitholders. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner must seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option.

The provision of our partnership agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 90.0% of the outstanding units, voting as a single class (including units owned by our general partner and its affiliates). Upon the closing of this offering, affiliates of our general partner will own approximately % of the outstanding common and subordinated units.

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate for us to qualify or to continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we, our operating company, nor its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- a change in our fiscal year or taxable year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents, or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940 or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974,

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- or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary or appropriate in connection with the authorization of issuance of additional partnership securities or rights to acquire partnership securities;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated, or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership, joint venture, limited liability company or other entity, as otherwise permitted by our partnership agreement;
- mergers with, conveyances to or conversions into another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the merger, conveyance or conversion other than those it receives by way of the merger, conveyance or conversion; or
- any other amendments substantially similar to any of the matters described above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect in any material respect the limited partners considered as a whole or any particular class of partnership interests as compared to other classes of partnership interests;
- are necessary or appropriate to satisfy any requirements, conditions, or guidelines contained in any opinion, directive, order, ruling, or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of units or to comply with any rule, regulation, guideline, or requirement of any securities exchange on which the units are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Limited Partner Approval

Our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in our being treated as an entity for federal income tax purposes in connection with any of the amendments described above under " No Unitholder Approval." No other amendments to our partnership agreement will become effective without the approval of holders of at least 90.0% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced.

Merger, Sale or Other Disposition of Assets

A merger or consolidation of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger or consolidation and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interest of us or our unitholders.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our and our subsidiaries' assets in a single transaction or a series of related transactions, including by way of merger, consolidation, other combination or sale of ownership interests of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate, or grant a security interest in all or substantially all of our and our subsidiaries' assets without that approval. Our general partner may also sell all or substantially all of our and our subsidiaries' assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of the limited partners), each of our units will be an identical unit of our partnership following the transaction and the partnership securities to be issued do not exceed 20.0% of our outstanding partnership securities immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed limited liability entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters and the governing instruments of the new entity provide the limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until dissolved under our partnership agreement. We will dissolve upon:

- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal following the approval and admission of a successor general partner;
- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- the entry of a decree of judicial dissolution of our partnership; or
- there being no limited partners, unless we are continued without dissolution in accordance with the Delaware Act.

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Upon a dissolution under the first clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement and appoint as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither we nor any of our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time if it determines that an immediate sale or distribution would be impractical or would cause undue loss to our partners. The liquidator may distribute our assets, in whole or in part, in kind if it determines that a sale would be impractical or would cause undue loss to the partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to , 2022 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by the general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after , 2022, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving at least 90 days' advance notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50.0% of the outstanding common units are held or controlled by one person and its affiliates, other than our general partner and its affiliates. In addition, our partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest and incentive distribution rights in us without the approval of the unitholders. Please read " Transfer of General Partner Interest" and " Transfer of Incentive Distribution Rights."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period of time after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read " Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than $66^2/_3$% of all outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units, and a majority of the outstanding subordinated units, voting as a single class. The ownership of more than $33^1/_3$% of the outstanding units by our general partner and its affiliates gives them the ability to

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prevent our general partner's removal. At the closing of this offering, affiliates of our general partner will own % of the outstanding common and subordinated units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist:

- the subordinated units held by any person will immediately and automatically convert into common units on a one-for-one basis, provided (i) neither such person nor any of its affiliates voted any of its units in favor of the removal and (ii) such person is not an affiliate of the successor general partner; and

- if all of the subordinated units convert pursuant to the foregoing, all cumulative common unit arrearages on the common units will be extinguished and the subordination period will end

In the event of removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its incentive distribution rights for their fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest and its incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due to it, including, without limitation, all employee-related liabilities, including severance liabilities, incurred in connection with the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Except for transfer by our general partner of all, but not less than all, of its general partner interest to:

- an affiliate of our general partner (other than an individual); or

- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity, our general partner may not transfer all or any of its general partner interest to another person prior to , 2022 without the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

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Our general partner and its affiliates may, at any time, transfer units to one or more persons, without unitholder approval, except that they may not transfer subordinated units to us.

Transfer of Ownership Interests in Our General Partner

At any time, the owners of our general partner may sell or transfer all or part of their ownership interests in our general partner to an affiliate or a third party without the approval of our unitholders.

Transfer of Incentive Distribution Rights

Our general partner or any other holder of incentive distribution rights may transfer any or all of its incentive distribution rights without unitholder approval.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change our management. Please read " Withdrawal or Removal of Our General Partner" for a discussion of certain consequences of the removal of our general partner. If any person or group, other than our general partner and its affiliates, acquires beneficial ownership of 20.0% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units directly from our general partner or its affiliates or any transferee of that person or group that is approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors of our general partner. Please read " Meetings; Voting."

Limited Call Right

If at any time our general partner and its affiliates own more than 80.0% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the remaining limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10, but not more than 60, days notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

- the average of the daily closing prices of the partnership securities of such class for the 20 consecutive trading days preceding the date three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or price. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please read "Material Federal Income Tax Consequences Disposition of Common Units."

Meetings; Voting

Except as described below regarding a person or group owning 20.0% or more of any class of units then outstanding, unitholders who are record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

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Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20.0% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage. The units representing the general partner interest are units for distribution and allocation purposes, but do not entitle our general partner to any vote other than its rights as general partner under our partnership agreement, will not be entitled to vote on any action required or permitted to be taken by the unitholders and will not count toward or be considered outstanding when calculating required votes, determining the presence of a quorum, or for similar purposes.

Each record holder of a unit has a vote according to its percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "Issuance of Additional Securities." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, acquires, in the aggregate, beneficial ownership of 20.0% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum, or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and its nominee provides otherwise. Except as our partnership agreement otherwise provides, subordinated units will vote together with common units as a single class.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units will be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Except as described above under "Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Assignees; Redemption

If our general partner, with the advice of counsel, determines we are subject to U.S. federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the nationality, citizenship or other related status of our member (and their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose nationality, citizenship or other related status creates substantial risk of cancellation or forfeiture of any property or who fails to comply

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with the procedures instituted by our general partner to obtain proof of the nationality, citizenship or other related status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Non-Taxpaying Assignees; Redemption

In the event any rates that we charge our customers become regulated by the Federal Energy Regulatory Commission, to avoid any adverse effect on the maximum applicable rates chargeable to customers by us, or in order to reverse an adverse determination that has occurred regarding such maximum rate, our partnership agreement provides our general partner the power to amend the agreement. If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the U.S. federal income tax status of our member (and their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our general partner to obtain proof of the U.S. federal income tax status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Indemnification

Under our partnership agreement, we will indemnify the following persons, in most circumstances, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;

- any departing general partner;

- any person who is or was an affiliate of our general partner or any departing general partner;

- any person who is or was a member, manager, partner, director, officer, fiduciary or trustee of our partnership, our subsidiaries, our general partner, any departing general partner or any of their affiliates;

- any person who is or was serving at the request of the general partner or any departing general partner as an officer, director, member, manager, partner, fiduciary or trustee of another person; and

- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or loan funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

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Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine in good faith the expenses that are allocable to us. For the twelve months ending June 30, 2013, we estimate that these expenses will be approximately $23.9 million, which includes, among other items, compensation expense for all employees required to manage and operate our business.

Books and Reports

Our general partner is required to keep or cause to be kept appropriate books and records of our business at our principal offices. The books will be maintained for both tax and financial reporting purposes on an accrual basis. For fiscal and tax reporting purposes, we use the calendar year.

We will furnish or make available to record holders of common units, within 90 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants, including a balance sheet and statements of operations, and our equity and cash flows. Except for our fourth quarter, we will also furnish or make available summary financial information within 45 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website that we maintain.

We will furnish each record holder with information reasonably required for federal and state tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining its federal and state tax liability and filing its federal and state income tax returns, regardless of whether he supplies us with the necessary information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to its interest as a limited partner, upon reasonable demand and at its own expense, have furnished to him:

- a current list of the name and last known business, residence or mailing address of each partner;
- a copy of our federal, state and local income tax returns;
- true and full information as to the amount of cash, and a description and statement of the net agreed value of any other capital contribution by each partner and that each partner has agreed to contribute in the future, and the date on which each became a partner;
- copies of our partnership agreement, the certificate of limited partnership of the partnership, related amendments, and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

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Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units, or other partnership securities proposed to be sold by our general partner or any of its affiliates, other than individuals, or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years and for so long thereafter as is required for the holder to sell its partnership securities following any withdrawal or removal of Southcross Energy Partners GP, LLC as our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and commissions. Please read "Units Eligible for Future Sale."

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered by this prospectus, Holdings will hold an aggregate of common units and subordinated units (or common units and subordinated units if the underwriters exercise their option to purchase additional units in full). All of the subordinated units will convert into common units at the end of the subordination period. The sale of these common and subordinated units could have an adverse impact on the price of the common units or on any trading market that may develop.

The common units sold in this offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units held by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1.0% of the total number of the securities outstanding; or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least six months (provided we are in compliance with the current public information requirement) or one year (regardless of whether we are in compliance with the current public information requirement), would be entitled to sell common units under Rule 144 without regard to the rule's public information requirements, volume limitations, manner of sale provisions and notice requirements.

Our partnership agreement provides that we may issue an unlimited number of limited partner interests of any type without a vote of the unitholders at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. Please read "The Partnership Agreement Issuance of Additional Securities."

Under our partnership agreement, our general partner and its affiliates, excluding any individual who is an affiliate of our general partner, have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any common units that they hold. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any common units to require registration of any of these common units and to include any of these common units in a registration by us of other common units, including common units offered by us or by any unitholder. Our general partner and its affiliates will continue to have these registration rights for two years following the withdrawal or removal of our general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts and commissions. Except as described below, our general partner and its affiliates may sell their common units in private transactions at any time, subject to compliance with applicable laws.

We, Holdings, Charlesbank, our general partner and each of our general partner's directors and officers have agreed that for a period of 180 days from the date of this prospectus they will not, without the prior written consent of Citigroup Global Markets Inc. and Wells Fargo Securities, LLC, dispose of or hedge any common units or any securities convertible into or exchangeable for our common units. Please read "Underwriting" for a description of these lock-up provisions.

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MATERIAL FEDERAL INCOME TAX CONSEQUENCES

This section is a summary of the material tax considerations that may be relevant to prospective unitholders who are individual citizens or residents of the U.S. and, unless otherwise noted in the following discussion, is the opinion of Latham & Watkins LLP, counsel to our general partner and us, insofar as it relates to legal conclusions with respect to matters of U.S. federal income tax law. This section is based upon current provisions of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"), existing and proposed Treasury regulations promulgated under the Internal Revenue Code (the "Treasury Regulations") and current administrative rulings and court decisions, all of which are subject to change. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to "us" or "we" are references to Southcross Energy Partners, L.P. and our operating subsidiaries.

The following discussion does not comment on all federal income tax matters affecting us or our unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the U.S. and has only limited application to corporations, estates, entities treated as partnerships for U.S. federal income tax purposes, trusts, nonresident aliens, U.S. expatriates and former citizens or long-term residents of the United States or other unitholders subject to specialized tax treatment, such as banks, insurance companies and other financial institutions, tax-exempt institutions, foreign persons (including, without limitation, controlled foreign corporations, passive foreign investment companies and non-U.S. persons eligible for the benefits of an applicable income tax treaty with the United States), IRAs, real estate investment trusts (REITs) or mutual funds, dealers in securities or currencies, traders in securities, U.S. persons whose "functional currency" is not the U.S. dollar, persons holding their units as part of a "straddle," "hedge," "conversion transaction" or other risk reduction transaction, and persons deemed to sell their units under the constructive sale provisions of the Code. In addition, the discussion only comments, to a limited extent, on state, local, and foreign tax consequences. Accordingly, we encourage each prospective unitholder to consult his own tax advisor in analyzing the state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. Instead, we will rely on opinions of Latham & Watkins LLP. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the common units and the prices at which common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

All statements as to matters of federal income tax law and legal conclusions with respect thereto, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Latham & Watkins LLP and are based on the accuracy of the representations made by us.

For the reasons described below, Latham & Watkins LLP has not rendered an opinion with respect to the following specific federal income tax issues: (i) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please read " Tax Consequences of Unit Ownership Treatment of Short Sales"); (ii) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read " Disposition of Common Units Allocations Between Transferors and Transferees"); and

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(iii) whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please read " Tax Consequences of Unit Ownership Section 754 Election" and " Uniformity of Units").

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable to the partnership or the partner unless the amount of cash distributed to him is in excess of the partner's adjusted basis in his partnership interest. Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation, processing, storage, refining and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than % of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and our general partner and a review of the applicable legal authorities, Latham & Watkins LLP is of the opinion that at least 90% of our current gross income constitutes qualifying income. The portion of our income that is qualifying income may change from time to time.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our status or the status of our operating subsidiaries for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Latham & Watkins LLP on such matters. It is the opinion of Latham & Watkins LLP that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below that:

- We will be classified as a partnership for federal income tax purposes; and

- Each of our operating subsidiaries will be disregarded as an entity separate from us for federal income tax purposes.

In rendering its opinion, Latham & Watkins LLP has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Latham & Watkins LLP has relied include:

- Neither we nor the operating subsidiaries has elected or will elect to be treated as a corporation; and

- For each taxable year, more than 90% of our gross income has been and will be income of the type that Latham & Watkins LLP has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code.

We believe that these representations have been true in the past and expect that these representations will continue to be true in the future.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxed as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as taxable dividend income, to the extent of our current and accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Latham & Watkins LLP's opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders of Southcross Energy Partners, L.P. will be treated as partners of Southcross Energy Partners, L.P. for federal income tax purposes. Also, unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of Southcross Energy Partners, L.P. for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please read " Tax Consequences of Unit Ownership Treatment of Short Sales."

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their tax advisors with respect to their tax consequences of holding common units in Southcross Energy Partners, L.P. The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Southcross Energy Partners, L.P. for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income

Subject to the discussion below under " Entity-Level Collections," we will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether we make cash distributions to him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

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Treatment of Distributions

Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of the common units, taxable in accordance with the rules described under " Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution by us of cash to that unitholder. To the extent our distributions cause a unitholder's "at-risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please read " Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. This deemed distribution may constitute a non-pro rata distribution. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, depletion recapture and/or substantially appreciated "inventory items," each as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, the unitholder will be treated as having been distributed his proportionate share of the Section 751 Assets and then having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (i) the non-pro rata portion of that distribution over (ii) the unitholder's tax basis (generally zero) for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions

We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2014, will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be % or less of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders will increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution on all units and other assumptions with respect to capital expenditures, cash flow, net working capital and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct.

The actual percentage of distributions that will constitute taxable income could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be greater, and perhaps substantially greater, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to make minimum quarterly distributions on all units, yet we only distribute the minimum quarterly distributions on all units; or we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering.

Basis of Common Units

A unitholder's initial tax basis for his common units will be the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner to the extent of the general partner's "net value" as defined in regulations under Section 752 of the Internal Revenue Code, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please read " Disposition of Common Units Recognition of Gain or Loss."

Limitations on Deductibility of Losses

The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder, estate, trust, or corporate unitholder (if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by or for five or fewer individuals or some tax-exempt organizations) to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A common unitholder subject to these limitations must recapture losses deducted in previous years to the extent that distributions cause his at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such common unitholder's tax basis in his common units. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain would no longer be utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by (i) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (ii) any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at-risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

In addition to the basis and at-risk limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or a unitholder's investments in

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other publicly traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive loss limitations are applied after other applicable limitations on deductions, including the at-risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitations on Interest Deductions

The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment or (if applicable) qualified dividend income. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections

If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the unitholder on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual unitholder in which event the unitholder would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction

In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among our general partner and the unitholders in accordance with their percentage interests in us. At any time that distributions are made to the common units in excess of distributions to the subordinated units, or incentive distributions are made to our general partner, gross income will be allocated to the recipients to the extent of these distributions. If we have a net loss, that loss will be allocated first to our general partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to our general partner.

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Specified items of our income, gain, loss and deduction will be allocated to account for (i) any difference between the tax basis and fair market value of our assets at the time of an offering and (ii) any difference between the tax basis and fair market value of any property contributed to us by the general partner and its affiliates that exists at the time of such contribution, together referred to in this discussion as the "Contributed Property." The effect of these allocations, referred to as Section 704(c) Allocations, to a unitholder purchasing common units from us in this offering will be essentially the same as if the tax bases of our assets were equal to their fair market values at the time of this offering. In the event we issue additional common units or engage in certain other transactions in the future, "reverse Section 704(c) Allocations," similar to the Section 704(c) Allocations described above, will be made to the general partner and all of our unitholders immediately prior to such issuance or other transactions to account for the difference between the "book" basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of such issuance or future transaction. In addition, items of recapture income will be allocated to the extent possible to the unitholder who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner sufficient to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity," will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction only if the allocation has "substantial economic effect." In any other case, a partner's share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Latham & Watkins LLP is of the opinion that, with the exception of the issues described in " Section 754 Election" and " Disposition of Common Units Allocations Between Transferors and Transferees," allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss or deduction.

Treatment of Short Sales

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

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Because there is no direct or indirect controlling authority on the issue relating to partnership interests, Latham & Watkins LLP has not rendered an opinion regarding the tax treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read " Disposition of Common Units Recognition of Gain or Loss."

Alternative Minimum Tax

Each unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective unitholders are urged to consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

Tax Rates

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 35% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than twelve months) of individuals is 15%. However, absent new legislation extending the current rates, beginning January 1, 2013, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. Moreover, these rates are subject to change by new legislation at any time.

The recently enacted Patient Protection and Affordable Care Act of 2010, as amended by the Health Care and Education Reconciliation Act of 2010 is scheduled to impose a 3.8% Medicare tax on certain net investment income earned by individuals, estates and trusts for taxable years beginning after December 31, 2012. For these purposes, net investment income generally includes a unitholder's allocable share of our income and gain realized by a unitholder from a sale of units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income or (ii) the amount by which the unitholder's modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if the unitholder is married and filing separately) or $200,000 (in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Section 754 Election

We will make the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS unless there is a constructive termination of the partnership. Please read " Disposition of Common Units Constructive Termination." The election will generally permit us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply with respect to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, the inside basis in our assets with respect to a unitholder will be considered to have two components: (i) his share of our tax basis in our assets ("common basis") and (ii) his Section 743(b) adjustment to that basis.

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We will adopt the remedial allocation method as to all our properties. Where the remedial allocation method is adopted, the Treasury Regulations under Section 743 of the Internal Revenue Code require a portion of the Section 743(b) adjustment that is attributable to recovery property that is subject to depreciation under Section 168 of the Internal Revenue Code and whose book basis is in excess of its tax basis to be depreciated over the remaining cost recovery period for the property's unamortized Book-Tax Disparity. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. Under our partnership agreement, our general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these and any other Treasury Regulations. Please read " Uniformity of Units."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as non-amortizable to the extent attributable to property which is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please read " Uniformity of Units." A unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate the common unitholder's basis in his common units, which may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read " Disposition of Common Units Recognition of Gain or Loss." Latham & Watkins LLP is unable to opine as to whether our method for depreciating Section 743 adjustments is sustainable for property subject to depreciation under Section 167 of the Internal Revenue Code or if we use an aggregate approach as described above, as there is no direct or indirect controlling authority addressing the validity of these positions. Moreover, the IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the units. If such a challenge were sustained, the gain from the sale of units might be increased without the benefit of additional deductions.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation deductions and his share of any gain or loss on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer, or if we distribute property and have a substantial basis reduction. Generally, a built-in loss or a basis reduction is substantial if it exceeds $250,000.

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The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than twelve months of our income, gain, loss and deduction. Please read " Disposition of Common Units Allocations Between Transferors and Transferees."

Initial Tax Basis, Depreciation and Amortization

The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to (i) this offering will be borne by our general partner and its affiliates, and (ii) any other offering will be borne by our general partner and all of our unitholders as of that time. Please read " Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods, including bonus depreciation to the extent available, that will result in the largest deductions being taken in the early years after assets subject to these allowances are placed in service. Please read " Uniformity of Units." Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please read " Tax Consequences of Unit Ownership Allocation of Income, Gain, Loss and Deduction" and " Disposition of Common Units Recognition of Gain or Loss."

The costs we incur in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties.

The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss

Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us that in the aggregate were in excess of cumulative net taxable income for a common unit and, therefore, decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held for more than twelve months will generally be taxed at a maximum U.S. federal income tax rate of 15%. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred.

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Thus, according to the ruling discussed above, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, he may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract;

in each case, with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees

In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Internal Revenue Code and most publicly traded partnerships use similar simplifying conventions, the use of this method may not be permitted under existing Treasury Regulations as there is no direct or indirect controlling authority on this issue. Recently, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, although such tax items must be prorated on a daily basis. Existing publicly traded partnerships are entitled to rely on these proposed Treasury Regulations; however, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued. Accordingly, Latham & Watkins LLP is unable to opine on the validity of this method of allocating income and deductions between transferor and transferee unitholders because the issue has not been finally resolved by the IRS or the courts. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between transferor and transferee unitholders, as well as unitholders whose interests vary during a taxable year, to conform to a method permitted under

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future Treasury Regulations. A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the U.S. and who effects the sale or exchange through a broker who will satisfy such requirements.

Constructive Termination

We will be considered to have been terminated for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. A constructive termination results in the closing of our taxable year for all unitholders. 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 result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and unitholders could receive two Schedules K-1 if the relief discussed below is not available) for one fiscal year and the cost of the preparation of these returns will be borne by all common unitholders. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination. The IRS has recently announced a publicly traded partnership technical termination relief procedure whereby if a publicly traded partnership that has technically terminated requests publicly traded partnership technical termination relief and the IRS grants such relief, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please read "Tax Consequences of Unit Ownership Section 754 Election." We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as nonamortizable, to the extent attributable to property the common basis of which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code, even though that position may be

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inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. Please read " Tax Consequences of Unit Ownership Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. In either case, and as stated above under " Tax Consequences of Unit Ownership Section 754 Election," Latham & Watkins LLP has not rendered an opinion with respect to these methods. Moreover, the IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please read " Disposition of Common Units Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other foreign persons raises issues unique to those investors and, as described below to a limited extent, may have substantially adverse tax consequences to them. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units. Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to it.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the U.S. because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, our quarterly distribution to foreign unitholders will be subject to withholding at the highest applicable effective tax rate. Each foreign unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a U.S. trade or business, that corporation may be subject to the U.S. branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our earnings and profits, as adjusted for changes in the foreign corporation's "U.S. net equity," that is effectively connected with the conduct of a U.S. trade or business. That tax may be reduced or eliminated by an income tax treaty between the U.S. and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

A foreign unitholder who sells or otherwise disposes of a common unit will be subject to U.S. federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the foreign unitholder. Under a ruling published by the IRS, interpreting the scope of "effectively connected income," a foreign unitholder would be considered to be engaged in a trade or business in the U.S. by virtue of the U.S. activities of the partnership, and part or all of that unitholder's gain would be effectively connected with that unitholder's indirect U.S. trade or business. Moreover, under the Foreign Investment in Real Property Tax Act, a foreign common unitholder generally will be subject to U.S. federal income tax upon the sale or disposition of a common unit if (i) he owned (directly or constructively applying certain attribution rules) more than 5% of our common units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such unitholder held the common units or the five-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests and we do not expect that to change in the foreseeable future. Therefore, foreign unitholders may be subject to federal income tax on gain from the sale or disposition of their units.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Latham & Watkins LLP can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. 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 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.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. Our partnership agreement names our general partner as our Tax Matters Partner.

The Tax Matters Partner has made and will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- whether the beneficial owner is:

  (1) a person that is not a U.S. person;

  (2) a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

  (3) a tax-exempt entity;

- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from dispositions.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $100 per failure, up to a maximum of $1,500,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties.

An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, "substantial authority"; or
- as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty. More stringent rules apply to "tax shelters," which we do not believe includes us, or any of our investments, plans or arrangements.

A substantial valuation misstatement exists if (a) the value of any property, or the adjusted basis of any property, claimed on a tax return is 150% or more of the amount determined to be the correct amount of the valuation or adjusted basis, (b) the price for any property or services (or for the use of property) claimed on any such return with respect to any transaction between persons described in Internal Revenue Code Section 482 is 200% or more (or 50% or less) of the amount determined under Section 482 to be the correct amount of such price, or (c) the net Internal Revenue Code Section 482 transfer price adjustment for the taxable year exceeds the lesser of $5 million or 10% of the taxpayer's gross receipts. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 200% or more than the correct valuation or certain other thresholds are met, the penalty imposed increases to 40%. We do not anticipate making any valuation misstatements.

In addition, the 20% accuracy-related penalty also applies to any portion of an underpayment of tax that is attributable to transactions lacking economic substance. To the extent that such transactions are not disclosed, the penalty imposed is increased to 40%. Additionally, there is no reasonable cause defense to the imposition of this penalty to such transactions.

Reportable Transactions.

If we were to engage in a "reportable transaction," we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses for partnerships, individuals, S corporations, and trusts in excess of $2 million in any single year, or $4 million in any combination of six successive tax years. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) would be audited by the IRS. Please read " Information Returns and Audit Procedures."

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, you may be subject to the following additional consequences:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at " Accuracy-Related Penalties.";

- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability; and

- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any "reportable transactions."

Recent Legislative Developments

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, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Currently, one such legislative proposal would eliminate the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. Please read " Partnership Status." We are unable to predict whether any such changes will ultimately be enacted.

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However, it is possible that a change in law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our units.

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you likely will be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We will initially own property or do business in Texas, Mississippi and Alabama. Some of these states impose a personal income tax on individuals; certain of these states also impose an income tax on corporations and other entities. We may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in many of these jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some of the jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please read " Tax Consequences of Unit Ownership Entity-Level Collections." Based on current law and our estimate of our future operations, our general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent states, localities and foreign jurisdictions, of his investment in us. Accordingly, each prospective unitholder is urged to consult his own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as U.S. federal tax returns, that may be required of him. Latham & Watkins LLP has not rendered an opinion on the state, local or foreign tax consequences of an investment in us.

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INVESTMENT IN SOUTHCROSS ENERGY PARTNERS, L.P. BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and the restrictions imposed by Section 4975 of the Internal Revenue Code and provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Internal Revenue Code or ERISA, collectively, "Similar Laws." For these purposes the term "employee benefit plan" includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs or annuities established or maintained by an employer or employee organization, and entities whose underlying assets are considered to include "plan assets" of such plans, accounts and arrangements, collectively, "Employee Benefit Plans." Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;

- whether in making the investment, the plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;

- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please read "Material Federal Income Tax Consequences Tax-Exempt Organizations and Other Investors"; and

- whether making such an investment will comply with the delegation of control and prohibited transaction provisions of ERISA, the Internal Revenue Code and any other applicable Similar Laws.

The person with investment discretion with respect to the assets of an Employee Benefit Plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit Employee Benefit Plans from engaging, either directly or indirectly, in specified transactions involving "plan assets" with parties that, with respect to the Employee Benefit Plan, are "parties in interest" under ERISA or "disqualified persons" under the Internal Revenue Code unless an exemption is available. A party in interest or disqualified person who engages in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Internal Revenue Code. In addition, the fiduciary of the ERISA plan that engaged in such a non-exempt prohibited transaction may be subject to penalties and liabilities under ERISA and the Internal Revenue Code.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary should consider whether the Employee Benefit Plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that our general partner would also be a fiduciary of such Employee Benefit Plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code, ERISA and any other applicable Similar Laws.

The Department of Labor regulations and Section 3(42) of ERISA provide guidance with respect to whether, in certain circumstances, the assets of an entity in which Employee Benefit Plans acquire equity interests would be deemed "plan assets." Under these rules, an entity's assets would not be considered to be "plan assets" if, among other things:

(a) the equity interests acquired by the Employee Benefit Plan are publicly offered securities i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, are freely transferable and are registered under certain provisions of the federal securities laws;

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(b) the entity is an "operating company," i.e., it is primarily engaged in the production or sale of a product or service, other than the investment of capital, either directly or through a majority-owned subsidiary or subsidiaries; or

(c) there is no significant investment by "benefit plan investors," which is defined to mean that less than 25% of the value of each class of equity interest, disregarding any such interests held by our general partner, its affiliates and some other persons, is held generally by Employee Benefit Plans.

Our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in (a) and (b) above.

In light of the serious penalties imposed on persons who engage in prohibited transactions or other violations, plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA, the Internal Revenue Code and other Similar Laws.

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UNDERWRITING

Citigroup Global Markets Inc. and Wells Fargo Securities, LLC are acting as joint book-running managers of the offering and as representatives of the underwriters named below. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, each underwriter named below has severally agreed to purchase, and we have agreed to sell to that underwriter, the number of common units set forth opposite the underwriter's name.

Underwriter	Number of Common Units
Citigroup Global Markets Inc.	
Wells Fargo Securities, LLC	
Total	

The underwriting agreement provides that the obligations of the underwriters to purchase the common units included in this offering are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all of the common units (other than those covered by the over-allotment option described below) if they purchase any of the common units.

Common units sold by the underwriters to the public will initially be offered at the initial public offering price set forth on the cover of this prospectus. Any common units sold by the underwriters to securities dealers may be sold at a discount from the initial public offering price not to exceed $ per common unit. If all the common units are not sold at the initial offering price, the underwriters may change the offering price and the other selling terms. The representatives have advised us that the underwriters do not intend to make sales to discretionary accounts.

If the underwriters sell more common units than the total number set forth in the table above, we have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to additional common units at the public offering price less the underwriting discount and the structuring fee. The underwriters may exercise the option solely for the purpose of covering over-allotments, if any, in connection with this offering. To the extent the option is exercised, each underwriter must purchase a number of additional common units approximately proportionate to that underwriter's initial purchase commitment. Any common units issued or sold under the option will be issued and sold on the same terms and conditions as the other common units that are the subject of this offering.

We, our general partner, each of our general partner's officers and directors, Holdings and Charlesbank, have agreed that, for a period of 180 days from the date of this prospectus, we and they will not, without the prior written consent of Citigroup Global Markets Inc. and Wells Fargo Securities, LLC, dispose of or hedge any common units or any securities convertible into or exchangeable for our common units. Citigroup Global Markets Inc. and Wells Fargo Securities, LLC, in their sole discretion, may release any of the securities subject to these lock-up agreements at any time, which, in the case of our officers and directors shall be with notice. Notwithstanding the foregoing, if (i) during the last 17 days of the 180-day restricted period, we issue an earnings release or material news or a material event relating to our partnership occurs or (ii) prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day restricted period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

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At our request, the underwriters have reserved up to % of the common units being offered by this prospectus for sale at the initial public offering price to the directors, officers and employees of our general partner and certain other persons associated with us through a directed unit program. The number of common units available for sale to the general public will be reduced by the number of directed units purchased by participants in the program. Except for certain of the officers and directors of our general partner who have entered into lock-up agreements as contemplated in the immediately preceding paragraph, each person buying common units through the directed unit program has agreed that, for a period of days from the date of this prospectus, he or she will not, without the prior written consent of Citigroup Global Markets Inc. and Wells Fargo Securities, LLC, dispose of or hedge any common units or any securities convertible into or exchangeable for our common units with respect to common units purchased in the program. For certain officers and directors purchasing common units through the directed unit program, the lock-up agreements contemplated in the immediately preceding paragraph shall govern with respect to their purchases. Citigroup Global Markets Inc. and Wells Fargo Securities, LLC in their sole discretion may release any of the securities subject to these lock-up agreements at any time without notice. Any directed units not purchased will be offered by the underwriters to the general public on the same basis as all other common units offered. We have agreed to indemnify the underwriters against certain liabilities and expenses, including liabilities under the Securities Act, in connection with the sales of the directed units.

Prior to this offering, there has been no public market for our common units. Consequently, the initial public offering price for the common units will be determined by negotiations between us and the representatives. Among the factors to be considered in determining the initial public offering price are our results of operations, our current financial condition, our future prospects, our markets, the economic conditions in and future prospects for the industry in which we compete, our management, and currently prevailing general conditions in the equity securities markets, including current market valuations of publicly traded partnerships considered comparable to our partnership. We cannot assure you, however, that the price at which the common units will sell in the public market after this offering will not be lower than the initial public offering price or that an active trading market in our common units will develop and continue after this offering.

We intend to apply to have our common units listed on the New York Stock Exchange under the symbol "SXE."

The following table shows the underwriting discounts and commissions that we are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' over-allotment option.

	Paid by Southcross Energy Partners, L.P.	
	No Exercise	**Full Exercise**
Per common unit	$	$
Total	$	$

In addition, we will pay Citigroup Global Markets Inc. and Wells Fargo Securities a structuring fee equal to % of the gross proceeds of this offering, or $ ($ if the underwriters exercise the over-allotment option in full), for the evaluation, analysis and structuring of our partnership.

We estimate that the expenses of the offering, not including the underwriting discount or structuring fee, will be approximately $ million, all of which will be paid by us.

In connection with the offering, the underwriters may purchase and sell common units in the open market. Purchases and sales in the open market may include short sales, purchases to cover short positions, which may include purchases pursuant to the over-allotment option, and stabilizing purchases.

- Short sales involve secondary market sales by the underwriters of a greater number of common units than they are required to purchase in the offering.

  - "Covered" short sales are sales of common units in an amount up to the number of common units represented by the underwriters' over-allotment option.

  - "Naked" short sales are sales of common units in an amount in excess of the number of common units represented by the underwriters' over-allotment option.

- Covering transactions involve purchases of common units either pursuant to the underwriters' over-allotment option or in the open market after the distribution has been completed in order to cover short positions.

  - To close a naked short position, the underwriters must purchase common units in the open market after the distribution has been completed. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.

  - To close a covered short position, the underwriters must purchase common units in the open market after the distribution has been completed or must exercise the over-allotment option. In determining the source of common units to close the covered short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through the over-allotment option.

- Stabilizing transactions involve bids to purchase common units so long as the stabilizing bids do not exceed a specified maximum.

Purchases to cover short positions and stabilizing purchases, as well as other purchases by the underwriters for their own accounts, may have the effect of preventing or retarding a decline in the market price of the common units. They may also cause the price of the common units to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on the New York Stock Exchange, in the over-the-counter market or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time.

The underwriters are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. The underwriters or their affiliates have in the past performed commercial banking, investment banking and advisory services for us from time to time for which they have received customary fees and reimbursement of expenses and may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business for which they may receive customary fees and reimbursement of expenses. Affiliates of Citigroup Global Markets Inc. and Wells Fargo Securities, LLC are lenders under our existing credit facility and, in that respect, will receive a portion of the net proceeds from this offering. Additionally, affiliates of certain of the underwriters will serve as lenders under our new credit facility. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve our securities and instruments. Affiliates of Wells Fargo Securities, LLC own approximately 3.7% and 8.3% of Holdings' outstanding common and preferred units, respectively. Holdings may use a portion of the cash distribution it receives from us to redeem all or a portion of

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Holdings' outstanding redeemeable preferred units. In that respect, affiliates of certain of the underwriters that own such preferred securities may receive a portion of the net proceeds from this offering.

We, our general partner and certain of our affiliates have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make because of any of those liabilities.

Because the Financial Industry Regulatory Authority is expected to view the common units offered hereby as interests in a direct participation program, this offering is being made in compliance with Rule 2310 of the FINRA Rules. Investor suitability with respect to the common units will be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

Notice to Prospective Investors in Germany

This document has not been prepared in accordance with the requirements for a securities or sales prospectus under the German Securities Prospectus Act (*Wertpapierprospektgesetz*), the German Sales Prospectus Act (*Verkaufsprospektgesetz*), or the German Investment Act (*Investmentgesetz*). Neither the German Federal Financial Services Supervisory Authority (*Bundesanstalt für Finanzdienstleistungsaufsicht* BaFin) nor any other German authority has been notified of the intention to distribute the common units in Germany. Consequently, the common units may not be distributed in Germany by way of public offering, public advertisement or in any similar manner and this document and any other document relating to the offering, as well as information or statements contained therein, may not be supplied to the public in Germany or used in connection with any offer for subscription of the common units to the public in Germany or any other means of public marketing. The common units are being offered and sold in Germany only to qualified investors which are referred to in Section 3, paragraph 2 no. 1 in connection with Section 2 no. 6 of the German Securities Prospectus Act, Section 8f paragraph 2 no. 4 of the German Sales Prospectus Act, and in Section 2 paragraph 11 sentence 2 no.1 of the German Investment Act. This document is strictly for use of the person who has received it. It may not be forwarded to other persons or published in Germany.

The offering does not constitute an offer to buy or the solicitation or an offer to sell the common units in any circumstances in which such offer or solicitation is unlawful.

Notice to Prospective Investors in the Netherlands

The common units may not be offered or sold, directly or indirectly, in the Netherlands, other than to qualified investors (gekwalificeerde beleggers) within the meaning of Article 1:1 of the Dutch Financial Supervision Act (Wet op het financieel toezicht).

Notice to Prospective Investors in Switzerland

This prospectus is being communicated in Switzerland to a small number of selected investors only. Each copy of this document is addressed to a specifically named recipient and may not be copied, reproduced, distributed or passed on to third parties. The common units are not being offered to the public in Switzerland, and neither this prospectus, nor any other offering materials relating to the common units may be distributed in connection with any such public offering.

Our partnership has not been registered with the Swiss Financial Market Supervisory Authority FINMA as a foreign collective investment scheme pursuant to Article 120 of the Collective Investment Schemes Act of June 23, 2006 ("CISA"). Accordingly, the common units may not be offered to the public in or from Switzerland, and neither this prospectus, nor any other offering materials relating to the common units may be made available through a public offering in or from Switzerland. The common units may only be offered and this prospectus may only be distributed in or from Switzerland by way of private placement exclusively to qualified investors (as this term is defined in the CISA and its implementing ordinance).

Notice to Prospective Investors in the United Kingdom

Our partnership may constitute a "collective investment scheme" as defined by section 235 of the Financial Services and Markets Act 2000 ("FSMA") that is not a "recognised collective investment scheme" for the purposes of FSMA ("CIS") and that has not been authorised or otherwise approved. As an unregulated scheme, it cannot be marketed in the United Kingdom to the general public, except in accordance with FSMA. This prospectus is only being distributed in the United Kingdom to, and are only directed at:

i) if our partnership is a CIS and is marketed by a person who is an authorised person under FSMA, (a) investment professionals falling within Article 14(5) of the Financial Services and Markets Act 2000 (Promotion of Collective Investment Schemes) Order 2001, as amended (the "CIS Promotion Order") or (b) high net worth companies and other persons falling with Article 22(2)(a) to (d) of the CIS Promotion Order; or

ii) otherwise, if marketed by a person who is not an authorised person under FSMA, (a) persons who fall within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the "Financial Promotion Order") or (b) Article 49(2)(a) to (d) of the Financial Promotion Order; and

iii) in both cases (i) and (ii) to any other person to whom it may otherwise lawfully be made, (all such persons together being referred to as "relevant persons"). The common units are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such common units will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

Each Joint Book-Running Manager has represented, warranted and agreed that:

(a) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of FSMA) received by it in connection with the issue or sale of any common units which are the subject of the offering contemplated by this prospectus (the "Securities") in circumstances in which Section 21(1) of FSMA does not apply to our partnership; and

(b) it has complied and will comply with all applicable provisions of FSMA with respect to anything done by it in relation to the Securities in, from or otherwise involving the United Kingdom.

Notice to Prospective Investors in the European Economic Area

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), other than Germany, with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of securities described in this prospectus may not be made to the public in that relevant member state other than:

- to any legal entity which is a qualified investor as defined in the Prospectus Directive;

- to fewer than 100 or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by the Issuer for any such offer; or

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in any other circumstances falling within Article 3(2) of the Prospectus Directive;

provided that no such offer of securities shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an "offer of securities to the public" in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase or subscribe for the securities, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression "Prospectus Directive" means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in the Relevant Member State, and includes any relevant implementing measure in each relevant member state. The expression 2010 PD Amending Directive means Directive 2010/73/EU.

We have not authorized and do not authorize the making of any offer of securities through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the securities as contemplated in this prospectus. Accordingly, no purchaser of the securities, other than the underwriters, is authorized to make any further offer of the securities on behalf of us or the underwriters.

VALIDITY OF THE COMMON UNITS

The validity of the common units offered hereby will be passed upon for us by Latham & Watkins LLP, Houston, Texas. Certain legal matters in connection with the common units offered hereby will be passed upon for the underwriters by Baker Botts L.L.P., Dallas, Texas.

EXPERTS

The consolidated financial statements as of December 31, 2010 and 2011, and for the period from June 2, 2009 (date of inception) to December 31, 2009 and the years ended December 31, 2010 and 2011, of Southcross Energy LLC and subsidiaries and combined financial statements for the period from January 1, 2009 to July 31, 2009 of Southcross Energy Predecessor included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein (which report expresses an unqualified opinion and includes an explanatory paragraph related to Southcross Energy LLC's acquisition of entities and assets from Crosstex Energy, L.P. effective August 1, 2009). The financial statements of Enterprise Alabama Intrastate, LLC as of and for the year ended December 31, 2010 included in this prospectus have been audited by Deloitte & Touche LLP, independent auditors, as stated in their report appearing herein. The balance sheet as of April 19, 2012 of Southcross Energy Partners, L.P. included in this prospectus has also been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein. Such financial statements have been so included in reliance upon the reports of such firm given upon their authority as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 regarding the common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and the common units offered in this prospectus, you may desire to review the full registration statement, including the exhibits. The registration statement, including the exhibits, may be inspected and copied at the public reference facilities maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of this material can also be obtained upon written request from the Public Reference Section of the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549 at prescribed rates or from the SEC's web site on the Internet at http://www.sec.gov. Please call the SEC at 1-800-SEC-0330 for further information on public reference rooms.

As a result of the offering, we will file with or furnish to the SEC periodic reports and other information. These reports and other information may be inspected and copied at the public reference facilities maintained by the SEC or obtained from the SEC's website as provided above. Our website is located at , and we expect to make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

We intend to furnish or make available to our unitholders annual reports containing our audited financial statements prepared in accordance with GAAP. Our annual report will contain a detailed statement of any transactions with our general partner or its affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to our general partner or its affiliates for the fiscal year completed, showing the amount paid or accrued to each recipient and the services performed. We also intend to furnish or make available to our unitholders quarterly reports containing our unaudited interim financial information, including the information required by Form 10-Q, for the first three fiscal quarters of each fiscal year.

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FORWARD-LOOKING STATEMENTS

Some of the information in this prospectus may contain forward-looking statements. These statements can be identified by the use of forward-looking terminology including "will," "may," "believe," "expect," "anticipate," "estimate," "continue," or other similar words. These statements discuss future expectations, contain projections of financial condition or of results of operations, or state other "forward-looking" information. These forward-looking statements involve risks and uncertainties. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this prospectus. The risk factors and other factors noted throughout this prospectus could cause our actual results to differ materially from those contained in any forward-looking statement.

INDEX TO FINANCIAL STATEMENTS

SOUTHCROSS ENERGY PARTNERS, L.P.

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

Summary

Introduction

Set forth below are the unaudited pro forma consolidated balance sheet of Southcross Energy Partners, L.P. as of March 31, 2012 and the unaudited pro forma consolidated statements of operations of Southcross Energy Partners, L.P. for the year ended December 31, 2011 and the three months ended March 31, 2012. References to "we," "us" and "our" mean Southcross Energy Partners, L.P. and its consolidated subsidiaries, unless the context requires otherwise.

Our unaudited pro forma balance sheet, which presents the pro forma effects of the recapitalization transactions related to this offering described under "Summary Recapitalization Transactions and Partnership Structure" in the prospectus as if such transactions occurred on March 31, 2012, has been derived from and should be read in conjunction with, the unaudited condensed consolidated historical financial statements of Southcross Energy LLC, our predecessor for accounting purposes, included elsewhere in this prospectus. Our unaudited pro forma consolidated statement of operations for the year ended December 31, 2011 that present the pro forma effects of the EAI acquisition described below under " Unaudited Pro Forma Consolidated Statement of Operations" and the effects of the recapitalization transactions as if the acquisition and the recapitalization transactions occurred on January 1, 2011, has been derived from, and should be read in conjunction with, the audited historical financial statements of Southcross Energy LLC included elsewhere in this prospectus and the audited and unaudited financial statements of Enterprise Alabama Intrastate, LLC included elsewhere in this prospectus. Our unaudited pro forma consolidated statements of operations for the three months ended March 31, 2012 assume the recapitalization transactions occurred as of January 1, 2011 and are derived from, and should be read in conjunction with the unaudited condensed consolidated financial statements of Southcross Energy LLC included elsewhere in this prospectus. We have not made pro forma adjustments to our audited historical consolidated balance sheet as of March 31, 2012 for the EAI acquisition (as defined below) because that acquisition occurred on September 1, 2011, and, therefore, the effects of that acquisition are already reflected.

Our unaudited pro forma consolidated financial statements are based on certain assumptions and do not purport to be indicative of the results that actually would have been achieved if the recapitalization transactions and the EAI acquisition, as applicable, had been completed on the date set forth above. Moreover, they do not project our financial position or results of operations as of any future date or for any future period.

Unaudited Pro Forma Consolidated Balance Sheet

Our unaudited pro forma consolidated balance sheet as of March 31, 2012 is derived from the unaudited historical condensed consolidated balance sheet of Southcross Energy LLC as of March 31, 2012. The "Adjustments for Recapitalization Transactions" column in our unaudited pro forma consolidated balance sheet contains the adjustments that we believe are appropriate to give effect to the recapitalization transactions that will occur in connection with our initial public offering (the "Offering") assuming such transactions occurred on March 31, 2012. Please read " Note 1. Pro Forma Consolidated Balance Sheet Adjustments." The Offering Transactions have the effect of:

- eliminating the members' equity and the preferred units of Southcross Energy LLC, which will not be a part of our capital structure;

- reflecting the conveyance of Southcross Operating LLC to us in exchange for (i) a 2.0% general partner's interest in us and our incentive distribution rights, (ii) common units,

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SOUTHCROSS ENERGY PARTNERS, L.P.

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS (Continued)

representing a % limited partner interest in us, and (iii) subordinated units representing a % limited partner interest in us;

issuing to the public common units, representing a % limited partner interest in us;

using the net proceeds from the Offering to (i) make a cash distribution to Holdings of $ million, a portion of which will be used to reimburse Holdings for certain capital expenditures it incurred with respect to assets it contributed to us; (ii) repay $ million of debt outstanding under our existing credit facility; (iii) pay Citigroup Global Markets Inc. and Wells Fargo Securities, LLC an aggregate structuring fee of $ million; and (iv) pay estimated offering expenses of $ million; and

using the net proceeds from borrowing approximately $ million under our new credit facility (i) to make an aggregate distribution to Holdings of approximately $ million and (ii) to pay fees and expenses relating to our new credit facility of approximately $ million.

Unaudited Pro Forma Consolidated Statement of Operations

On September 1, 2011, Southcross Energy LLC acquired Enterprise Alabama Intrastate LLC ("EAI"). Our unaudited pro forma consolidated statements of operations for the year ended December 31, 2011 are derived from the audited historical consolidated statement of operations of Southcross Energy LLC for the year ended December 31, 2011 and the unaudited statement of income for Enterprise Alabama Intrastate, LLC for the eight-month period ended August 31, 2011, not included in this prospectus. Our unaudited pro forma consolidated statements of operations for the three months ended March 31, 2012 are derived from the unaudited condensed consolidated financials of Southcross Energy LLC included elsewhere in this prospectus.

The "Pro Forma Adjustments" column in our unaudited pro forma consolidated statements of operations for the year ended December 31, 2011 contains the adjustments that we believe are appropriate to present the EAI acquisition on a pro forma basis assuming a January 1, 2011 acquisition date. Please read " Note 2. Pro Forma Consolidated Statement of Operations Adjustments." These adjustments include adjustments (i) in depreciation and amortization expense, over the eight-month period from January 1, 2011 to August 31, 2011 (the "Stub Period"), due to a new fair value basis of assets as a result of change in control accounting, (ii) in interest expense reflecting higher debt as a result of funding the acquisition as of January 1, 2011, and (iii) to reflect the entering into of the amended and restated credit agreement as of January 1, 2011 in order to provide the debt capacity to finance the EAI acquisition as of that date.

The "Adjustments for Recapitalization Transactions" column in our unaudited pro forma consolidated statements of operations for the year ended December 31, 2011 and the three months ended March 31, 2012 contains the adjustments that we believe are appropriate to give effect to the recapitalization transactions that will occur in connection with the offering assuming such transactions occurred on January 1, 2011. Please read " Note 2. Pro Forma Consolidated Statement of Operations Adjustments." We have not made adjustments to give effect to the incremental general and administrative expenses of approximately $2.2 million that we expect to incur as a result of being a publicly traded partnership. These adjustments include adjustments to interest expense reflecting the new credit facility that we would enter into as part of the recapitalization transactions assuming a January 1, 2011 offering date. We have assumed an interest rate of 4.0% and debt level of $180.0 million, as well as new deferred financing cost amortization on the basis of the recapitalization transactions.

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SOUTHCROSS ENERGY PARTNERS, L.P.

UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET

AS OF MARCH 31, 2012

	Southcross Energy LLC	Adjustments for Recapitalization Transactions	Pro Forma as Adjusted
		(Dollars in thousands)	
ASSETS			
CURRENT ASSETS:			
Cash and cash equivalents	$ 13,985	$ (b)	$
		( )(b)	
		237,408 (b)	
		( )(b)	
		(c)	
		( )(c)	
		( )(c)	
Trade accounts receivable	35,670		35,670
Prepaid expenses	495		495
Other current assets	348		348
PROPERTY, PLANT, AND EQUIPMENT, NET	411,825		411,825
INTANGIBLE ASSETS	1,667		1,667
OTHER ASSETS	6,820	(c)	
TOTAL ASSETS	$ 470,810	$	$
LIABILITIES, PREFERRED UNITS AND MEMBERS' EQUITY			
CURRENT LIABILITIES:			
Accounts payable	$ 47,372		$ 47,372
Interest payable	48		48
Current maturities of long-term debt	17,490	(17,490)(b)	
Other current liabilities	2,865		2,865
Total current liabilities	$ 67,775	$ (17,490)	$ 50,285
LONG-TERM DEBT	219,918	(219,918)(b)	
		(c)	
DERIVATIVE LIABILITY	243		243
Total liabilities	$ 287,936	$	$
COMMITMENTS AND CONTINGENCIES			
REDEEMABLE PREFERRED UNITS	17,296	(17,296)(a)	
REDEEMABLE PREFERRED UNITS SERIES B	35,492	(35,492)(a)	
PREFERRED UNITS	153,995	(153,995)(a)	
MEMBERS' EQUITY			
Total members' equity	(23,909)	(b)	
		( )(b)	
Common Units held by public		(b)	
General partner and affiliates			

Common units				(a)		
Subordinated units				(a)		
General Partner Interest				(a)		
TOTAL LIABILITIES AND CAPITAL	$	470,810	$		$	

See accompanying notes to the unaudited pro forma consolidated financial statements.

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SOUTHCROSS ENERGY PARTNERS, L.P.

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS

YEAR ENDED DECEMBER 31, 2011

	Southcross Energy LLC	Enterprise Alabama Intrastate, LLC January 1, 2011 to August 31, 2011	Pro Forma Adjustments (Note 2)	Pro Forma	Adjustments for Recapitalization Transactions (Note 2)	Pro Forma As Adjusted
	(Dollars in thousands, except for per share data)					
TOTAL REVENUE	$ 523,149	$ 25,003	$	$ 548,152	$	$ 548,152
EXPENSES:						
Cost of natural gas and liquids sold	460,580	18,796		479,376		479,376
Operations and maintenance	24,707	3,994		28,701		28,701
Depreciation and amortization	12,345	972	(117)(d)	13,200		13,200
General and administrative	8,926	386		9,312		9,312
Transaction costs	203			203		203
Total expenses	506,761	24,148	(117)	530,792		530,792
INCOME FROM OPERATIONS	16,388	855	117	17,360		17,360
INTEREST INCOME	24			24		24
LOSS ON EXTINGUISHMENT OF DEBT	(3,240)			(3,240)		(3,240)
INTEREST EXPENSE	(5,372)		(314)(e)	(5,686)	(1,621)(f)	(7,307)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE	7,800	855	(197)	8,458	(1,621)	6,837
INCOME TAX EXPENSE	(261)			(261)		(261)
NET INCOME (LOSS)	$ 7,539	$ 855	$ (197)	$ 8,197	$ (1,621)	$ 6,576
Less: deemed dividend on Redeemable Preferred Units	1,553			1,553		
deemed dividend on Preferred Units	14,131			14,131		
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON UNITHOLDERS	$ (8,145)	$ 855	$ (197)	$ (7,487)		
NET LOSS ATTRIBUTABLE TO COMMON UNITHOLDERS (BASIC AND DILUTED)	$ (6.79)			$ (6.25)		
SOUTHCROSS ENERGY PARTNERS, L.P. PRO FORMA EARNINGS PER UNIT						
General partner interest in net income						$
Common unitholders' interest in net income						$
Subordinated unitholders' interest in net income						$
Net income per common unit (basic and diluted)						$
Net income per subordinated unit (basic and diluted)						$

See accompanying notes to the unaudited pro forma consolidated financial statements.

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SOUTHCROSS ENERGY PARTNERS, L.P.

UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS

THREE MONTHS ENDED MARCH 31, 2012

	Southcross Energy LLC	Pro Forma Adjustments	Pro Forma	Adjustments for Recapitalization Transactions	Pro Forma as Adjusted
	(Dollars in thousands, except for per unit data)				
TOTAL REVENUE	$ 120,617		$ 120,617	$	$ 120,617
EXPENSES:					
Cost of natural gas and liquids sold	99,202		99,202		99,202
Operations and maintenance	7,197		7,197		7,197
Depreciation and amortization	3,665		3,665		3,665
General and administrative	2,433		2,433		2,433
Total expenses	112,497		112,497		112,497
INCOME FROM OPERATIONS	8,120		8,120		8,120
INTEREST INCOME	2		2		2
INTEREST EXPENSE	(1,801)		(1,801)	589(g)	(1,212)
INCOME BEFORE INCOME TAX EXPENSE	6,321		6,321	589	6,910
INCOME TAX EXPENSE	(85)		(85)		(85)
NET INCOME	$ 6,236		$ 6,236	$ 589	$ 6,825
Less: deemed dividend on Redeemable Preferred Units	742		742		
deemed dividend on Series B Redeemable Preferred Units	192		192		
deemed dividend on Preferred Units	3,746		3,746		
NET INCOME ATTRIBUTABLE TO COMMON UNITHOLDERS	$ 1,556		$ 1,556		
NET INCOME ATTRIBUTABLE TO COMMON UNITHOLDERS	$ 1.28		$ 1.28		
basic					
diluted	$ 1.07		$ 1.07		
SOUTHCROSS ENERGY PARTNERS, L.P. PRO FORMA EARNINGS PER UNIT					
General partner interest in net income					$
Common unitholders' interest in net income					$
Subordinated unitholders' interest in net income					$
Net income per common unit (basic and diluted)					$
Net income per subordinated unit (basic and diluted)					$

See accompanying notes to the unaudited pro forma consolidated financial statements.

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SOUTHCROSS ENERGY PARTNERS, L.P.

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. PRO FORMA CONSOLIDATED BALANCE SHEET ADJUSTMENTS

(a)

Reflects adjustments for the recapitalization transactions based on an assumption that such transactions occurred on March 31, 2012. These adjustments will have the effect of:

- eliminating the members' equity and the preferred units of Southcross Energy LLC, which will not be a part of our capital structure;

- reflecting the conveyance of Southcross Operating LLC to us in exchange for (i) a 2.0% general partner interest in us and our incentive distribution rights, (ii) common units, representing a % limited partner interest in us, and (iii) subordinated units representing a % limited partner interest in us;

(b)

Reflects adjustments for the recapitalization transactions not discussed in Note 1(a) above, based on an assumption that such transactions occurred on March 31, 2012. These adjustments are based upon the following assumptions:

- gross proceeds of $ million received from the issuance and sale of common units at an assumed initial offering price of $ per unit (the midpoint of the range set forth on the cover page of this prospectus);

- cash distribution to Holdings of $ million, a portion of which will be used to reimburse Holdings for certain capital expenditures it incurred with respect to assets contributed to us; and

- pay estimated underwriting fees and commissions and offering expenses of $ million.

(c)

Reflects adjustments for the recapitalization transactions not discussed in Notes 1(a) and 1(b) above, based on an assumption that such transactions occurred on March 31, 2012. These adjustments are based upon the following assumptions:

- total borrowings of $ million under our new credit facility;

- cash payment to Holdings of approximately $ million; and

- pay total fees relating to our new credit facility of $ million.

NOTE 2. PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS ADJUSTMENTS

(d)

Reflects the net effect of the elimination of depreciation expense attributable to the operations we purchased from Enterprise GTM Holdings L.P. ("Enterprise"), the addition of depreciation expense we would have incurred based on a January 1, 2011 assumed acquisition date and the addition of amortization expense we would have incurred based on a January 1, 2011 assumed acquisition date. Our net adjustment to depreciation and amortization expense is a decrease of $117,000 and is attributable to the following:

a decrease in depreciation expense of $155,000 reflecting the fair value and useful lives that we have assigned to the assets we acquired as compared to Enterprise's carrying value and useful lives; and

an increase in our amortization expense of $38,000 for the Stub Period reflecting the amortization of the value of the intangible assets that we acquired.

(e) As a result of the EAI acquisition, interest expense increased $314,000 over the Stub Period. This increase was due to Southcross Energy LLC incurring $21.8 million additional debt to fund the

SOUTHCROSS ENERGY PARTNERS, L.P.

NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 2. PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS ADJUSTMENTS (Continued)

EAI acquisition, offset by lower deferred financing fees resulting from the amended and restated credit agreement. EAI recorded no historical interest expense for the eight months ended August 31, 2011.

(f) Reflects the net increase of $1,621,000 of interest expense for the year ended December 31, 2011 as a result of entering into the new credit facility, which is part of the recapitalization transactions, assuming a January 1, 2011 offering date. We will borrow $180.0 million at an annual interest rate of 4.0%. The increase is due to increased debt outstanding under the new credit facility as compared to the average loan balance outstanding during 2011, higher deferred financing fees reflecting the increased loan capacity under the new credit facility and increased revolver commitment costs. If we were to incur an additional 1.0% interest at the closing of this offering, the additional cost would be approximately $1.8 million.

(g) Reflects the net decrease of $589,000 of interest expense for the three months ended March 31, 2012 as a result of entering into the new credit facility, which is part of the Offering Transactions, assuming a January 1, 2011 offering date. The decrease is due primarily to less debt outstanding under the new credit facility as compared to the average loan balance outstanding under the existing credit facility during the first quarter of 2012. Part of the proceeds from the Offering Transactions are being used to repay debt outstanding as of March 31, 2012 from $237. 4 million to $180.0 million.

NOTE 3. PRO FORMA EARNINGS PER UNIT

Pro forma net income per unit is determined by dividing the pro forma net earnings available to common and subordinated unitholders of us by the number of common and subordinated units resulting from the Offering Transactions. For purposes of this calculation, the number of common and subordinated units outstanding was assumed to be units and units, respectively. If the underwriters fully exercise their option to purchase additional common units, the total number of common units outstanding on a pro forma basis will not change. If the incentive distribution rights to be issued to our general partner had been issued on January 1, 2011, then based on the amount of pro forma net income for the year ended December 31, 2011 and the three months ended March 31, 2012, no distribution to our general partner would have been made. Accordingly, no effect has been given to the incentive distribution rights in computing pro forma earnings per common unit for the year ended December 31, 2011 or the three months ended March 31, 2012.

All units were assumed to have been outstanding since the beginning of the periods presented. Basic and diluted pro forma net earnings per unit are the same, as there are no potentially dilutive units expected to be outstanding at the closing of the offering.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

AS OF DECEMBER 31, 2011 AND MARCH 31, 2012

(Dollars in thousands)

	December 31, 2011	March 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,412	$ 13,985
Trade accounts receivable	41,234	35,670
Prepaid expenses	950	495
Other current assets	561	348
Total current assets	44,157	50,498
PROPERTY, PLANT, AND EQUIPMENT, NET	369,861	411,825
INTANGIBLE ASSETS	1,681	1,667
OTHER ASSETS	4,686	6,820
TOTAL ASSETS	$ 420,385	$ 470,810
LIABILITIES, PREFERRED UNITS AND MEMBERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 50,439	$ 47,372
Interest payable	24	48
Current maturities of long term debt	17,490	17,490
Other current liabilities	4,983	2,865
Total current liabilities	72,936	67,775
LONG TERM DEBT	190,790	219,918
DERIVATIVE LIABILITY	21	243
Total liabilities	263,747	287,936
COMMITMENTS AND CONTINGENCIES (Note 10)		
REDEEMABLE PREFERRED UNITS	16,554	17,296
REDEEMABLE PREFERRED UNITS SERIES B		35,492
PREFERRED UNITS	150,249	153,995
MEMBERS' EQUITY		
Common equity Class A (1,415,729 and 1,313,455 common units authorized and outstanding as of December 31, 2011 and March 31, 2012, respectively)	1,416	1,313
Common equity Class B (57,279 and 28,639 common units authorized and outstanding as of December 31, 2011 and March 31, 2012, respectively)	57	29
Accumulated Deficit	(11,638)	(25,251)
Total members' equity	(10,165)	(23,909)
TOTAL LIABILITIES, PREFERRED UNITS AND MEMBERS' EQUITY	$ 420,385	$ 470,810

See accompanying notes to the condensed consolidated financial statements.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE THREE MONTHS ENDED MARCH 31, 2011 AND MARCH 31, 2012

(Dollars in thousands, except for per unit data)

	Three Months Ended March 31,	
	2011	**2012**
TOTAL REVENUE	$ 120,999	$ 120,617
EXPENSES:		
Cost of natural gas and liquids sold	105,752	99,202
Operations and maintenance	4,834	7,197
Depreciation and amortization	2,795	3,665
General, and administrative	1,970	2,433
Total expenses	115,351	112,497
INCOME FROM OPERATIONS	5,648	8,120
INTEREST INCOME	8	2
INTEREST EXPENSE	(1,634)	(1,801)
INCOME BEFORE INCOME TAX EXPENSE	4,022	6,321
INCOME TAX EXPENSE	(65)	(85)
NET INCOME	$ 3,957	$ 6,236
Less: deemed dividend on Redeemable Preferred Units		742
deemed dividend on Series B Redeemable Preferred Units		192
deemed dividend on Preferred Units	3,356	3,746
NET INCOME ATTRIBUTABLE TO COMMON UNITHOLDERS	$ 601	$ 1,556
Net Income per unit basic	$ 0.50	$ 1.28
Net Income per unit diluted	$ 0.41	$ 1.07

See accompanying notes to the condensed consolidated financial statements.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

FOR THE THREE MONTHS ENDED MARCH 31, 2011 AND MARCH 31, 2012

(Dollars in thousands)

	Common Equity	Accumulated Deficit	Total Members' Equity
BALANCE OF MEMBERS' EQUITY December 31, 2010	$ 1,472	$ (3,493)	$ (2,021)
Net income		3,957	3,957
Deemed dividend on Preferred Units		(3,356)	(3,356)
BALANCE OF MEMBERS' EQUITY March 31, 2011	$ 1,472	$ (2,892)	$ (1,420)
BALANCE OF MEMBERS' EQUITY December 31, 2011	$ 1,473	$ (11,638)	(10,165)
Net income		6,236	6,236
Deemed dividend on Redeemable Preferred Units		(742)	(742)
Deemed Dividend on Series B Redeemable Preferred Units		(192)	(192)
Deemed Dividend on Preferred Units		(3,746)	(3,746)
Repurchase and retirement of common units	(131)	(15,169)	(15,300)
BALANCE OF MEMBERS' EQUITY March 31, 2012	$ 1,342	$ (25,251)	(23,909)

See accompanying notes to the condensed consolidated financial statements.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE THREE MONTHS ENDED MARCH 31, 2011 AND MARCH 31, 2012

(Dollars in thousands)

	Three Months ended March 31,	
	2011	**2012**
OPERATING ACTIVITIES:		
Net income	$ 3,957	6,236
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	2,795	3,665
Deferred financing fees amortization	303	283
Gain on sale of property, plant and equipment	(522)	
Unrealized derivative loss	186	222
Changes in operating assets and liabilities:		
Accounts receivable	2,117	5,564
Prepaid expenses and other	257	668
Other non current assets	(15)	(135)
Accounts payable	(5,539)	(9,768)
Interest payable	(1,514)	24
Accrued expenses and other current liabilities	(1,753)	(2,121)
Net cash provided by operating activities	272	4,638
INVESTING ACTIVITIES:		
Capital expenditures	(15,404)	(38,912)
Sale of property, plant and equipment	522	
Net cash provided by investing activities	(14,882)	(38,912)
FINANCING ACTIVITIES:		
Borrowings under revolving credit facility		33,500
Repayment of long-term debt	(4,766)	(4,372)
Financing costs		(2,281)
Repurchase and retirement of common units		(15,300)
Proceeds from issuance of Series B Redeemable Preferred Units		35,300
Net cash provided by (used by) financing activities	(4,766)	46,847
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(19,376)	12,573
CASH AND CASH EQUIVALENTS Beginning of period	20,323	1,412
CASH AND CASH EQUIVALENTS End of period	$ 947	$ 13,985

See accompanying notes to the condensed consolidated financial statements.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

1. ORGANIZATION AND PRESENTATION

Organization

Southcross Energy LLC (a Delaware limited liability company) and subsidiaries (collectively, "we" or the "Company") was formed on June 2, 2009, (the "Inception Date"). The Company's principal operations commenced with the acquisition of certain entities and assets (the "Predecessor" or "Southcross Energy Predecessor") from Crosstex Energy, L.P. ("Crosstex") on August 6, 2009 (effective August 1, 2009) (the "Acquisition").

The Company is a midstream pipeline company that provides natural gas gathering, processing, treating, compression and transportation services and natural gas liquid ("NGL") fractionation services to its producer customers, and also sources, purchases, transports and sells natural gas and NGLs to its power generation, industrial and utility customers. The Company's assets are located in South Texas, Mississippi, and Alabama. Effective September 1, 2011, the Company completed the acquisition of Enterprise Alabama Intrastate, LLC ("EAI") for $21.8 million. The Company is controlled through investment funds and entities associated with Charlesbank Capital Partners, LLC ("Charlesbank").

Basis of Presentation and Principles of Consolidation

The Company has prepared these unaudited condensed consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP') for interim financial information. The accompanying condensed consolidated statements include the accounts of Southcross Energy LLC and its controlled subsidiaries. All of the Company's subsidiaries are wholly owned, either directly or indirectly through wholly owned subsidiaries. All inter-company accounts and transactions have been eliminated in the preparation of the accompanying financial statements.

The results of operations for the three months ended March 31, 2012 are not necessarily indicative of results expected for the full year. In our opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate and make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC. These unaudited condensed consolidated interim financial statements and the notes thereto should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2011.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the financial statements as well as the reported amounts of revenues and expenses during the reporting periods. Although these estimates are based on management's best available knowledge of current and future events, actual results may differ from those estimates.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Subsequent events have been evaluated through June 1, 2012, the date these financial statements were available to be issued.

Revenue Recognition The Company records revenue and related costs for gas and NGL sales and transportation services in the period in which they are earned. Revenue primarily consists of the sale of natural gas and liquids along with fees earned from its gathering and processing operations. Under certain agreements, the Company purchases natural gas from producers at receipt points on the pipeline systems, and then sells the natural gas, or produced NGLs, if any, at delivery points on its systems. The Company records revenue and cost of product sold on a gross basis for these transactions where the Company acts as principal and takes title to the natural gas. The Company also has contracts where it does not take title to the gas and charges fees for providing services such as gathering, treating or transportation and the Company records these fees separately in revenues as Transportation, gathering and processing fees. The Company recognizes revenue when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectability is reasonable assured.

For the three months ended March 31, 2011 and 2012, respectively, the Company had the following revenue by category:

	Southcross Energy LLC For the Three Months ended March 31,	
	2011	**2012**
	(in $ thousands)	
Revenue		
Sales of natural gas	$ 90,431	$ 73,270
NGL's and condensate sales	23,578	36,817
Transportation, gathering, and processing fees	6,414	10,448
Other	576	82
Total revenue	$ 120,999	$ 120,617

The Company derives revenue in its business from the following types of arrangements:

Fixed-Fee. The Company receives a fee per unit of natural gas or NGL volume that it gathers at the wellhead, processes, treats, fractionates, compresses and transports. Some of the Company's arrangements also provide for a fixed fee for guaranteed transportation capacity on its systems.

Fixed-Spread. Under these arrangements, the Company purchases natural gas from producers or suppliers at receipt points on its systems at an index price less a fixed amount and sells an identical volume of natural gas at delivery points on its systems at a price that is greater than the purchase price.

Percent-of-Proceeds ("POP"). In exchange for processing services, the Company remits to a producer customer a percentage of the proceeds from sales of residue natural gas and/or NGLs that result from natural gas processing, or in some cases, a percentage of the physical natural gas and/or

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

NGLs at the tailgate of its processing plant, and the Company retains the balance of the proceeds or physical commodity for its own account. On its Gulf Coast System in South Texas, the Company arranges for other parties to process natural gas on its behalf. The most significant of these arrangements is with Formosa Hydrocarbons Company, Inc.("Formosa"), an affiliate of Formosa Plastics Corporation, U.S.A. The Company's processing contract with Formosa entitles it to the greater of (1) a fixed percentage of the value of the NGLs resulting from processing plus 100% of the value of the residue natural gas (an "upgrade" percent-of-proceeds payment) and (2) the value of the unprocessed volume of natural gas priced relative to the same index prices pursuant to which the Company acquired the natural gas (a "floor" percent-of-proceeds payment). The current arrangement with Formosa will expire in January 2013.

Cash and Cash Equivalents Cash and Cash equivalents include all cash balances and investments in highly liquid financial instruments purchased with original maturities of three months or less.

Allowance for Doubtful Accounts In evaluating the realizability of its accounts receivable, the Company performs ongoing credit evaluations of its customers and adjusts payment terms based upon payment history and the customer's current creditworthiness, as determined by the entity's review of the customer's credit information. The Company extends credit on an unsecured basis to many of its customers. As at December 31 2011 and March 31, 2012, the Company recorded no allowance for uncollectable accounts receivable.

Property, Plant and Equipment Property, plant and equipment, consisting primarily of pipelines, processing and treating equipment and facilities, are stated at cost or, upon acquisition of a business at the fair value of the assets acquired.

The Company capitalizes expenditures related to property, plant and equipment that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are replaced, improved, or the useful lives of which have been extended; and (3) all land, regardless of cost. Maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred, except for major overhauls of gas compressors, which are capitalized. Gas required to maintain pipeline minimum pressures ("Line Pack") is capitalized and classified as property, plant and equipment.

Costs related to projects during construction, including interest on funds borrowed to finance the construction of facilities, are capitalized as construction in progress. For the three month period ended March 31, 2011 and 2012, the Company capitalized interest of $32,000 and $1,059,000 respectively. Construction in progress balances are transferred to property, plant and equipment when the assets become ready for their intended use. Depreciation expense is based on cost primarily using the straight line method over the expected useful lives of the related assets. The estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. As circumstances warrant, depreciation estimates are reviewed to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values which would impact future depreciation expense.

The Company had no capital leases as of December 31, 2011 and March 31, 2012.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Rights of Way As part of the Acquisition, the Company assumed certain contractual rights under Right of Way ("ROW") agreements that allow the Company to gain access to and maintain the Company's pipelines and gathering lines in Texas, Mississippi and Alabama which traverse property owned by third parties. The carrying values associated with the ROW recorded in connection with the Acquisition are amortized over their expected useful life of 15 years.

The Company capitalizes costs associated with obtaining ROW to facilitate the building and maintenance of new pipelines and depreciates such costs over the life of the associated pipeline. The ROW agreements require the Company to make periodic (usually annual) payments to property owners, although some are paid several years in advance. Annual ROW payments are expensed when paid, while payments under longer term ROW agreements are amortized over the terms of the agreements.

Intangible Assets The Company has recorded intangible assets at fair value associated with the value of long-term customer contracts. These balances arose from the use of purchase accounting for business combinations as the assets were adjusted to fair market value. These intangible assets are being amortized over their expected useful lives.

Environmental Matters The operations of the Company are subject to various federal, state and local laws and regulations relating to protection of the environment. Although the Company believes that it is in compliance with applicable environmental regulations, risk of costs and liabilities are inherent in pipeline ownership and operation, and there can be no assurances that significant costs and liabilities will not be incurred by the Company. Management is not aware of any contingent liabilities that currently exist with respect to environmental matters.

Asset Retirement Obligations The Company evaluates whether any future asset retirement obligation exist and estimates these costs for some future event. The Company did not provide any asset retirement obligations as of December 31, 2011 and March 31, 2011 because it does not have sufficient information to reasonably estimate such obligations due in part to the fact that the Company has no intention of discontinuing the use of any significant assets or does not have a legal obligation to do so.

Income Taxes Provision for income taxes is attributable to the Company's state tax obligations under the gross margin tax enacted by the State of Texas.

The Company is structured as a partnership for federal income tax purposes and is not subject to federal income taxes. As a result, the owners are individually responsible for paying federal income taxes on their share of the taxable income. The Company follows the guidance for uncertainties in income taxes pursuant to which a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the more-likely-than-not criteria. The Company has not recorded any uncertain tax positions meeting the more-likely-than-not criteria as of December 31, 2011 and March 31, 2012.

Financial Instruments and Derivative Financial Instruments The accounting guidance related to derivative instruments and hedging activities requires the recognition of derivatives in the balance sheet and the measurement of those instruments at fair value. The Company's financial instruments include

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

cash and cash equivalents, accounts receivable, accounts payable, fixed rate debt, variable rate debt, interest rate derivatives and swap contracts based upon natural gas price indices. The Company does not hold or issue financial instruments or derivative financial instruments for trading purposes.

Commodity Risk Management

In its normal course of business, the Company enters into month-ahead swap contracts in order to economically hedge its exposure to certain intra-month natural gas index pricing risk. The Company does not designate these contracts as accounting hedges and records the unrealized and realized gains and losses on the month-ahead swap contract as revenues in the statement of operations.

Interest Rate Risk Management

The Company used an interest rate cap contract that set an upper limit on the 30 day LIBO base rate that the Company would have to pay under the existing credit facility. The Company did not elect hedge accounting for this interest rate cap contract and so changes in market value on this derivative was included in interest expense in the statement of operations. The Company currently has an interest rate swap to partially reduce risks related to floating financing agreements that are subject to changes in the market rate of interest. Terms of the interest rate swap contract require the Company to receive a variable interest rate and pay a fixed interest rate. The Company's interest rate cap agreement are based upon the 30 day LIBO rate. The company has designated the interest rate swap as cash flow hedge. To the extent that the interest rate swap designated as a cash flow hedge is effective, unrealized gains and losses will be recorded in accumulated other comprehensive income and will be transferred to income as the underlying hedged transactions (interest payments) are recorded. Any ineffectiveness will be recorded in interest expense immediately.

The Company measures the derivatives at fair value on a recurring basis using the best information and techniques available, which are primarily Level 2 inputs as defined in the fair value hierarchy. The Company does not have any financial instruments recorded using Level 3 inputs.

Operational Balancing Agreements and Natural Gas Imbalances To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of natural gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than that scheduled, a natural gas imbalance is created. The imbalance is settled through periodic cash payments or re-paid in-kind through future receipt or delivery of natural gas. Natural gas imbalances are classified as other current assets or other current liabilities on our balance sheet based on the market value.

Impairment of Long-Lived Assets The Company reviews its long-lived assets whenever events or circumstances such as economic obsolescence, business climate, legal and other factors indicate that the entity may not recover the carrying value of the assets. The Company continually monitors its business, the market and economic environment to identify indicators that could suggest the carrying value of an asset may not be recoverable. The carrying value of such assets is deemed to be impaired if the projected undiscounted cash flows are less than the carrying value. If there is such impairment, a loss

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

would be recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows, supported by available market valuations, if applicable. No impairment charges were recorded as of March 31, 2011 or March 31, 2012.

Debt Issuance Costs Costs incurred in connection with the issuance of long term debt are deferred and charged to interest expense over the term of the related debt.

Comprehensive Income

For the three months ended March, 31 2011 and 2012, comprehensive income and net income are the same.

Earnings Per Unit The Company has included a calculation of basic and diluted earnings per unit for both periods. The Company calculates the basic earnings per unit by first deducting the amount of cumulative returns on the Redeeemable Preferred and Preferred units from net income, dividing this amount by the weighted average number of vested units (including both the vested Class A common units and vested Class B units). For the calculation of diluted earnings per unit, the unvested units have been included in the computation. The weighted average of unvested units that were included in the computation of diluted earnings per unit for the three months ending March 31, 2011 and the three months ended March 31, 2012 were 263,925 units and 237,409 units, respectively.

Accounting Pronouncements Recently Adopted Accounting standard-setting organizations frequently issue new or revised accounting rules. The Company regularly reviews all new pronouncements to determine their impact, if any, on the financial statements. As of the date of these financial statements, there were no new pronouncements that are expected to materially impact the financial statements.

3. ACQUISITION OF EAI

The Company completed the acquisition of EAI from Enterprise GTM Holdings L.P. for $21.8 million, effective September 1, 2011. EAI owns approximately 388 miles of 2-inch to 16-inch natural gas pipeline assets located in northwest and central Alabama, provides gathering, transportation and compression services and engages in the purchase and sales of natural gas. The Company's identifiable assets acquired and liabilities assumed were recorded based upon the fair values determined on the date of acquisition.

The fair values of property, plant and equipment were determined based upon assumptions related to expected future cash flows, discount rates, and asset lives using currently available information. The Company utilized a mix of the cost, income and market approaches in determining the estimated fair values of such assets. The fair value measurements and models are classified as non-recurring level 3 measurements consistent with accounting standards related to the determination of fair value. The Company has completed the final purchase price allocation to the assets acquired and liabilities assumed as of March 31, 2012.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

3. ACQUISITION OF EAI (Continued)

Identified assets acquired and liabilities assumed are as follows (dollars in thousands):

Current assets	$	3,374
Property, plant, and equipment		19,300
Intangible assets		1,700
Total assets acquired		24,374
Current liabilities		2,597
Total liabilities assumed		2,597
Net identifiable assets acquired	$	21,777

The Company attributed $1.7 million to the value of long term contracts assumed in the acquisition, the majority being for life of lease which has been determined to be thirty years or the expected life of the pipelines. The Company determined that the purchase price was equal to the fair value of net assets acquired, thus no goodwill was recorded.

The Company expensed $0.2 million of transaction costs associated with the acquisition of EAI. These costs were incurred in the second half of 2011 and reported within transaction costs.

Unaudited Pro Forma Financial information The following unaudited pro forma financial information assumes that the EAI acquisition occurred on January 1, 2011. The unaudited pro forma information is not necessarily indicative of what Southcross Energy LLC's financial position or results of operation would have been if the transaction had occurred on this date, or what Southcross Energy LLC's financial position or results from operations will be for any future periods.

	Three months ended March 31, 2011 (in thousands)(1)	
Revenue	$	133,079
Net Income	$	1,171

(1) Pro forma adjustments for the three months ended March 31, 2011 consist of adjustments for income from operations, including depreciation and amortization as well as the effects of financing the acquisition.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

4. PROPERTY, PLANT, AND EQUIPMENT

		Southcross Energy LLC	
	Estimated Useful Life	December 31, 2011	March 31, 2012
		(in thousands)	
Pipeline	30	$ 230,866	$ 231,151
Treating plants	15	5,294	5,294
Gas processing plants	15	31,696	34,451
Rights of way	15	20,249	20,249
Compressors	7	16,078	16,171
Furniture, fixtures & equipment	5	2,814	2,868
Line pack		1,083	1,083
Land and easements		3,139	3,139
Construction in progress		86,189	128,616
Total property, plant and equipment		397,408	443,022
Accumulated depreciation and amortization		(27,547)	(31,197)
Net property, plant and equipment		$ 369,861	$ 411,825

Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as shown in the above table.

5. INTANGIBLE AND OTHER ASSETS

Intangible assets represent the value assigned to purchase long-term supply contracts, which are amortized on a straight line basis over the expected life of the contracts. We have amortized $14,000 for the three months ended March 31, 2012, which is reported within depreciation and amortization expense.

In conjunction with the financings obtained from the syndicate of lenders led by Wells Fargo Bank, N.A. we have incurred certain costs and fees which we have been capitalized as deferred financing costs and have amortized these financing costs over the term of the applicable loan. As of December 31, 2011, the outstanding balance of deferred financing costs including balances remaining from previous financings was $2.2 million and was being amortized to interest expense over the term of the Amended and Restated Credit Agreement through June 30, 2016.

As a result of our entering into the First Amendment of the Amended and Restated Credit Agreement ("Amended and Restated Credit Agreement") with a syndicate of lenders led by Wells Fargo Bank, N.A., on February 7, 2012 which was not accounted for as an extinguishment of debt, we incurred $2.3 million in costs. These deferred financing costs, along with existing unamortized deferred costs will be amortized over the remaining life of this agreement.

The net carrying amount of deferred financing costs is included in the balance sheet in other assets and was $4.2 million as of March 31, 2012. The Company recognized deferred financing cost amortization for the three months ending March 31, 2011 and 2012 of $0.3 million and $0.3 million, respectively.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

6. MEMBERS' EQUITY

As of December 31, 2011, the Company's common equity was comprised of 1,415,729 Class A common units of which 217,483 were unvested, and 57,279 Class B units of which 34,367 were unvested. The Class B units have the same distribution and liquidation rights as the Class A common units, however they do not have voting rights. All Class A common and Class B units were purchased for, and have a par value of, $1.00 per unit.

Prior to March 20, 2012, incentive units were held by certain members of management through Estrella Energy LP, which was partially owned by a non-management third party . On March 20, 20112, Estrella Energy LP was dissolved and the units distributed to the non-management third party were repurchased and retired for $15.3 million. As of March 31, 2012, the Company's common equity is comprised of 1,313,445 Class A common units of which 115,199 were unvested, and 28,639 Class B units of which 17,184 were unvested.

On August 6, 2009, an officer of the Company borrowed $150,000 from the Company to fund the acquisition of units of preferred and common equity of the Company pursuant to the terms and conditions of a promissory note executed between the officer and the Company. The officer paid $37,500 on August 6, 2010 and $112,500 on July 28, 2011. The net balance, as of December 31, 2011 was $26,000 which represents the unpaid interest outstanding on the note and was paid in full on March 16, 2012.

As of March 31, 2012, the Company does not have any long-term incentive plans or shares authorized for issuance of share-based compensation.

As noted above, in connection with the Acquisition, five individuals comprising of our management team were allowed to purchase, individually or indirectly through Estrella Energy, LP, Class A common units and Class B units along with our sponsor for the same value as our sponsor ($1.00 per unit). Certain of the Class A common units and all of the Class B units contain time- and performance-vesting conditions. Time vesting units vest ratably over five years subject to certain accelerated vesting based primarily on a change in control or certain termination causes. Performance-vesting units will vest, if at all, upon Charlesbank attaining certain investment multiples and internal rates of return t in connection with a liquidity event. Both the time- and performance-vesting units require continued employment through any vesting date.

No compensation expense has been recorded for the time-based vesting units as the price paid by the individuals was equal to the fair value of the units on the date purchased. No compensation expense has been recorded for the performance-based vesting units as the price paid for the units was equal to the fair value of the units on the date purchased. Upon an employee's termination of employment, any unvested incentive units are subject to the company's right, but not obligation, to repurchase such units at the employee's initial acquisition cost (or less in certain circumstances).

Prior to March 20, 2012, incentive units were held by certain members of management through Estrella Energy LP, which was partially owned by a non-management third party. On March 20, 2012, Estrella Energy LP was dissolved and the units distributed to the non-management third party were repurchased and retired by the Company. Management did not receive any consideration in connection

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

ENDED MARCH 31, 2011 AND MARCH 31, 2012

6. MEMBERS' EQUITY (Continued)

with such repurchases. The following table provides information regarding the outstanding incentive units held by management as of March 31, 2012.

	Number of units purchased Subject to		Number of units vested Subject to	
	time vesting	**performance**	**time vesting**	**performance**
Class A	3,096	113,342	1,239	
Class B	28,639		11,456	

7. PREFERRED UNITS

Preferred Units

As of March 31, 2012 and December 31, 2011, the Company's cumulative preferred comprised of 11,850,374 units with a par value of $10 per unit, which accrue value (in the form of an additional preferential right to receive distributions) at a rate of 10% per annum, compounded quarterly.

Except in the case of cash distributions made for the purpose of paying federal income taxes, which are made to both preferred and common equity owners in direct proportion to the owners' respective share of taxable income, owners of the preferred equity receive cash distributions before owners of common equity. The preferred units and their cumulative return are subordinate to all redeemable preferred units and their cumulative return discussed below. As discussed within Note 8 and with the exception of cash distributions for federal income tax purposes, the Company's credit agreement includes certain covenants that restrict its ability to pay cash dividends to its owners. The Company adjusts the carrying value of the cumulative right to receive distributions on a quarterly basis. As of December 31, 2011 and March 31, 2012, the preferred units' cumulative right to receive future cash distributions was $31.8 million and $35.5 million, respectively, as a result of the cumulative preferred return on such units.

Redeemable Preferred Units

On June 10, 2011, in conjunction with the Company entering into an Amended and Restated Credit Agreement with our lenders, Charlesbank and most of our existing investors contributed a total of $15.0 million in exchange for 1,500,000 Redeemable Preferred Units. The Redeemable Preferred Units have a par value of $10 per unit and accrue value (in the form of an additional preferential right to receive distributions) at a rate of 18% per annum, compounded quarterly. These units are redeemable by us in whole or in part at any time, or shall be redeemed by us promptly after our satisfaction of all obligations under the Amended and Restated Credit Agreement. The Company adjusts the carrying value of the redeemable preferred units to reflect the cumulative right to receive distributions on a quarterly basis. As of December 31, 2011 and March 31, 2012, the redeemable preferred's right to receive future cash distributions included an additional $1.6 million and $2.3 million, respectively, as a result of the cumulative preferred return on such units. The Redeemable Preferred units and their cumulative return are sub-ordinated to the Series B Redeemable Preferred units and their cumulative return. Both Redeemable Preferred units and their cumulative return are senior to the Preferred Units. On March 20, 2012, Charlesbank contributed $25.3 million in cash and

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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ENDED MARCH 31, 2011 AND MARCH 31, 2012

7. PREFERRED UNITS (Continued)

an affiliate of Wells Fargo Securities, LLC contributed $10.0 million in cash to the Company in exchange for 2.53 million units and 1.0 million units, respectively, of a new class, Series B, of Redeemable Preferred Units. As of March 31, 2012, the Company's Series B Redeemable Preferred Units comprised of 3,530,000 units with a par value of $10.00 per unit, which accrue value (in the form of an additional preferential right to receive distributions) at a rate of 18% per annum, compounded quarterly. These units are redeemable by the Company in whole or in part at any time, or shall be redeemed by the Company promptly after the satisfaction by the Company of all its obligations under the Amended and Restated Credit Agreement. As of March 31, 2012, the Series B redeemable preferred's right to receive future cash distributions was $0.2 million as a result of the cumulative preferred return on such units.

8. LONG TERM DEBT

For the three months ended March 31, 2011, the Company had weighted average borrowings outstanding of $114.6 million at the effective average interest rate of 3.56%. For the three months ended March 31, 2012, the Company had weighted average borrowings of $227.0 million at the effective average interest rate of 3.63%. As of March 31, 2012, the Company had an outstanding term loan of $158.9 million with a LIBO interest rate of 3.25% and two revolver loans, one of $66.5 million with a LIBO interest rate of 3.25% and the other of $12.0 million with an ABR interest rate of 5.25%. As of March 31, 2012, the Company is compliance with all loan covenants.

Amendment to the Original Credit Agreement December 30, 2010

On December 30, 2010, the Company entered into the First Amendment of the Credit Agreement, which extended the maturities of our debt from August 6, 2012 to June 30, 2014 and lowered the applicable interest rate margins. The terms of the amended credit agreement increased the term loan borrowings limit to $115 million. Per the terms of the amended credit agreement, quarterly scheduled principal payments were reduced to $2.875 million commencing on March 31, 2011 with the remaining balance maturing on June 30, 2014. In addition, the amended credit agreement increased the limit on the use of the revolver on LCs to no more than $30 million and provided for the ability to expand the revolver to $55 million upon request by the Company.

Per the amended credit agreement of December 30, 2010, through loan maturity of June 30, 2014, the applicable margins, excess cash prepayment percentages, and LC fee percentages are presented in the following table.

Leverage Ratio	LIBO Loan Margin	ABR Loan Margin	Excess Cash Prepayment	LC Fees
Above 3.5x	3.25%	2.25%	50%	3.25%
From 3.0x to 3.5x	3.00	2.00	50	3.00
From 2.5x to 3.0x	2.75	1.75		2.75
From 2.0x to 2.5x	2.50	1.50		2.50
Below 2.0x	2.50	1.50		2.50

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

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ENDED MARCH 31, 2011 AND MARCH 31, 2012

8. LONG TERM DEBT (Continued)

As of December 31, 2010, the loans outstanding for the First Amendment of the Credit Agreement were an ABR loan of $14,195,000 that bore interest at an effective rate of 5.5% and a LIBO loan of $100,805,000 that bore interest at an effective interest rate of 3.52%.

Amended and Restated Agreement to the Original Credit Agreement June 10, 2011

On June 10, 2011, the Company entered into the Amended and Restated Credit Agreement with a maturity of June 10, 2016. The Company accounted for the Amended and Restated Credit Agreement as an extinguishment of debt, and accordingly recognized a loss on extinguishment of debt in the second quarter of 2011. The Company's term loan commitment increased from $115 million to $153 million in connection with the Amended and Restated Credit Agreement, and the Company received net proceeds of $30 million. The Amended and Restated Credit Agreement also gave the Company the right to draw down an additional term loan amount not to exceed $22.0 million by September 30, 2011, and on August 30, 2011, the Company borrowed an additional $21.9 million to fund the acquisition of EAI. This agreement also provides the Company with a current Revolving loan capacity of $150.0 million which includes a sub-limit of up to $50.0 million for LCs. This Revolving loan capacity may be increased to $185.0 million by request of the Company subject to certain conditions. The Company used $120.7 million to pay off the existing loans, plus accrued interest, under the Credit Agreement. Per the terms of the Amended and Restated Credit Agreement, the Company made a payment of $2.9 million on June 30, 2011 and thereafter quarterly scheduled principal payments are $4.4 million commencing on September 30, 2011, with the remaining balance maturing on June 10, 2016.

As of December 31, 2011, the Company had an outstanding term loan of $163.3 million with a LIBO interest rate of 3.58% and a revolver loan of $45.0 million with an interest rate of 3.67%. As of December 31, 2011, the Company was in compliance with all loan covenants.

Interest rates applied to the outstanding balance of the loan are tied to either one-month, three-month, or six-month LIBO rates plus a margin which also fluctuates in relation to the Leverage Ratio or an ABR selected at the Company's option, plus a margin which also fluctuates in relation to the Leverage Ratio. Alternate Base Rate (ABR) loan rates include the applicable margin plus the greatest of (a) the prime rate in effect at the principal offices of the lead lender (b) the Federal Funds Rate plus 0.5%, and (c) one-month LIBO rates plus 1.0%.

Per the Amended and Restated Credit Agreement, through loan maturity of June 10, 2016, the applicable margins for apply to both term and revolver borrowings, and LC fee percentages are presented in the following table:

Leverage Ratio	LIBO Loan Margin	ABR Loan Margin	LC Fees
Above 4.5x	3.25%	2.25%	3.25%
From 4.0x to 4.5x	3.00	2.00	3.00
From 3.5x to 4.0x	2.75	1.75	2.75
From 3.0x to 3.5x	2.50	1.50	2.50
Below 3.0x	2.25	1.25	2.25

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8. LONG TERM DEBT (Continued)

All the Company's property, including all of its ownership interests in its subsidiaries, is pledged or was pledged as collateral under the Company's credit agreements listed above. The terms of the credit facilities contain customary covenants, including those that restrict the Company's ability to make or limit certain payments, distributions, acquisitions, loans, or investments, incur certain indebtedness or create certain liens on its assets, consolidate or enter into mergers, dispose of certain of the Company's assets, engage in certain types of transactions with its affiliates, enter into certain sale/leaseback transactions and modify certain material agreements.

The events that constitute default under all of the credit facilities include, among other things, the failure to pay principal and interest on the indebtedness under the facilities when due, failure to comply with certain covenants or breach representations and warranties made under the credit facilities, certain bankruptcy, dissolution, liquidation or other insolvency events, occurrence of a material adverse change or a change of control.

Amendment to the Amended and Restated Agreement Credit Agreement February 7, 2012

On February 7, 2012, the Company entered into the First Amendment of the existing Amended and Restated Credit Agreement. The amendment has been accounted for as a modification of an existing debt agreement. This amendment was made to increase the Company's loan capability in order to satisfy the Company's operations and capital plans. The Company obtained modifications to the covenants to reflect the need for capital expansion to support its growth plans. This amendment did not change the term loan and revolver loan capacity; it did modify pricing on the higher permitted leverage ratio as shown on the following table which has a new tier pricing for when the leverage ratio is greater than 5.0 times.

Leverage Ratio	LIBO Loan Margin	ABR Loan Margin	LC Fees
Above 5.0x	4.25%	3.25%	4.25%
From 4. 5x to 5.0x	3.25	2.25	3.25
From 4.0x to 4.5x	3.00	2.00	3.00
From 3.5x to 4.0x	2.75	1.75	2.75
From 3.0x to 3.5x	2.50	1.50	2.50
Below 3.0x	2.25	1.25	2.25

The Company incurred $2.3 million in fees and expenses related to this First Amendment of the which have been accounted for as deferred financing fees and will be amortized over the remaining life of this agreement.

Under the terms of this Amendment, the Company was required to obtain an additional capital injection of $20.0 million by March 31, 2012; this requirement was met by the receipt of funds from Charlesbank and Wells Fargo on March 20, 2012 and the issuance of Series B Redeemable Preferred Units. In addition, the Company is also required to obtain an additional $7.5 million of capital funding by June 30, 2012 which the Company anticipates receiving from Charlesbank. There are also covenant restrictions with regard to certain growth capital expenditures for which the Company will be able to remain in compliance for the foreseeable future.

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ENDED MARCH 31, 2011 AND MARCH 31, 2012

8. LONG TERM DEBT (Continued)

As of March 31, 2012, the Company had an outstanding term loan of $158.9 million with a LIBO interest rate of 3.25% and a revolver loan of $78.5 million with an effective interest rate of 3.56% . As of March 31, 2012, the Company is compliance with all loan covenants.

9. CONCENTRATION OF CREDIT RISK AND TRADE ACCOUNTS RECEIVABLE

The Company's primary markets are in Texas, Alabama and Mississippi. The Company has a concentration of trade accounts receivables due from customers engaged in the production, trading, distribution and marketing of natural gas and NGL products. These concentrations of customers may affect our overall credit risk in that these customers may be similarly affected by changes in economic, regulatory or other factors. The Company analyzes the customers' historical financial and operational information prior to extending credit.

Formosa Hydrocarbons Co, Inc and Sherwin Alumina Company are significant customers, each representing at least 10% of our consolidated revenue, each individually accounting for $22.4 million and $20.2 million, respectively, of our consolidated revenue for the three month period ended March 31, 2011 and $36.6 million and $11.7 million, respectively, for the three month period ended March 31, 2012. Our top ten customers represent 73.2% of our consolidated revenue for the three month period ended March 31, 2011 and 73.5% of our consolidated revenue for the three month period ended March 31, 2012.

10. COMMITMENTS AND CONTINGENCIES

Leases

The Company has a non-cancelable lease for its office facilities in Dallas, Texas which expires August 16, 2016. Rent expense was $59,000 and $77,000 for the three months ended March 31, 2011 and March 31, 2012, respectively.

Litigation

The Company is from time to time subject to claims and suits arising in the ordinary course of business, including those relating to contractual obligations. The Company accrues for potential liabilities involved in these matters as they become probable and can be reasonably estimated. The Company was not involved in any significant claims or litigation for the three month period ended March 31, 2012, and had no litigation accrual as of December 31, 2011 or March 31, 2012.

Outstanding commitments on our expansion projects

The Company has initiated plans to expand its capabilities. During 2011, the Company placed purchase orders to start the construction of a new 200 MMcf/d Woodsboro processing plant in Refugio County, Texas which has an estimated total cost of $97.0 million and is expected to come on line in June 2012. In addition, during November 2011, the Company finalized the acquisition of an existing fractionating facility and entered into contracts to refurbish and install this equipment at its Bonnie

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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10. COMMITMENTS AND CONTINGENCIES (Continued)

View fractionation site. The total estimated cost for this project is $32.0 million. As of March 31, 2012, the Company has $24.5 million in firm commitments outstanding for major projects.

11. DEFINED CONTRIBUTION PLANS

The Company established a defined contribution pension plan for its employees in 2009 in which virtually all employees are eligible to participate. The Company's contributions and expense to this plan, which are based upon the employees' contributions to the plan, were approximately $114,000 and $156,000 for the three month period ended March 31, 2011 and March 31, 2012, respectively and has been reported within operations and maintenance or general and administrative expense depending upon the employee's position.

12. RELATED PARTY TRANSACTIONS

Charlesbank provides certain management services to the Company under the terms of an agreement with the Company which requires an annual management fee of $600,000. The Company has expensed $150,000 for such services for both the three month period ending March 31, 2011 and 2012, which are reported within general and administrative expenses.

The Company entered into the credit agreements with syndicates of financial institutions and other lenders. These syndicates included affiliates of Wells Fargo Bank, N.A., which is a member of the investor group. See Note 8 of the Notes to Consolidated Financial Statements. Affiliates of Wells Fargo Bank, N.A. have from time to time engaged in commercial banking and financial advisory transactions with the Company in the normal course of business including the interest rate swap contract that we entered into on March 2, 2012.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

Accounting standards related to the determination of fair value define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company uses the market approach for recurring fair value measurements and to maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company categorizes the assets or liabilities recorded at fair value based upon the following fair value hierarchy:

Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. An active market is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 valuations use inputs, in the absence of actively quoted market prices, that are observable for the asset or liability, either directly or indirectly. Level 2 inputs include: (a) quoted prices for similar assets or liabilities in active markets, (b) quoted prices for identical or similar assets or liabilities in markets that are not active, (c) inputs other than quoted prices

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DECEMBER 31, 2011 AND MARCH 31, 2012 AND THE THREE MONTHS

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13. FAIR VALUE OF FINANCIAL INSTRUMENTS (Continued)

that are observable for the asset or liability such as interest rates and yield curves observable at commonly quoted intervals and (d) inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 valuations use unobservable inputs for the asset or liability. Unobservable inputs are used to the extent observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. The Company uses the most meaningful information available from the market combined with internally developed valuation methodologies to develop the best estimate of fair value.

The carrying amount reported in the balance sheets for cash and cash equivalents, trade accounts receivable and trade accounts payable approximates its fair value due to the short maturity of these instruments.

The Company determined that the fair value of debt as of December 31, 2011 and March 31, 2012 approximated book value due to the fact that the Amended and Restated Credit Agreement was entered into on June 10, 2011 and amended on February 7, 2012 and that there has been no significant change in market conditions or our credit rating or pricing since that time.

With regard to month-ahead swap contracts, the Company has utilized publicly available pricing of commodities to determine the fair value of these contracts. The Company defines these contracts as Level 2, as the index prices associated with such contracts is observable, and tied to the quoted first of the month natural gas index price. Based on the short term nature of the contracts and immaterial notional amounts, these contracts are not material.

	Fair value measurement as of	
	December 31, 2011	**March 31, 2012**
Description	**Significant Other Observable Inputs (Level 2)**	
	(in thousands)	
Interest rate cap liability	$ 21	$
Interest rate swap liability		243

14. DERIVATIVES

In its normal course of business, the Company enters into month-ahead swap contracts in order to economically hedge its exposure to certain intra-month natural gas index pricing risk. The total volume of month-ahead swap contracts outstanding as of December 31, 2011 and March 31, 2012, was 372,000 MMBtu and zero respectively.

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14. DERIVATIVES (Continued)

The realized gains on these derivatives in the condensed consolidated statements of operations, reported within Revenues, are as follows:

	Southcross Energy LLC	
	Three months ended March 31, 2011	Three months ended March 31, 2012
	(in thousands)	
Realized (gain) on derivatives	$ (96)	$ (7)

On February 17, 2011, the Company entered into an interest rate cap contract with Wells Fargo, N.A., effective March 31, 2011 for $80.0 million notional amount of debt. The contract effectively capped the Company's US Dollar LIBO based interest rate exposure on that portion of our debt on a sliding scale, that started at 1.51% as of March 31, 2011 and increased to 4.57% at the end of the contract on June 30, 2014. The notional amount of debt declined over time so that the amount of debt covered by this contract was $65.0 million, $43.0 million and $23.0 million at December 31, 2011, 2012 and 2013 respectively. The Company defined this contract as Level 2. The unrealized and realized gains and losses were recorded in interest expense. The Company did not designated the interest rate cap as a hedging instrument for accounting purposes; therefore it wasaccounted for at fair value in the condensed consolidated statement of operations as follows:

	Southcross Energy LLC	
	Three months ended March 31, 2011	Three months ended March 31, 2012
	(in thousands)	
Unrealized loss on interest rate cap / swap	$ 186	$ 222

This contract was terminated on March 2, 2012, and the Company entered into an interest rate swap contract effective March 30, 2012 with the notional value of $150 million and maturity of June 30, 2014. Under the terms of this contract, the Company has fixed the LIBO base rate for borrowings at 0.54%. The Company designated the interest rate swap as a cash flow hedge at March 30, 2012.

15. PHANTOM UNITS

The Company has provided to certain key non-officer employees equity incentive units ("Phantom Units") in the Company. The Phantom Units vest upon the occurrence of a change in control where more than 50% of the voting power of the Company changes hands, or upon the occurrence of a liquidity event where, through the sale of some portion of its ownership, the majority owner of the Company achieves or exceeds a targeted rate of return on its original investment. The number of Phantom Units earned and eligible for vesting increase over a period of years or through the achievement of certain rates of return by the majority owner of the Company, or a combination thereof. As of December 31, 2011 and March 31, 2012, no fair value was attributable to the Phantom Units and no compensation expense associated with these units was recorded during the three months ended March 31, 2011 and March 31, 2012. As of December 31, 2011 and March 31, 2012, the number of authorized and issued Phantom Units was 10,832.

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16. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

The following tables discloses certain cash payments for interest and taxes and the value of capital expenditures remaining in accounts payable (in thousands).

	Southcross Energy LLC	
	Three Months Ended March 31, 2011	Three Months Ended March 31, 2012
Cash paid for interest	$ 2,730	$ 2,331
Cash paid for taxes	(1)	

	As of March 31, 2011	As of March 31, 2012
Capital expenditure remaining in accounts payable	2,740	17,564

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers of Southcross Energy LLC
Dallas, Texas

We have audited the accompanying consolidated balance sheets of Southcross Energy LLC and subsidiaries (the "Company") as of December 31, 2010 and 2011, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for the period from June 2, 2009 (Date of Inception) to December 31, 2009, and the years ended December 31, 2010 and December 31, 2011 (Successor Period). We have also audited the accompanying combined statements of operations, comprehensive income, equity, and cash flows for the period from January 1, 2009 to July 31, 2009 (Predecessor Period) for the Southcross Energy Predecessor. These financial statements are the responsibility of the Company'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 Company 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 Company'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 financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2010 and 2011, and the results of their operations and their cash flows for the period from June 2, 2009 (Date of Inception) to December 31, 2009 and the years ended December 31, 2010 and December 31, 2011, and the results of Southcross Energy Predecessor's operations and cash flows for the period from January 1, 2009 to July 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the Financial Statements, Southcross Energy LLC acquired certain entities and assets from Crosstex Energy, L.P. effective August 1, 2009.

/s/ Deloitte & Touche LLP

Dallas, Texas
April 20, 2012

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF DECEMBER 31, 2010 AND 2011 (SUCCESSOR PERIOD)

(Dollars in thousands)

	Southcross Energy LLC	
	2010	**2011**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 20,323	$ 1,412
Trade accounts receivable	35,059	41,234
Prepaid expenses	609	950
Other current assets	399	561
Total current assets	56,390	44,157
PROPERTY, PLANT, AND EQUIPMENT Net	229,309	369,861
INTANGIBLE ASSET		1,681
OTHER ASSETS	3,944	4,686
TOTAL	$ 289,643	$ 420,385
LIABILITIES, PREFERRED UNITS AND MEMBERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 35,097	$ 50,439
Interest payable	1,779	24
Current maturities of long term debt	11,500	17,490
Other current liabilities	3,782	4,983
Total current liabilities	52,158	72,936
LONG TERM DEBT	103,500	190,790
DERIVATIVE LIABILITY		21
Total liabilities	155,658	263,747
COMMITMENTS AND CONTINGENCIES (Note 10)		
REDEEMABLE PREFERRED UNITS		16,554
PREFERRED UNITS	136,006	150,249
MEMBERS' EQUITY		
Common equity Class A (1,415,729 common units authorized and outstanding as of December 31, 2010 and December 31, 2011)	1,415	1,416
Common equity Class B (57,279 units authorized and outstanding as of December 31, 2010 and December 31, 2011)	57	57
Accumulated deficit	(3,493)	(11,638)
Total members' equity	(2,021)	(10,165)
TOTAL LIABILITIES, PREFERRED UNITS AND MEMBERS' EQUITY	$ 289,643	$ 420,385

See accompanying notes to the financial statements.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

STATEMENTS OF OPERATIONS

FOR THE PERIOD JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD) AND FOR THE PERIOD JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009, AND THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

(Dollars in thousands, except for per unit data)

	Southcross Energy Predecessor	Southcross Energy LLC		
	January 1, 2009 to July 31, 2009	June 2, 2009 (Date of Inception) to December 31, 2009	December 31, 2010	December 31, 2011
TOTAL REVENUE	$ 330,870	$ 206,634	$ 498,747	$ 523,149
EXPENSES:				
Cost of natural gas and liquids sold	301,368	179,045	439,431	460,580
Operations and maintenance	10,648	7,847	21,106	24,707
Depreciation and amortization	7,268	4,235	10,987	12,345
General and administrative	9,788	3,225	7,341	8,926
Transaction costs		2,957	149	203
Total expenses	329,072	197,309	479,014	506,761
INCOME FROM OPERATIONS	1,798	9,325	19,733	16,388
INTEREST INCOME		9	25	24
LOSS ON EXTINGUISHMENT OF DEBT				(3,240)
INTEREST EXPENSE		(4,554)	(10,038)	(5,372)
INCOME BEFORE INCOME TAX EXPENSE	1,798	4,780	9,720	7,800
INCOME TAX EXPENSE	(77)	(372)	(1)	(261)
NET INCOME	1,721	4,408	9,719	7,539
Less: deemed dividend on Redeemable Preferred units				1,553
deemed dividend on Preferred Units		4,818	12,802	14,131
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON UNITHOLDERS	$ 1,721	$ (410)	$ (3,083)	$ (8,145)
Net loss per common unit (basic and diluted)		$ (0.34)	$ (2.57)	$ (6.79)

See accompanying notes to the financial statements.

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STATEMENTS OF COMPREHENSIVE INCOME

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(Dollars in thousands)

	Southcross Energy Predecessor	Southcross Energy LLC		
	Period From January 1, 2009 to July 31, 2009	June 2, 2009 (Date of Inception) to December 31, 2009	December 31, 2010	December 31, 2011
NET INCOME	$ 1,721	$ 4,408	$ 9,719	$ 7,539
REALIZED GAINS ON CASH FLOW HEDGE	823			
ADJUSTMENT IN FAIR VALUE OF DERIVATIVES	(1,354)			
COMPREHENSIVE INCOME	$ 1,190	$ 4,408	$ 9,719	$ 7,539

See accompanying notes to the financial statements.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

STATEMENTS OF EQUITY

**FOR THE PERIOD JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD)
AND FOR THE PERIOD JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009,
AND THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)**

(Dollars in thousands)

	Owner's Equity
Southcross Energy Predecessor	
BALANCE OF OWNER'S EQUITY December 31, 2008	$ 84,005
Conversion of Crosstex Advances to owner's equity	32,519
Net income	1,721
Accumulated other comprehensive income	(531)
BALANCE OF OWNER'S EQUITY July 31, 2009	$ 117,714

	Common Equity	Accumulated Deficit	Total Members' Equity
Southcross Energy LLC and subsidiaries			
BALANCE OF MEMBERS' EQUITY June 2, 2009	$	$	$
Contributed equity	1,471		1,471
Net income		4,408	4,408
Deemed dividend on Preferred Units		(4,818)	(4,818)
BALANCE OF MEMBERS' EQUITY December 31, 2009	1,471	(410)	1,061
Receipt of payment from unit note holder	1		1
Net income		9,719	9,719
Deemed dividend on Preferred Units		(12,802)	(12,802)
BALANCE OF MEMBERS' EQUITY December 31, 2010	1,472	(3,493)	(2,021)
Receipt of payment from unit note holder	1		1
Net income		7,539	7,539
Deemed dividend on Redeemable Preferred Units		(1,553)	(1,553)
Deemed dividend on Preferred Units		(14,131)	(14,131)
BALANCE OF MEMBERS' EQUITY December 31, 2011	$ 1,473	$ (11,638)	$ (10,165)

See accompanying notes to the financial statements.

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STATEMENTS OF CASH FLOWS

FOR THE PERIOD JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), FOR THE PERIOD JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009, AND THE YEAR ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

(Dollars in thousands)

	Predecessor	Southcross Energy LLC		
	January 1, 2009 to July 31, 2009	June 2, 2009 (Date of Inception) to December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011
OPERATING ACTIVITIES:				
Net income	$ 1,721	$ 4,408	$ 9,719	$ 7,539
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation and amortization	7,268	4,235	10,987	12,345
Loss on extinguishment of debt				3,240
Deferred financing fees amortization		897	2,158	882
Gain on sale of plant, property and equipment			(13)	(522)
Unrealized derivatives loss	170			21
Realized gains on cash flow hedges	(823)			
Changes in operating assets and liabilities:				
Accounts receivable	(1,293)	(39,956)	4,897	(2,806)
Accrued sales	32,347			
Prepaid expenses and other	(1,464)	(833)	560	(497)
Other non-current assets		(534)	158	(2,155)
Accounts payable	920	38,933	(3,836)	2,759
Accrued cost of sales	(32,542)			
Interest payable		197	1,582	(1,755)
Accrued expenses and other current liabilities	(2,174)	2,817	(719)	809
Commodity assets and liabilities	825			147
Net cash provided by operating activities	4,955	10,164	25,493	20,007
INVESTING ACTIVITIES:				
Acquisition of EAI				(21,777)
Capital expenditures	(815)	(4,694)	(5,245)	(123,347)
Acquisition of Crosstex assets and SWE		(233,790)		
Sale of property, plant, and equipment	24	145	14	522
Net cash used in investing activities	(791)	(238,339)	(5,231)	(144,602)
FINANCING ACTIVITIES:				
Proceeds from long-term debt		125,000	14,195	174,900
Repayment of long-term debt		(5,051)	(19,144)	(126,619)
Borrowings under revolving credit facility		5,000		54,500
Repayment of revolving credit facility		(5,000)		(9,500)
Financing costs		(5,870)	(752)	(2,710)
Members' contribution for Common Units		1,316		
Proceeds from issuance of Preferred Units		118,504		
Receipt of payment from unit note holder			38	113
Proceeds from issuance of Redeemable Preferred Units				15,000
Advances to Predecessor's former owner	(4,164)			
Net cash provided by (used in) financing activities	(4,164)	233,899	(5,663)	105,684

INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS			5,724	14,599	(18,911)
CASH AND CASH EQUIVALENTS Beginning of period				5,724	20,323
CASH AND CASH EQUIVALENTS End of period	$	$	5,724	$ 20,323	$ 1,412

See accompanying notes to the financial statements.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

1. ORGANIZATION AND PRESENTATION

Organization Southcross Energy LLC (a Delaware limited liability company) and subsidiaries (collectively, the "Company") was formed on June 2, 2009 (the "Inception Date"). The Company's principal operations commenced with the acquisition of certain entities and assets (the "Predecessor" or "Southcross Energy Predecessor") from Crosstex Energy, L.P. ("Crosstex") on August 6, 2009 (effective August 1, 2009) (the "Acquisition").

The Company is a midstream pipeline company that provides natural gas gathering, processing, treating, compression and transportation services and natural gas liquid ("NGL") fractionation services to its producer customers, and also sources, purchases, transports and sells natural gas and NGLs to its power generation, industrial and utility customers. The Company's assets are located in South Texas, Mississippi and Alabama. Effective September 1, 2011, the Company completed the acquisition of Enterprise Alabama Intrastate, LLC ("EAI") for $21.8 million. This acquisition added significant scale to the Company's existing network and capability in Alabama. The Company is controlled through investment funds and entities associated with Charlesbank Capital Partners, LLC ("Charlesbank").

Basis of Presentation and Principles of Consolidation or Combination The Company has prepared the financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The accompanying consolidated financial statements include the accounts of Southcross Energy LLC and its controlled subsidiaries. All of the Company's subsidiaries are wholly owned, either directly or indirectly through wholly owned subsidiaries. All inter-company accounts and transactions have been eliminated in the preparation of the accompanying financial statements.

The consolidated financial statements present the activities of the Company from the Inception Date, through December 31, 2011 (Successor period), including its acquired subsidiaries and assets from Crosstex from August 1, 2009 through December 31, 2011. Between the Inception Date and the effective date of the Acquisition, discussed in Note 3, operations of the Company consisted only of an insignificant amount of start-up activities and general and administrative ("G&A") expenses.

The combined statements of operations, cash flows, and changes in owner's equity for the period January 1, 2009 to July 31, 2009 (Predecessor period), have been prepared on the basis of Crosstex's historical ownership of the Predecessor. All inter-company accounts and transactions have been eliminated in the preparation of the accompanying combined financial statements. These combined financial statements represent the results of operations, changes in owner's equity and cash flows of the acquired entities, and have been carved out of the accounting records maintained by Crosstex and its subsidiaries. The Company estimated G&A expenses as Crosstex did not allocate any of its central finance and administrative costs to its operating entities. The Company has based this estimate of G&A expense for the Predecessor on an allocation of Crosstex's total G&A expenses based upon the Predecessor's revenue as a percentage of Crosstex's total revenue for each period. Because of the nature of these carved-out combined financial statements, the intercompany advances to and from Crosstex were reported within an intercompany advances account, and immediately prior to the acquisition were converted to owner's equity. The intercompany advances to and from Crosstex did not bear interest. The average balance due to Crosstex was $34.6 million for the seven month period ended

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

1. ORGANIZATION AND PRESENTATION (Continued)

July 31, 2009. The outstanding debt obligations of Crosstex were not specifically related to the operations of the Predecessor, and were not recorded on the general ledger of the Predecessor entities. Therefore, no outstanding debt obligations or interest expense, including intercompany interest expense, has been allocated to the Predecessor.

Management of the Company believes that the assumptions and estimates used in preparation of the combined statements, including the allocation of G&A expenses, are reasonable. However, the combined financial statements may not necessarily reflect what the Predecessor's results of operations or cash flows would have been had it been a stand-alone entity during the period presented.

The Company reports its operations under one reportable segment. There are three integral elements to the Company's total pipeline network. First, the Company collects gas from producers' well heads or central dispatch locations by means of the Company's local gathering, low pressure pipelines. The gathering lines are then connected to the Company's larger diameter, higher pressure transportation pipelines that require the gas to be compressed. In order to sell liquids rich gas to power generation, industrial and utility customers or deliver it to an interstate pipeline, it is necessary to process the gas in order to remove any NGLs or condensates. The Company has, in the past, purchased additional third party processing capability in order to process all the gas that enters its system. The Company does not build its processing plants with excess capacity; the Company seeks to maintain an overall balance across the gathering, transportation and processing elements of its system as the Company views the combination of its assets as an integrated whole that allows its producers to deliver to the Company either wet or dry gas that is then processed and treated before being delivered from the system to its power generation, industrial and utility customers. The Company is currently building additional processing and treating capacity in order to better balance the integrated system and reduce the need to purchase third party processing capability. The Company manages its operations as one integrated process that buys or transports wet or dry gas and delivers dry gas and NGLs to the end market customers. The Chief Operating Decision Manager operates the business as a collection of transmission pipelines with various levels of treating and processing and a similar type or class of customers across the system, utilizing similar contractual arrangements and generating similar economic returns. The Company manages cash flow on an organizational level and makes all capital expenditure decisions based upon the total Company performance. Therefore, the Company reports its business as a single segment.

The comparability of the operating results for the Predecessor and those of the Company for subsequent periods is affected by purchase accounting adjustments to the values of plant, property and equipment acquired and the ensuing effect upon depreciation expense, the incurrence of debt to fund the Acquisition and the resulting deferred financing costs and interest expense and the costs associated with establishing the Company as a stand-alone entity.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

contingent assets and liabilities that exist at the date of the financial statements as well as the reported amounts of revenues and expenses during the reporting periods. Although these estimates are based on management's best available knowledge of current and future events, actual results may differ from those estimates.

Subsequent events have been evaluated through April 20, 2012, the date these financial statements were available to be issued.

Revenue Recognition The Company and the Predecessor record revenue and related costs for gas and NGL sales and transportation services in the period in which they are earned. Revenue primarily consists of the sale of natural gas and liquids along with fees earned from its gathering and processing operations. Under certain agreements, the Company purchases natural gas from producers at receipt points on the pipeline systems, and then sells the natural gas, or produced NGLs, if any, at delivery points on its systems. The Company records revenue and cost of product sold on a gross basis for these transactions where the Company acts as principal and takes title to the natural gas. The Company also has contracts where it does not take title to the gas and charges fees for providing services such as gathering, treating or transportation and the Company records these fees separately in revenues as transportation, gathering and processing fees. The Company recognizes revenue when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectability is reasonably assured.

For the period from January 1, 2009 to July 31, 2009 (Predecessor), and for the period from June 2, 2009 to December 31, 2009 and for the years ended December 31, 2010 and December 31, 2011 (Successor), the Company had the following revenue by category (dollars in thousands):

	Predecessor	Southcross Energy LLC		
	Period From January 1, 2009 to July 31, 2009	Period From June 2, 2009 to December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011
Revenue				
Sales of natural gas	$ 284,980	$ 158,805	$ 379,476	$ 385,513
Sales of NGLs and condensate	35,601	34,880	93,592	106,487
Transportation, gathering, and processing fees	9,607	12,298	25,080	30,102
Other revenues	682	651	599	1,047
Total revenue	$ 330,870	$ 206,634	$ 498,747	$ 523,149

The Company derives revenue in its business from the following types of arrangements:

Fixed-Fee. The Company receives a fixed fee per unit of natural gas or NGL volume that it gathers at the wellhead, processes, treats, fractionates, compresses and transports. Some of the

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Company's arrangements also provide for a fixed fee for guaranteed transportation capacity on its systems.

Fixed-Spread. Under these arrangements, the Company purchases natural gas from producers or suppliers at receipt points on its systems at an index price less a fixed amount and sells an identical volume of natural gas at delivery points on its systems at a price that is greater than the purchase price.

Percent-of-Proceeds ("POP"). In exchange for processing services, the Company remits to a producer customer a percentage of the proceeds from sales of residue natural gas and/or NGLs that result from natural gas processing, or in some cases, a percentage of the physical natural gas and/or NGLs at the tailgate of its processing plant, and the Company retains the balance of the proceeds or physical commodity for its own account. On its Gulf Coast System in South Texas, the Company arranges for other parties to process natural gas on its behalf. The most significant of these arrangements is with Formosa Hydrocarbons Company, Inc. ("Formosa"), an affiliate of Formosa Plastics Corporation, U.S.A. The Company's processing contract with Formosa entitles it to the greater of (1) a fixed percentage of the value of the NGLs resulting from processing plus 100% of the value of the residue natural gas (an "upgrade" percent-of-proceeds payment) and (2) the value of the unprocessed volume of natural gas priced relative to the same index prices pursuant to which the Company acquired the natural gas (a "floor" percent-of-proceeds payment). The current arrangement with Formosa will expire in January 2013.

Cash and Cash Equivalents Cash and Cash equivalents include all cash balances and investments in highly liquid financial instruments purchased with original maturities of three months or less.

Allowance for Doubtful Accounts In evaluating the collectability of its accounts receivable, the Company performs ongoing credit evaluations of its customers and adjusts payment terms based upon payment history and the customer's current creditworthiness, as determined by the Company's review of the customer's credit information. The Company extends credit on an unsecured basis to many of its customers. As of, and for the years ended, December 31, 2010 and 2011, the Company recorded no allowance for uncollectable accounts receivable.

Property, Plant and Equipment Property, plant and equipment, consisting primarily of pipelines, processing and treating equipment and facilities, are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired.

The Company capitalizes expenditures related to property, plant and equipment that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are replaced, improved, or the useful lives of which have been extended; and (3) all land, regardless of cost. Maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred, except for major overhauls of gas compressors, which are capitalized. Gas required to maintain pipeline minimum pressures ("Line Pack") is capitalized and classified as property, plant and equipment.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Costs related to projects during construction, including interest on funds borrowed to finance the construction of facilities, are capitalized as construction in progress. For the years ended December 31, 2010 and 2011, the Company capitalized interest of $0 and $1.8 million, respectively. Construction in progress balances are transferred to property, plant and equipment when the assets become ready for their intended use. Depreciation expense is based on cost primarily using the straight line method over the expected useful lives of the related assets. The estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of the assets. As circumstances warrant, depreciation estimates are reviewed to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values which would impact future depreciation expense.

The Company had no capital leases as of December 31, 2010 and 2011.

Rights of Way As part of the Acquisition, the Company assumed certain contractual rights under Right of Way ("ROW") agreements that allow the Company to gain access to and maintain the Company's pipelines and gathering lines in Texas, Mississippi and Alabama which traverse property owned by third parties. The carrying values associated with the ROW recorded in connection with the Acquisition are amortized over their expected useful life of 15 years.

The Company capitalizes costs associated with obtaining ROW to facilitate the building and maintenance of new pipelines and depreciates such costs over the life of the associated pipeline. The ROW agreements require the Company to make periodic (usually annual) renewal payments to property owners, although some are paid several years in advance. Annual renewal ROW payments are expensed when paid, while renewal payments under longer term ROW agreements are amortized over the terms of the agreements.

Intangible Assets The fair market value of the assets acquired in the Acquisition was determined to be equal to the purchase price of the entity, and therefore no goodwill was recorded as a result of the Acquisition. Substantially all of the contracts obtained in the Acquisition were determined to be either at current market prices or were short term in duration and subject to cancelation and renegotiation by either the Company or its counterparties. The fair market value of the assets acquired in the acquisition of EAI, effective September 1, 2011, was determined to be equal to the purchase price of the entity, and therefore no goodwill was recorded as a result of the acquisition. The Company attributed $1.7 million to the value of the long term customer contracts assumed in the EAI acquisition and is amortizing this over the expected life of the contracts which has been estimated at thirty years.

As of December 31, 2010 and 2011, the Company had net intangible assets of $0 and $1,681,000, respectively.

Environmental Matters The operations of the Company are subject to various federal, state and local laws and regulations relating to protection of the environment. Although the Company believes that it is in compliance with applicable environmental regulations, risk of costs and liabilities are inherent in pipeline and processing plant ownership and operation, and there can be no assurances that

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

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2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

significant costs and liabilities will not be incurred by the Company. Management is not aware of any contingent liabilities that currently exist with respect to environmental matters.

Asset Retirement Obligations The Company evaluates whether any future asset retirement obligations exist and estimates these costs for some future event. The Company did not provide any asset retirement obligations as of December 31, 2010 and 2011 or in connection with the Acquisition because it does not have sufficient information to reasonably estimate such obligations due in part to the fact that the Company has no intention of discontinuing the use of any significant assets or does not have a legal obligation to do so.

Income Taxes Provision for income taxes is attributable to the state tax obligations of the Company under the gross margin tax enacted by the State of Texas. There are no related deferred tax assets or liabilities.

The Company and the Predecessor were structured as a partnership for federal income tax purposes and they are not subject to federal income taxes. As a result, the owners of both entities are individually responsible for paying federal income taxes on their share of the taxable income. The Company follows the guidance for uncertainties in income taxes pursuant to which a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the more-likely-than-not criteria. The Company has not recorded any uncertain tax positions meeting the more-likely-than-not criteria as of December 31, 2010 and 2011.

Financial Instruments and Derivative Financial Instruments The accounting guidance related to derivative instruments and hedging activities requires the recognition of derivatives in the balance sheet and the measurement of those instruments at fair value. The Company's financial instruments include cash and cash equivalents, accounts receivable, accounts payable, fixed rate debt, variable rate debt and swap contracts based upon natural gas price indices. The Company does not hold or issue financial instruments or derivative financial instruments for trading purposes.

In its normal course of business, the Company enters into month-ahead swap contracts in order to economically hedge its exposure to certain intra-month natural gas index pricing risk. On February 17, 2011, the Company entered into an interest rate cap contract effective March 31, 2011 for $80 million notional amount of its debt. The contract effectively caps the Company's US Dollar LIBO based interest rate exposure on that portion of its debt on a sliding scale.

The Company records the realized gains and losses on the month-ahead swap contracts as revenues in the statement of operations. The realized and unrealized gains and losses on the interest rate cap contract are recorded as interest expense.

The Company measures the derivatives at fair value on a recurring basis using the best information and techniques available, which are primarily Level 2 inputs as defined in the fair value hierarchy. The derivatives are not designated as hedging instruments, and therefore any unrealized gain or loss is reported within the statement of operations.

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

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2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The Predecessor used derivatives to hedge against changes in cash flows related to product price risks for natural gas and liquids, generally up to one year out. All of the Company's obligations and exposure under these derivatives were settled as part of the Acquisition. The Predecessor determined the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying forward market price at the determination date. The asset or liability related to the derivative instruments was recorded on the balance sheet at fair value. The Predecessor designated these derivatives for natural gas and liquids as cash flow hedges for accounting purposes.

The Predecessor recorded realized and unrealized gains and losses on commodity related derivatives that were not designated as hedges, as well as the ineffective portion of designated derivatives, as gain or loss on derivatives in the combined statement of operations, which are also reported within revenues. The Predecessor recorded unrealized gains and losses on effective cash flow hedge derivatives as a component of accumulated other comprehensive income. When a hedged transaction occurred, the realized gain or loss on the hedge derivative was transferred from accumulated other comprehensive income to earnings, and reported within revenues. Settlements of derivatives are included in cash flows from operating activities for both the Company and the Predecessor.

Operational Balancing Agreements and Natural Gas Imbalances To facilitate deliveries of natural gas and provide for operational flexibility, the Company has operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of natural gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than that scheduled, a natural gas imbalance is created. The imbalance is settled through periodic cash payments or re-paid in-kind through future receipt or delivery of natural gas. Natural gas imbalances are classified as other current assets or other current liabilities on the balance sheet based on the market value.

Impairment of Long-Lived Assets The Company reviews its long-lived assets whenever events or circumstances such as economic obsolescence, business climate, legal and other factors indicate that the entity may not recover the carrying value of the assets. The Company continually monitors its business, the market and economic environment to identify indicators that could suggest the carrying value of an asset may not be recoverable. The carrying value of such assets is deemed to be impaired if the projected undiscounted cash flows are less than the carrying value. If there is such impairment, a loss would be recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows, supported by available market valuations, if applicable. No impairment charges were recorded for any periods presented.

Debt Issuance Costs Costs incurred in connection with the issuance of long term debt are deferred and charged to interest expense over the term of the related debt.

Earnings Per Common Unit The Company has included a calculation for earnings per common unit for all periods presented in which common units were outstanding. The Company calculates

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

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2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

earnings per common unit by first deducting the amount of cumulative returns on both the Redeemable Preferred and Preferred units from net income, and dividing this amount by the weighted average number of vested common units (including both the vested Class A common units and Class B units). For all periods presented in which common units were outstanding, no unvested common units were included in the computation of the diluted per-unit amount because all would have been antidilutive to the net loss per common unitholder. The amount of unvested common units that were not included in the computation of diluted per-unit amounts were 276,000 units, 275,381 units, and 274,762 units for each of the 2009, 2010, and 2011 Successor Periods, respectively.

Accounting Pronouncements Recently Adopted Accounting standard-setting organizations frequently issue new or revised accounting rules. The Company regularly reviews all new pronouncements to determine their impact, if any, on the financial statements. As of the date of these financial statements, there are no new pronouncements that are expected to materially impact the financial statements.

3. ACQUISITIONS

2009 Acquisition

Consistent with the Company's strategy to invest in the midstream energy sector, the Company acquired a business (Predecessor), which included entities and assets, from Crosstex on August 6, 2009 (effective August 1, 2009). The business acquired from Crosstex included natural gas gathering and transportation assets located in Texas, Mississippi and Alabama and processing facilities located in Texas. As part of the Acquisition, the Company acquired SWE Mississippi Pipeline Ltd. ("SWE" or "Delta Pipeline"). Delta Pipeline held certain gathering pipeline assets under construction in Mississippi for which the Company assumed responsibility to complete and place the pipeline into operation. This acquisition was accounted for as a business combination using the purchase method of accounting. Under the purchase method of accounting, the Company's identifiable assets acquired and liabilities assumed were recorded based upon the fair values determined as of the date of acquisition. The purchase price of the business from Crosstex was $217.6 million. The purchase price of the Delta Pipeline was $16.2 million.

The fair values of property, plant and equipment were determined based upon assumptions related to expected future cash flows, discount rates, and asset lives using currently available information. The Company utilized a mix of the cost, income and market approaches in determining the estimated fair values of such assets. The fair value measurements and models are classified as non-recurring level 3 measurements consistent with accounting standards related to the determination of fair value.

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3. ACQUISITIONS (Continued)

Identified assets acquired and liabilities assumed are as follows (dollars in thousands):

Current assets	$ 4,160
Property, plant and equipment	234,579
Total assets acquired	238,739
Current liabilities	4,949
Total liabilities assumed	4,949
Net identifiable assets acquired	$ 233,790

Substantially all of the contracts assumed in the Acquisition either were determined to be at current market prices or were short term in duration and subject to cancelation and renegotiation by either the Company or its counterparties. The Company determined that the purchase price was equal to the fair value of net assets acquired, thus no goodwill was recorded.

2011 Acquisition of EAI

Consistent with the Company's strategy to invest in the midstream energy sector, the Company completed the acquisition of EAI from Enterprise GTM Holdings L.P. for $21.8 million, effective September 1, 2011. EAI owned approximately 388 miles of 2-inch to 16-inch natural gas pipeline assets located in northwest and central Alabama, provides gathering, transportation and compression services and engages in the purchase and sales of natural gas. This acquisition added significant scale to the Company's existing network and capability in Alabama. The Company's identifiable assets acquired and liabilities assumed were recorded based upon the fair values determined as of the date of acquisition.

The fair values of property, plant and equipment were determined based upon assumptions related to expected future cash flows, discount rates, and asset lives using currently available information. The Company utilized a mix of the cost, income and market approaches in determining the estimated fair values of such assets. The fair value measurements and models are classified as non-recurring level 3 measurements consistent with accounting standards related to the determination of fair value. The Company has not completed the final purchase price allocation to the assets acquired and liabilities assumed as of December 31, 2011 because the Company has not completed its determination of the valuation of rights-of-way.

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3. ACQUISITIONS (Continued)

Identified assets acquired and liabilities assumed are as follows (dollars in thousands):

Current assets	$ 3,374
Property, plant and equipment	19,300
Intangible assets	1,700
Total assets acquired	24,374
Current liabilities	2,597
Total liabilities assumed	2,597
Net identifiable assets acquired	$ 21,777

The Company attributed $1.7 million to the value of long term contracts assumed in the acquisition, the majority being for life of lease which has been determined to be thirty years or the expected life of the pipelines. The Company determined that the purchase price was equal to the fair value of net assets acquired, thus no goodwill was recorded.

Transactions and Related Costs The Company expensed $2.96 million and $0.15 million of transaction costs in 2009 and 2010, respectively, associated with the 2009 Acquisition of the business of which $0.75 million was paid in 2009 to related parties. In 2011, the Company expensed $0.2 million of transaction costs associated with the acquisition of EAI. These costs were all incurred in the Successor Periods and have been reported within transaction costs.

In conjunction with the Acquisition, the Company executed a transition services agreement with Crosstex under which Crosstex agreed to provide gas control, operating, information technology, regulatory, contract administration, and selected accounting services over a period of four months ending December 1, 2009, during which time the Company hired and trained personnel, acquired equipment and facilities, installed standalone computer systems, and became functionally independent. The Company paid Crosstex $1.0 million for the services provided during transition which is included in G&A expenses.

Unaudited Pro Forma Financial information The following unaudited pro forma financial information assumes that the above acquisitions occurred on June 2, 2009 (for the Acquisition) and January 1, 2010 for the EAI acquisition. The unaudited pro forma information is not necessarily indicative of what the Company's financial position or results of operation would have been if the

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3. ACQUISITIONS (Continued)

transactions had occurred on those dates, or what the Company's financial position or results from operations will be for any future periods.

	Period from June 2, 2009 (date of inception) to December 31, 2009(1)	For the year ended December 31, 2010	For the year ended December 31, 2011
		(in thousands)	
Revenue	$ 283,555	$ 541,618	$ 548,152
Net Income	4,275	8,891	7,789

(1) Pro forma adjustments for the period June 2, 2009 to December 31, 2009 consist of adjustments for the 2009 Predecessor Period, including revenues and costs for June 2, 2009 through July 31, 2009, interest expense of $1,313,000 and income tax expense of $20,000.

4. PROPERTY, PLANT, AND EQUIPMENT

	Estimated Useful Life	December 31, 2010	December 31, 2011
		(in thousands)	
Pipeline	30	$ 176,545	$ 230,866
Treating plants	15	4,367	5,294
Processing plants	15	21,530	31,696
Rights of way	15	19,428	20,249
Compressors	7	11,515	16,078
Furniture, fixtures and equipment	5	2,090	2,814
Line pack		1,000	1,083
Land and easements		3,120	3,139
Construction in progress		4,935	86,189
Total property, plant and equipment		244,530	397,408
Accumulated depreciation and amortization		(15,221)	(27,547)
Net property, plant and equipment		$ 229,309	$ 369,861

Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as shown in the above table.

5. INTANGIBLE AND OTHER ASSETS

As part of the EAI acquisition, which was effective September 1, 2011, the Company assumed and attributed $1.7 million to the value of long term supply contracts with existing producers. The majority of these contracts are life of lease and the Company has assumed that the useful economic lives of these producing leases will be at least as long as the expected life of our acquired pipelines which is

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5. INTANGIBLE AND OTHER ASSETS (Continued)

30 years. We will amortize the value of the intangible asset on a straight line basis for 360 months. We have amortized $18,889 for the year ended December 31, 2011, which is reported within depreciation and amortization expense.

In conjunction with the financing obtained from the syndicate of lenders led by Wells Fargo Bank, N.A., the Company paid $5.9 million to Wells Fargo Bank, N.A., the lead lender, on August 6, 2009. These deferred financing costs were amortized to interest expense over the primary term of the original loan (through August 6, 2012) using the effective interest rate method.

In addition, the Company paid $0.75 million for fees related to the First Amendment of the Credit Agreement and additional borrowings of $14.2 million at December 30, 2010. These deferred financing costs along with the balance of the deferred financing costs of $2.8 million at December 31, 2010 are being amortized to interest expense over the amended term of the loan through June 30, 2014. The Company amortized $0.9 million and $2.2 million of these deferred financing costs to interest expense for the period from June 2, 2009 to December 31, 2009 and for the year ending December 31, 2010, respectively.

The Amended and Restated Credit Agreement entered into in June of 2011 was accounted for as an extinguishment of debt, and accordingly, the Company has reported a $3.2 million loss on the extinguishment of debt for the year ended December 31, 2011. The Company paid $2.6 million in fees related to the Amended and Restated Credit Agreement. Of these fees paid in connection with the Amended and Restated Credit Agreement, $0.8 million has been expensed and included within the loss on extinguishment of debt. The remaining $2.5 million in loss on extinguishment of debt is associated with previously recorded deferred financing costs that have been written off as a result of the extinguishment. The outstanding Amended and Restated Credit Agreement fees and a portion of the remaining balance of deferred financing cost as of June 10, 2011 will be amortized over the five year life of the Amended and Restated Credit Agreement.

The net carrying amount of deferred financing costs is included in the Balance Sheet in other assets. The Company has recognized deferred financing fee amortization of $0.9 million for the year ended December 31, 2011, which is reported within interest expense.

6. MEMBERS' EQUITY

Southcross Energy LLC

In conjunction with the Acquisition, certain investment entities managed by Charlesbank contributed $116.7 million in cash to the Company in exchange for $115.6 million of preferred and a controlling interest of $1.1 million of Class A common units of the Company. Members of the Company's management and certain other individuals and entities contributed a total of $3.1 million in cash or promissory notes in exchange for $2.8 million of preferred and $0.3 million of common equity of the Company including the Class A common units and Class B units discussed below. As provided by the Company's limited liability company agreement, subsequent to the closing of the Acquisition and

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6. MEMBERS' EQUITY (Continued)

the funding provided by Charlesbank at closing, Charlesbank sold $5.0 million of its interests in the Company to an affiliate of Wells Fargo Securities, LLC.

As of December 31, 2010, the Company's common equity was comprised of 1,197,629 Class A common units, 218,102 unvested Class A common units, and 57,279 Class B units. As of December 31, 2011, the Company's common equity was comprised of 1,198,246 Class A common units, 217,483 unvested Class A common units, and 57,279 Class B units. The Class B units have the same distribution and liquidation rights as the Class A common units, however they do not have voting rights. All Class A common and Class B units were purchased for, and have a par value of, $1.00 per unit.

On August 6, 2009, an officer of the Company borrowed $150,000 from the Company to fund the acquisition of units of preferred and common equity of the Company pursuant to the terms and conditions of a promissory note executed between the officer and the Company. As of December 31, 2010, the outstanding balance of the loan was $112,500 and was presented on the balance sheet as a reduction of members' equity. The officer paid the remaining principal balance of $112,500 on July 28, 2011. The balance as of December 31, 2011 was $26,000, which represents the unpaid interest outstanding on the note, and was paid in full subsequent to December 31, 2011.

As of December 31, 2011 the Company does not have any long-term incentive plans or shares authorized for issuance of share-based compensation.

As noted above, in connection with the Acquisition, five individuals comprising our management team were allowed to purchase, individually or indirectly through Estrella Energy, LP, Class A common and Class B units along with our sponsor for the same value per unit as our sponsor ($1.00 per unit). Certain of the Class A common units and all of the Class B units contain time-and performance-vesting conditions. Time-vesting units vest ratably over five years subject to certain accelerated vesting based primarily on a change in control or certain termination clauses. Performance-vesting units will vest, if at all, upon Charlesbank attaining certain investment multiples and internal rates of return in connection with a liquidity event. Both the time- and performance-vesting units require continued employment through any vesting date.

No compensation expense has been recorded for the time-based vesting units as the price paid by the individuals was equal to the fair value of the units on the date purchased. No compensation expense has been recorded for the performance-based vesting units as the price paid for the units was equal to the fair value of the units on the date purchased. Upon an employee's termination of employment, any unvested incentive units are subject to the Company's right, but not obligation, to repurchase such units at the employee's initial acquisition cost (or less in certain circumstances).

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6. MEMBERS' EQUITY (Continued)

The following table provides information regarding the incentive units purchased by management, individually or indirectly through Estrella Energy, LP in August 2009:

	Number of Units Purchased		Number of Units Vested	
	Subject to Time Vesting	**Subject to Performance Vesting**	**Subject to Time Vesting**	**Subject to Performance Vesting**
Class A	3,096	215,625	1,239(1)	
Class B	57,278		22,911(2)	

(1) Includes 619 and 620 units that vested in 2010 and 2011, respectively.

(2) Includes 11,456 and 11,455 units that vested in 2010 and 2011, respectively.

As of December 31, 2011, no additional units have been issued, granted or forfeited since the Company's inception.

Predecessor

The Predecessor's owner's equity was recorded as an investment in subsidiaries and all transactions were settled through an intercompany advances account, which reflected all movements in cash between the Predecessor and its parent, Crosstex. Crosstex utilized a central treasury function that controlled all cash disbursements and provided all sources of funding on a company-wide basis. Immediately prior to the Acquisition, the advances were converted to owner's equity.

7. PREFERRED UNITS

Preferred Units

The Company's preferred units are comprised of 11,850,374 cumulative units with a par value of $10.00 per unit, all of which were outstanding for all periods presented. The preferred units accrue value (in the form of an additional preferential right to receive cumulative distributions) at a rate of 10% per annum, compounded quarterly. Except in the case of cash distributions made for the purpose of paying federal income taxes, which are made to both preferred unit and common equity owners in direct proportion to the owners' respective share of taxable income, owners of the preferred units receive cash distributions before owners of common equity. The preferred units and their cumulative return are subordinate to the redeemable preferred units and their cumulative return discussed below. As discussed within Note 6 and with the exception of cash distributions for federal income tax purposes, the Company's credit agreement includes certain covenants that restrict its ability to pay cash distributions to its owners. The Company adjusts the carrying value of the preferred units to reflect the cumulative right to receive distributions on a quarterly basis. As of December 31, 2010 and December 31, 2011, the preferred unitholders' right to receive future cash distributions included an additional $17.6 million and $31.8 million as a result of the cumulative preferred return on such units.

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7. PREFERRED UNITS (Continued)

Redeemable Preferred Units

On June 10, 2011, in conjunction with the Company entering into an Amended and Restated Credit Agreement with its lenders, Charlesbank and most of the Company's existing investors, including members of management, contributed a total of $15.0 million to the Company in exchange for 1,500,000 redeemable preferred units. The redeemable preferred units have a par value of $10.00 per unit and accrue value (in the form of an additional preferential right to receive distributions) at a rate of 18% per annum, compounded quarterly. These units are redeemable by the Company in whole or in part at any time, or shall be redeemed by the Company promptly after the satisfaction by the Company of all its obligations under the Amended and Restated Credit Agreement. The Company adjusts the carrying value of the redeemable preferred units to reflect the cumulative right to receive distributions on a quarterly basis. As of December 31, 2011, the redeemable preferred unitholders' right to receive future cash distributions included an additional $1.6 million as a result of the cumulative preferred return on such units.

8. LONG TERM DEBT

Southcross Energy LLC

As of December 31, 2011, the Company had an outstanding term loan of $163.3 million with a LIBO interest rate of 3.58% and a revolver loan of $45.0 million with an interest rate of 3.67%. As of December 31, 2011, the Company was in compliance with all loan covenants.

Original Credit Agreement August 6, 2009

On August 6, 2009, in conjunction with the acquisition of the businesses from Crosstex and Southwest, the Company borrowed $125.0 million and arranged for a $30.0 million revolver under the terms of a Credit Agreement executed among the Company and a syndicate of lenders led by Wells Fargo Bank, N.A. Quarterly scheduled principal payments of $3.1 million, beginning on December 31, 2009, were due through June 30, 2012, with the remaining balance maturing on August 6, 2012. In addition to scheduled payments, the Credit Agreement requires quarterly excess cash flow principal prepayments to be made by the Company based on a formula tied to the Leverage Ratio (the ratio of the Company's outstanding debt to the last 12 months' earnings before interest, taxes, depreciation and amortization (adjusted to remove the effects of unusual nonrecurring items)). The percentage of quarterly excess cash which is swept for prepayment was reduced as the Leverage Ratio declined. For the year ended December 31, 2010, the Company made total repayments on the term loan of $19.1 million, including $2.3 million of principal repayments as a result of excess cash flow covenants.

Interest rates applied to the outstanding balance of the loan are tied to either one-month, three-month, or six-month LIBO rates (as defined in the Credit Agreement) or an Alternate Base Rate (ABR), selected at the Company's option, plus a margin which also fluctuates in relation to the Leverage Ratio. LIBO loan rates include the applicable margin (see the table below) and through December 30, 2010, were subject to a LIBO floor of 2.00%. ABR loan rates include the applicable

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8. LONG TERM DEBT (Continued)

margin (see the table below) plus the greatest of (a) the prime rate in effect at the principal offices of the lead lender (b) the Federal Funds Rate plus 1.5%, and (c) one-month LIBO rate plus 1.5%.

For the period from August 6, 2009 to December 29, 2010, the applicable margins that apply to both the term and revolver borrowings, excess cash prepayment percentages, and letter of credit ("LC") fee percentages of the credit agreement are presented in the following table.

Leverage Ratio	LIBO Loan Margin	ABR Loan Margin	Excess Cash Prepayment	LC Fees
Above 3.5x	4.50%	3.50%	100%	4.50%
From 3.0x to 3.5x	4.25	3.25	75	4.25
From 2.5x to 3.0x	4.00	3.00	50	4.00
From 2.0x to 2.5x	3.75	2.75	50	3.75
Below 2.0x	3.75	2.75		3.75

The Company elected to use ABR loans that bore a weighted average interest rate of 6.7% and 6.4% for the years ended December 31, 2009 and December 31, 2010, respectively.

Amendment to the Original Credit Agreement December 30, 2010

On December 30, 2010, the Company entered into the First Amendment of the Credit Agreement, which extended the maturities of its debt from August 6, 2012 to June 30, 2014 and lowered the applicable interest rate margins. The terms of the amended credit agreement increased the term loan borrowings limit by $14.2 million to $115.0 million and, as a result, the Company increased borrowings by an incremental $14.2 million. Per the terms of the Amended Credit Agreement, quarterly scheduled principal payments were reduced to $2.9 million commencing on March 31, 2011 with the remaining balance maturing on June 30, 2014. In addition, the Amended Credit Agreement increased the limit on the use of the revolver on LCs to no more than $30.0 million and provided for the ability to expand the revolver to $55.0 million upon request by the Company.

Per the amended credit agreement of December 30, 2010, through loan maturity of June 30, 2014, the applicable margins, excess cash prepayment percentages, and LC fee percentages are presented in the following table.

Leverage Ratio	LIBO Loan Margin	ABR Loan Margin	Excess Cash Prepayment	LC Fees
Above 3.5x	3.25%	2.25%	50%	3.25%
From 3.0x to 3.5x	3.00	2.00	50	3.00
From 2.5x to 3.0x	2.75	1.75	0	2.75
From 2.0x to 2.5x	2.50	1.50	0	2.50
Below 2.0x	2.50	1.50	0	2.50

As of December 31, 2010, the loans outstanding under the Amended Credit Agreement were an ABR loan of $14.2 million that bore interest at an effective rate of 5.5% and a LIBO loan of

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8. LONG TERM DEBT (Continued)

$100.8 million that bore interest at an effective interest rate of 3.52%. As of December 31, 2010, the Company was in compliance with all loan covenants.

Under the terms of the $30.0 million revolver, the Company had the ability to borrow cash or issue standby LCs totaling a combined $30.0 million with no more than $20.0 million being used for LCs. As of December 31, 2010, the Company had $16.6 million of outstanding LCs. There were no revolver loans outstanding during the fiscal year 2010. Accordingly, the Company had $13.4 million of availability under its revolver as of December 31, 2010.

Amended and Restated Agreement to the Original Credit Agreement June 10, 2011

On June 10, 2011, the Company entered into an Amended and Restated Credit Agreement ("Amended and Restated Credit Agreement") with a syndicate of lenders led by Wells Fargo Bank, N.A. with a maturity of June 10, 2016. The Company's term loan commitment increased from $115.0 million to $153.0 million in connection with the Amended and Restated Credit Agreement, and the Company received net proceeds of $30.0 million. The Amended and Restated Credit Agreement also gave the Company the right to draw down an additional term loan amount not to exceed $22.0 million by September 30, 2011, and on August 30, 2011, the Company borrowed an additional $21.9 million in the form of a LIBO loan with an interest rate of 3.23% to fund the acquisition of EAI. This agreement also provides the Company with a current revolving loan capacity of $150.0 million which includes a sub-limit of up to $50.0 million for LCs. This revolving loan capacity may be increased to $185.0 million by request of the Company subject to certain conditions. The Company used $120.7 million to pay off the existing loans, plus accrued interest, under the Amended and Restated Credit Agreement. Per the terms of the Amended and Restated Credit Agreement, the Company made a payment of $2.9 million on June 30, 2011 and thereafter quarterly scheduled principal payments are $4.4 million commencing on September 30, 2011, with the remaining balance maturing on June 10, 2016. For the year ended December 31, 2011, the Company made total principal repayments on the term loans of $16.4 million, including $1.9 million of principal repayments as a result of excess cash flow covenants.

Interest rates applied to the outstanding balance of the loan are tied to either one-month, three-month, or six-month LIBO rates plus a margin which also fluctuates in relation to the Leverage Ratio or an ABR selected at the Company's option, plus a margin which also fluctuates in relation to the Leverage Ratio. ABR loan rates include the applicable margin plus the greatest of (a) the prime rate in effect at the principal offices of the lead lender (b) the Federal Funds Rate plus 0.5%, and (c) one-month LIBO rates plus 1.0%.

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8. LONG TERM DEBT (Continued)

Per the Amended and Restated Credit Agreement, through loan maturity of June 10, 2016, the applicable margins for term and revolver borrowings, and LC fee percentages are presented in the following table.

Leverage Ratio	LIBO Loan Margin	APR Loan Margin	LC Fees
Above 4.5x	3.25%	2.25%	3.25%
From 4.0x to 4.5x	3.00	2.00	3.00
From 3.5x to 4.0x	2.75	1.75	2.75
From 3.0x to 3.5x	2.50	1.50	2.50
Below 3.0x	2.25	1.25	2.25

All the Company's property, including all of its ownership interests in its subsidiaries, is pledged, or was pledged, as collateral under the Company's credit agreements listed above. The terms of the credit facilities contain customary covenants, including those that restrict the Company's ability to make or limit certain payments, distributions, acquisitions, loans, or investments, incur certain indebtedness or create certain liens on its assets, consolidate or enter into mergers, dispose of certain of the Company's assets, engage in certain types of transactions with its affiliates, enter into certain sale/leaseback transactions and modify certain material agreements.

The events that constitute default under all of the credit facilities include, among other things, the failure to pay principal and interest on the indebtedness under the facilities when due, failure to comply with certain covenants or breach of representations and warranties made under the credit facilities, certain bankruptcy, dissolution, liquidation or other insolvency events, occurrence of a material adverse change or a change of control. As of December 31, 2011, the Company was in compliance with all loan covenants.

As of December 31, 2011, scheduled maturities of debt are as follows:

Year	Amount of Maturing Debt (in thousands)
2012	$ 17,490
2013	17,490
2014	17,490
2015	17,490
2016	138,320
Total	$ 208,280

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8. LONG TERM DEBT (Continued)

Predecessor

The Predecessor had no debt or related interest expense as all funding for the entity was provided on a pass-through basis through an intercompany clearing account by the central treasury function of the parent entity that controlled all cash disbursements and provided all sources of funding.

9. CONCENTRATION OF CREDIT RISK AND CUSTOMERS

The Company's primary markets are in Texas, Alabama and Mississippi. The Company has a concentration of trade accounts receivables 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 similarly affected by changes in economic, regulatory or other factors. The Company analyzes the customers' historical financial and operational information prior to extending credit.

Formosa Hydrocarbons Company Inc. and Sherwin Alumina Company are significant customers for the Company, each representing at least 10% of the Company's consolidated revenue, and each constituting $106.6 million and $65.4 million, respectively, of revenues for the year ended December 31, 2010 and $108.8 million and $81.2 million, respectively, of revenues for the year ended December 31, 2011. The Company's top ten customers represent 74.2% of consolidated revenue for the year ended December 31, 2010 and 73.1% of consolidated revenue for the year ended December 31, 2011.

10. COMMITMENTS AND CONTINGENCIES

Leases The Company has a non-cancelable lease for its office facilities in Dallas, Texas which expires August 16, 2016. Lease expense was $65,000, $228,000 and $277,000 for the reporting periods ended December 31, 2009, 2010 and 2011, respectively, and has been reported within G&A expense.

The schedule of future minimum lease payments for operating leases that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2011 is as follows (dollars in thousands):

Years Ending December 31,	Operating Leases
2012	$ 321
2013	331
2014	342
2015	350
2016	239

Litigation The Company is from time to time subject to claims and suits arising in the ordinary course of business, including those relating to contractual obligations. The Company accrues for potential liabilities involved in these matters as they become probable and can be reasonably estimated. The Company has not been involved in any significant claims or litigation for the period from June 2,

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

10. COMMITMENTS AND CONTINGENCIES (Continued)

2009 to December 31, 2009 and the years ended December 31, 2010 and December 31, 2011, respectively and had no litigation accrual as of December 31, 2010 or December 31, 2011.

Outstanding Commitments on Expansion Projects The Company has initiated plans to expand its capabilities. During 2011, the Company placed purchase orders to start the construction of a new 200 MMcf/d Woodsboro processing plant in Refugio County, Texas which has an estimated total cost of $97.0 million and is expected to come on line by June 2012. In addition, during November 2011, the Company finalized the acquisition of an existing fractionating facility and entered into contracts to refurbish and install this equipment at its Bonnie View fractionation site. The total estimated cost for this project is $27.4 million. As of December 31, 2011, the Company has $43.9 million in firm commitments outstanding for major projects.

11. DEFINED CONTRIBUTION BENEFITS

The Company established a 401(k) plan for its employees in 2009 in which virtually all employees are eligible to participate. The Company's contributions and expense to this plan, which are based upon the employees' contributions to the plan, were $88,000, $343,000 and $417,000 for the period from June 2, 2009 to December 31, 2009 and the years ended December 31, 2010 and 2011, respectively, and has been reported within operating expense or G&A expense depending on the employee's position.

The employees of the Predecessor were able to participate in the Predecessor's parent single employer 401(k) plan and became eligible upon the hire date. The plan allows for contributions to be made at each compensation calculation period based upon the annual discretionary contribution rate. A contribution of $210,000 was made to the plan for the period from January 1, 2009 to July 31, 2009.

12. RELATED PARTY TRANSACTIONS

In 2009, in connection with the formation of the Company and the Acquisition, the Company paid fees of $0.23 million to Charlesbank, and $0.52 million to Estrella Energy, LP ("Estrella"), an affiliate of the Company that is owned by members of management, and owns Class A Common units and Class B units. These fees were expensed and reported within transaction costs.

Charlesbank provides certain management services to the Company under the terms of an agreement with the Company which requires an annual management fee of $600,000. In 2009, 2010 and 2011, the Company incurred management fees from Charlesbank of $242,000, $600,000 and $600,000, respectively, for such services, which are reported within G&A expenses. In addition, in 2010 and 2011, the Company reimbursed Charlesbank $29,000 and $109,000 for other miscellaneous expenses, which also have been reported within G&A expenses. The Company paid Charlesbank an arrangement fee of $125,000 on August 6, 2009, associated with the financing of the Company, which was included in interest expense.

The Company entered into the credit agreements with syndicates of financial institutions and other lenders. These syndicates included affiliates of Wells Fargo Bank, N.A., which is a member of the investor group. See Note 8. Affiliates of Wells Fargo Bank, N.A. have from time to time engaged in

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

12. RELATED PARTY TRANSACTIONS (Continued)

commercial banking and financial advisory transactions with the Company in the normal course of business.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS

Southcross Energy LLC

Accounting standards related to the determination of fair value define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company uses the market approach for recurring fair value measurements and to maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company categorizes the liability recorded at fair value based upon the following fair value hierarchy:

Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. An active market is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 valuations use inputs, in the absence of actively quoted market prices, that are observable for the asset or liability, either directly or indirectly. Level 2 inputs include: (a) quoted prices for similar assets or liabilities in active markets, (b) quoted prices for identical or similar assets or liabilities in markets that are not active, (c) inputs other than quoted prices that are observable for the asset or liability such as interest rates and yield curves observable at commonly quoted intervals and (d) inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 valuations use unobservable inputs for the asset or liability. Unobservable inputs are used to the extent observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. The Company uses the most meaningful information available from the market combined with internally developed valuation methodologies to develop the best estimate of fair value.

The carrying amount reported in the balance sheets for cash and cash equivalents, trade accounts receivable and trade accounts payable approximates its fair value due to the short maturity of these instruments.

The Company determined that the fair value of debt as of December 31, 2011 approximated book value due to the fact that the Amended and Restated Credit Agreement was entered into on June 10, 2011 and that there has been no significant change in market conditions or its credit rating or pricing since that time. The Company determined that the fair value of debt as of December 31, 2010 approximated book value of the debt due to the fact that all outstanding loans were entered into and

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

13. FAIR VALUE OF FINANCIAL INSTRUMENTS (Continued)

priced as of December 30, 2010, which is the date that the Company entered into the First Amendment of the Credit Agreement as described in Note 8.

With regard to month-ahead swap contracts, the Company has utilized publicly available pricing of commodities to determine the fair value of these contracts. The Company defines these contracts as Level 2, as the index prices associated with such contracts is observable, and tied to the quoted first of the month natural gas index price. Based upon the receipt of this pricing from third parties, the Company deemed that these contracts are recorded at fair value and approximated book value.

Description	Fair value measurement as of December 31, 2011 Significant Other Observable Inputs (Level 2)
	(in thousands)
Interest rate cap	$ 21

14. DERIVATIVES

Southcross Energy LLC

In its normal course of business, the Company enters into month-ahead swap contracts in order to economically hedge its exposure to certain intra-month natural gas index pricing risk. The total volume of month-ahead swap contracts outstanding as of December 31, 2010 and 2011 was 372,000 MMBtu and 372,000 MMBtu, respectively. The Company defines these contracts as Level 2, as the index prices associated with such contracts is observable, and tied to the quoted first of the month natural gas index price. The fair value of such contracts was immaterial as of December 31, 2010 and 2011.

The components of realized (gain) losses on derivatives in the consolidated statements of operations, reported within Revenues, relating to such derivatives is as follows (dollars in thousands):

	Southcross Energy LLC		
	June 2, 2009 (Date of Inception) to December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011
Realized (gain) losses on derivatives	$ (134)	$ 355	$ 179

On February 17, 2011, the Company entered into an interest rate cap contract with Wells Fargo, N.A. effective March 31, 2011 for $80.0 million notional amount of debt. The contract effectively caps the Company's US Dollar LIBO based interest rate exposure on that portion of debt on a sliding scale that starts at 1.51% as of March 31, 2011 and increases to 4.57% at the end of the contract on June 30, 2014. The notional amount of debt declines over time so that the amount of debt covered by this contract is $65.0 million, $43.0 million and $23.0 million at December 31, 2011, 2012 and 2013, respectively. The Company defines this contract as Level 2. The unrealized and realized gains and losses are recorded in interest expense. The Company has not designated the interest rate cap as a

SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

14. DERIVATIVES (Continued)

hedging instrument for accounting purposes; therefore it is accounted for at fair value in the consolidated statement of operations, as follows (in thousands):

	Year ended December 31, 2011
Realized loss on interest rate cap	$ 147
Unrealized loss on interest rate cap	21

Predecessor

Commodity Swaps The Predecessor managed its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps were used to manage and hedge prices and location risk related to these market exposures. Swaps also were used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

The Predecessor commonly entered into various derivative financial transactions which it did not designate as hedges. These transactions included "swing swaps", "third party on-system financial swaps", "storage swaps", and "basis swaps". Swing swaps were generally short term in nature (one month) and were usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps were hedges that the Predecessor entered into on behalf of its customers who were connected to its systems, wherein the Predecessor fixed a supply or market price for a period of time for its customers, and simultaneously entered into a derivative transaction. Storage swap transactions protected against changes in the value of gas that the Predecessor had stored to serve various operational requirements. Basis swaps were used to hedge basis location price risk due to buying gas into one of the owned systems on one index and selling gas off that same system on a different index.

The components of (gain) losses on derivatives in the combined statements of operations, reported within Revenues, relating to commodity swaps are (dollars in thousands):

	Predecessor Period From January 1 to July 31, 2009
Change in fair value of derivatives that do not qualify for hedge accounting	$ 170
Realized gains on derivatives	(625)
Realized gains on cash flow hedges	(823)
Net gains related to commodity swaps	$ (1,278)

The Predecessor's counterparties to derivative contracts include BP Energy, Total Gas & Power, Morgan Stanley, J. Aron & Co., a subsidiary of Goldman Sachs, and Sempra Energy. Changes in the fair value of the Predecessor's non-designated derivative contracts were recorded in earnings in the

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14. DERIVATIVES (Continued)

period the transaction was entered into. The effective portion of changes in the fair value of cash flow hedges was recorded in accumulated other comprehensive income until the related anticipated future cash flow was recognized in earnings. The ineffective portion was recorded in earnings immediately. The change in fair value of non-designated derivative contracts, the realized settlement of cash flow hedges, and the ineffective portion of cash flow hedges are all reported within the Predecessor's revenues.

On all transactions where the Predecessor was exposed to counter-party risk, the Predecessor analyzed the counterparty's financial condition prior to entering into an agreement, established limits, and monitored the appropriateness of these limits on an ongoing basis.

As of the effective date of the Acquisition, Crosstex assumed all outstanding hedges and derivatives that had been attributed to the Predecessor including all liabilities and exposures associated with these contracts. The Company's obligation to these contracts was settled by payment of the agreed-to acquisition price.

15. PHANTOM UNITS PLAN

The Company has provided to certain key non-officer employees equity incentive units ("Phantom Units") in the Company. The Phantom Units only vest upon the occurrence of a change in control where more than 50% of the voting power of the Company changes hands, or upon the occurrence of a liquidity event where, through the sale of some portion of its ownership, the majority owner of the Company achieves or exceeds a targeted rate of return on its original investment. The number of Phantom Units earned and eligible for vesting increase over a period of years or through the achievement of certain rates of return by the majority owner of the Company, or a combination thereof. No fair value was attributable to the Phantom Units and no compensation expense associated with these units was recorded during the years ended December 31, 2011 and 2010 as it was not probable that the Phantom Units will vest. As of December 31, 2011 and 2010, the total number of authorized and issued Phantom Units was 10,832.

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SOUTHCROSS ENERGY LLC AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

FOR THE PERIOD FROM JANUARY 1, 2009 TO JULY 31, 2009 (PREDECESSOR PERIOD), AND FOR THE PERIOD FROM JUNE 2, 2009 (DATE OF INCEPTION) TO DECEMBER 31, 2009 AND AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2010 AND DECEMBER 31, 2011 (SUCCESSOR PERIOD)

16. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

The following table discloses certain cash payments for interest and taxes and the value of capital expenditures remaining in accounts payable (in thousands).

	Southcross Energy Predecessor	Southcross Energy LLC		
	January 1, 2009 to July 31, 2009	June 2, 2009 (Date of Inception) to December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011
Cash paid for interest	$ (1)	$	$ 6,241	$ 7,994
Cash paid for taxes			133	272

	As of December 31, 2010	As of December 31, 2011
Capital expenditure remaining in accounts payable	$ 632	$ 10,862

(1) The Predecessor had no debt or related interest expense as all funding for the entity was provided on a pass-through basis through an intercompany clearing account by the central treasury function of the parent entity that controlled all cash disbursements and provided all sources of funding.

17. SUBSEQUENT EVENTS

The Company entered into the First Amendment of the existing Amended and Restated Credit Agreement on February 7, 2012 with a syndicate of lenders led by Wells Fargo Bank, N.A. with a maturity of June 10, 2016. This change in the credit agreement was made to increase the Company's loan capability in order to satisfy the Company's operating and capital plans. The Company obtained modifications to the covenants to reflect its need for capital expansion to support its growth plans that include the construction of its Woodsboro processing plant and the Bonnie View fractionation site. The term loan commitment and revolver loan capacity have not been changed by this amendment though pricing has been changed on the higher permitted leverage ratio. The Company incurred $2.2 million in fees and expenses relating to this First Amendment of the existing Amended and Restated Credit Agreement which will be accounted for as deferred financing fees and amortized over the remaining life of this agreement.

On March 2, 2012, the Company entered into an Interest Rate Swap contract effective March 30, 2012 with the notional value of $150 million and maturity of June 30, 2014. Under the terms of this contract, we have fixed our LIBO base borrowings at 0.54% . The existing Interest Rate Cap contract with an amortizing notional value and maturity of June 30, 2014 has been terminated.

On March 20, 2012, Charlesbank contributed $25.3 million in cash and an affiliate of Wells Fargo Securities, LLC contributed $10 million in cash to the Company in exchange for 2.53 million units and 1.0 million units, respectively, of a new class, Series B, of cumulative preferred equity with a par value of $10.00 per unit. This cumulative preferred equity accrues value (in the form of a preferential right to receive distributions) at a rate of 18% per annum, compounded quarterly. Subsequently, the Company used $15.3 million to acquire and retire the units of an existing non-management unitholder.

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INDEPENDENT AUDITOR'S REPORT

To the Member of Enterprise Alabama Intrastate, LLC
Dallas, Texas

We have audited the accompanying balance sheet of Enterprise Alabama Intrastate, LLC (the "Company") as of December 31, 2010, and the related statements of income, cash flows, and member's equity for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing 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 Company 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 Company'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 audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2010, and the results of its operations and its cash flows for the year ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the Financial Statements, the accompanying financial statements have been prepared from the separate records maintained by Enterprise Products Operating LLC or affiliates and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
October 31, 2011

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Enterprise Alabama Intrastate, LLC

Balance Sheets

(Dollars in thousands)

	December 31, 2010	June 30, 2011
		(Unaudited)
Assets		
Current assets:		
Accounts receivable trade	$ 4,487	$ 3,412
Accounts receivable related parties	1,203	173
Total current assets	5,690	3,585
Property, plant and equipment, net	38,861	38,187
Total assets	$ 44,551	$ 41,772
Liabilities and Member's Equity		
Current liabilities:		
Accounts payable trade	$ 110	$ 120
Accrued gas payables	3,033	2,252
Other current liabilities	103	181
Total current liabilities	3,246	2,553
Other long-term liabilities	22	23
Commitments and contingencies		
Member's equity	41,283	39,196
Total liabilities and member's equity	$ 44,551	$ 41,772

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Enterprise Alabama Intrastate, LLC

Statements of Income

(Dollars in thousands)

	For the Year Ended December 31, 2010	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2011
		(Unaudited)	(Unaudited)
Revenues:			
Natural gas sales	$ 36,382	$ 19,288	$ 16,076
Transportation and gathering services	6,489	3,273	3,044
Total revenues	42,871	22,561	19,120
Cost and expenses:			
Cost of natural gas sales	34,110	18,122	15,058
Depreciation and accretion	1,477	740	735
Other operating costs and expenses	4,715	2,171	2,125
General and administrative costs	491	208	323
Total costs and expenses	40,793	21,241	18,241
Operating income	2,078	1,320	879
Net income	$ 2,078	$ 1,320	$ 879

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Enterprise Alabama Intrastate, LLC

Statements of Cash Flows

(Dollars in thousands)

	For the Year Ended December 31, 2010	For the Six Months Ended June 30, 2010 (Unaudited)	For the Six Months Ended June 30, 2011 (Unaudited)
Operating Activities:			
Net income	$ 2,078	$ 1,320	$ 879
Adjustments to reconcile net income to cash flows provided by operating activities:			
Depreciation, amortization and accretion	1,510	752	760
Gains from asset sales and related transactions	(3)	(1)	
Effect of changes in operating accounts:			
Accounts receivable trade	(696)	(165)	1,075
Accounts receivable related parties	(1,244)	(21)	1,006
Accounts payable trade	(180)	(75)	11
Accounts payable related parties		51	
Accrued gas payables	426	120	(781)
Other current liabilities	(196)	(170)	78
Net cash flows provided by operating activities	1,695	1,811	3,028
Investing Activities:			
Capital expenditures	(22)	(51)	(62)
Proceeds from asset sales and related transactions	7	1	
Cash used in investing activities	(15)	(50)	(62)
Financing Activities:			
Distributions to Member	(1,680)	(1,761)	(2,966)
Cash used in financing activities	(1,680)	(1,761)	(2,966)
Net change in cash and cash equivalents			
Cash and cash equivalents, beginning of period			
Cash and cash equivalents, end of period	$	$	$

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Enterprise Alabama Intrastate, LLC

Statements of Member's Equity

(Dollars in thousands)

	Enterprise GTM Holdings L.P. (100%)
Balance, January 1, 2010	$ 40,885
Net income	2,078
Distributions to Member	(1,680)
Balance, December 31, 2010	41,283
Net income	879
Distributions to Member	(2,966)
Balance, June 30, 2011 (Unaudited)	$ 39,196

ENTERPRISE ALABAMA INTRASTATE, LLC

NOTES TO FINANCIAL STATEMENTS

1. PARTNERSHIP ORGANIZATION

Enterprise Alabama Intrastate, LLC ("Alabama Intrastate") is a Delaware limited liability company formed in December 2002 that owns an intrastate natural gas pipeline system located in Alabama. Unless the context requires otherwise, references to "we," "us," "our" or "the Company" within these notes are intended to mean Alabama Intrastate. At December 31, 2010 and June 30, 2011, we were owned 100% by Enterprise GTM Holdings L.P. ("Enterprise"), which is a subsidiary of Enterprise Products Operating LLC ("EPO"). Enterprise is referred to as our "Member" within these financial statements.

Our business activities include gathering, transporting, purchasing and selling natural gas in Alabama. Our natural gas pipeline system consists of 388-miles of gathering and transportation pipelines, which access conventional gas and coal bed methane gas reserves located in the Black Warrior supply basin of Alabama. Our natural gas pipeline system has a gathering and transportation capacity of 250 billion British thermal units per day ("BBtus/d").

Our operations are subject to various state and federal regulations, including regulations promulgated by the Federal Energy Regulatory Commission ("FERC").

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our financial statements are prepared on the accrual basis of accounting in accordance with U.S. generally accepted accounting principles ("GAAP"). Our financial statements were prepared from the separate records maintained by EPO and may not necessarily be indicative of the conditions that would have existed or the results of operations if we had operated as an unaffiliated entity. Transactions between EPO and us have been identified in our financial statements as transactions between affiliates. Except as noted within the context of each footnote disclosure, dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars. Our net income and comprehensive income amounts are the same; therefore, our statements of income only present net income.

Cash and Cash Equivalents Alabama Intrastate operates within EPO's cash management program. As a result, all of Alabama Intrastate's cash receipts and payments with third parties and affiliates are transacted by EPO on behalf of Alabama Intrastate and charged to an intercompany account. At each reporting date, the balance of this account is charged to equity and reflected as a distribution of cash effectively to our Member. See Note 4 for information regarding Member's equity.

Current Assets and Current Liabilities We present, as individual captions in our balance sheets, all components of current assets and current liabilities that exceed 5% of total current assets and liabilities, respectively.

Business Segment We have one business segment, Natural Gas Pipelines & Services, which consists of the gathering and transportation of natural gas and related marketing activities. The following table summarizes our revenues and long-lived assets for this business segment at the date and for the period indicated:

	December 31, 2010	June 30, 2011 (Unaudited)
Segment assets	$ 44,551	$ 41,772

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ENTERPRISE ALABAMA INTRASTATE, LLC

NOTES TO FINANCIAL STATEMENTS (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

	For the Year Ended December 31, 2010	For the Six Months Ended June 30, 2010	2011
		(Unaudited)	
Segment revenues	$ 42,871	$ 22,561	$ 19,120
Segment operating income	2,078	1,320	879
Segment net income	2,078	1,320	879

Contingencies Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. We had no contingent liabilities as of December 31, 2010 or June 30, 2011.

Environmental Costs Our operations include activities subject to federal and state environmental regulations. Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. There were no environmental remediation liabilities incurred as of December 31, 2010 or June 30, 2011.

Estimates Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Any future changes in facts and circumstances may require updated estimates, which, in turn, could have a significant impact on our financial statements.

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ENTERPRISE ALABAMA INTRASTATE, LLC

NOTES TO FINANCIAL STATEMENTS (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Fair Value Information Accounts receivable, accounts payable, accrued gas payables and other current liabilities are carried at amounts which reasonably approximate their fair values due to their short-term nature.

Impairment Testing for Long-Lived Assets Long-lived assets such as property, plant and equipment are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset's carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's-length transaction. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques.

No asset impairment charges were recognized during the year ended December 31, 2010 or six months ended June 30, 2011. The carrying value of our long-lived assets was recoverable through future undiscounted cash flows.

Income Taxes We are organized as a pass-through entity for federal income tax purposes and our Member is responsible for its share of our taxable income for federal income tax purposes. As a result, our financial statements do not provide for such taxes.

Natural Gas Imbalances In the natural gas pipeline transportation business, volumetric imbalances frequently result from differences in natural gas received from and delivered to customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. As of December 31, 2010 and June 30, 2011, we had natural gas imbalance receivables of $299 thousand and $258 thousand, respectively, which are reflected as a component of "Accounts receivable trade" on our Balance Sheets. We value natural gas imbalance amounts at a current month industry index price.

Property, Plant and Equipment Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of operations for the respective period. Depreciation is recorded over the estimated useful lives of the related assets using the straight-line method for financial statement purposes. See Note 3 for additional information regarding our property, plant and equipment.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the

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ENTERPRISE ALABAMA INTRASTATE, LLC

NOTES TO FINANCIAL STATEMENTS (Continued)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts. Our ARO assets and liabilities were immaterial at December 31, 2010 and June 30, 2011. Based on information currently available, we estimate that accretion expense will approximate $2 thousand annually for 2011 through 2013 and $3 thousand for 2014 and 2015.

Revenue Recognition In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectability is reasonably assured. Utilizing these criteria, revenues are generally recognized when services are rendered.

Our natural gas marketing activities generate revenue from the sale and delivery of natural gas purchased from third parties on the open market. Revenue from these sales contracts is recognized when the natural gas is delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

We generate revenues from gathering and transportation agreements in which shippers are billed a fee per unit of volume gathered and transported (typically per million British thermal units) multiplied by the volume gathered or delivered. Revenue from these contracts is recognized when the natural gas is delivered to customers. These fees are either contractual or regulated by governmental agencies, including the FERC.

Subsequent Events We have evaluated subsequent events through October 31, 2011, which is the date our Audited Financial Statements and Notes were available to be issued. See Note 8 for information regarding the sale of Alabama Intrastate to Southcross on August 31, 2011.

3. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation were as follows at the date indicated:

	Estimated Remaining Useful Life at December 31, 2010	December 31, 2010	June 30, 2011
Pipeline	28 years	$ 47,374	$ 47,383
Transportation equipment	1 - 5 years	678	679
Land		48	48
Construction in progress			51
Total		48,100	48,161
Less accumulated depreciation		9,239	9,974
Property, plant and equipment, net		$ 38,861	$ 38,187

Depreciation expense was $1.5 million for the year ended December 31, 2010 and $739 thousand and $734 thousand for the six months ended June 30, 2010 and 2011, respectively.

ENTERPRISE ALABAMA INTRASTATE, LLC

NOTES TO FINANCIAL STATEMENTS (Continued)

3. PROPERTY, PLANT AND EQUIPMENT (Continued)

Certain producers have options to purchase our Blue Creek West and White Oak Creek compressor stations from us at mutually agreeable buyout amounts, not to exceed the net book carrying value of these assets. The net book carrying values of the Blue Creek West and White Oak Creek compressor stations were $4.0 million and $11.0 million, respectively, at December 31, 2010. At June 30, 2011, the net book carrying values of the Blue Creek West and White Oak Creek compressor stations were $3.9 million and $10.7 million, respectively.

4. MEMBER'S EQUITY

As a limited liability company, our Member is not liable for any of our obligations or liabilities. We paid cash distributions to our Member of $1.8 million, $1.8 million and $3.0 million for the year ended December 31, 2010 and six months ended June 30, 2010 and 2011, respectively, through our cash management program with EPO (see "Cash and Cash Equivalents" included under Note 2).

5. RELATED PARTY TRANSACTIONS

The following table presents our related party transactions for the periods presented:

	For the Year Ended December 31, 2010	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2011
		(Unaudited)	(Unaudited)
Revenues from EPO:			
Natural gas sales	$ 5,000	$ 1,438	$ 605
Cost and expenses with EPO and affiliates:			
Cost of natural gas sales	$ 994	$ 994	$
Other operating costs and expenses	1,755	912	966
General and administrative costs	467	193	214
Total related party costs and expenses	$ 3,216	$ 2,099	$ 1,180

We sell and purchase natural gas from EPO at market-based rates. EPO accounted for 12%, 6% and 3% of our revenues for the year ended December 31, 2010 and the six months ended June 30, 2010 and 2011, respectively. Our receivables from this affiliate related to natural gas sales were $1.2 million and $201 thousand at December 31, 2010 and June 30, 2011, respectively.

We have no employees. All of our operating functions are provided by employees of affiliates of EPO. During the year ended December 31, 2010 and the six months ended June 30, 2010 and 2011, our related party expenses with EPO and its affiliates for such operating services were $1.3 million, $692 thousand and $670 thousand, respectively. Likewise, our general and administrative support services are provided by EPO and its affiliates. Our related party expenses for these services were $467 thousand, $193 thousand and $214 thousand for the year ended December 31, 2010 and the six months ended June 30, 2010 and 2011, respectively. In general, such costs are allocated either (i) on an actual basis for direct expenses EPO incurs on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of costs based on the estimated use of such services by us (e.g., the allocation of legal or accounting salaries based on estimates of time spend on our business and affairs).

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ENTERPRISE ALABAMA INTRASTATE, LLC

NOTES TO FINANCIAL STATEMENTS (Continued)

5. RELATED PARTY TRANSACTIONS (Continued)

Since the vast majority of expenses charges to us are on an actual basis (i.e., no mark-up or subsidy is charged or received by EPO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

6. COMMITMENTS AND CONTINGENCIES

Regulatory and Legal In the ordinary course of business, we are subject to various laws and regulations. In the opinion of management, compliance with existing laws and regulations will not materially affect our financial position, results of operations, or cash flows. Also, in the normal course of business, we may be a party to lawsuits and similar proceedings before various courts and governmental agencies involving, for example, contractual disputes, environmental issues and other matters. We are not aware of any such matters at December 31, 2010 or June 30, 2011. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Contractual Obligations The following table summarizes our product purchase commitments at December 31, 2010:

	Payment or Settlement due by Period		
	Total	**2011**	**2012**
Product purchase commitments:			
Estimated payment obligations:			
Natural gas	$ 21,314	$ 13,139	$ 8,175
Underlying major volume commitments:			
Natural gas (in BBtus)(1)	5,063	3,121	1,942

(1) Volume is measured in BBtus.

We have long and short-term product purchase obligations for natural gas with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our estimated payment obligations and volume commitments under these contracts for the years presented. There were no material changes in our product purchase commitments during the six months ended June 30, 2011.

At December 31, 2010 and June 30, 2011, we did not have any significant contractual payment obligations in connection with third-party service arrangements or unconditional payment obligations to vendors for products to be delivered in connection with capital projects.

7. SIGNIFICANT RISKS

Credit Risk Due to Industry Concentrations A substantial portion of our revenues are derived from companies in the domestic natural gas industry. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other regional conditions. We generally do not require collateral for our accounts receivable; however, we do attempt

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ENTERPRISE ALABAMA INTRASTATE, LLC

NOTES TO FINANCIAL STATEMENTS (Continued)

7. SIGNIFICANT RISKS (Continued)

to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

Our largest non-affiliated customers are Alabama Gas Corporation ("Alagasco") and El Paso Corporation ("El Paso"), which accounted for 64% and 10%, respectively, of our revenues during the year ended December 31, 2010. Alagasco is the largest natural gas distributor in Alabama and serves approximately 437,000 customers in over 200 Alabama cities, towns and communities. El Paso provides natural gas and related energy products and is one of North America's largest independent natural gas producers.

Nature of Operations in Midstream Energy Industry Our operations are within the midstream energy industry, which includes the marketing, gathering and transporting of natural gas. A reduction in demand for natural gas for heating and gas-fired power generation purposes, whether because of general economic conditions; reduced demand by customers; increased competition from other products due to pricing differences; adverse weather conditions; government regulations affecting energy commodity prices; or other reasons, could adversely affect our financial position, results of operations and cash flows.

8. SUBSEQUENT EVENT

Subsequent to December 31, 2010, Enterprise's management made the decision to sell Alabama Intrastate. On August 15, 2011, Enterprise and Southcross Alabama Gathering System, L.P. ("Southcross") executed a purchase agreement whereby Southcross acquired all of the equity interests of Alabama Intrastate for $21 million of cash consideration. The transaction closed on August 31, 2011.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To Southcross Energy Partners GP, LLC, as general partner of Southcross Energy Partners, L.P.:

We have audited the accompanying balance sheet of Southcross Energy Partners, L.P. (the "Partnership") as of April 19, 2012. The balance sheet is the responsibility of the Partnership's management. Our responsibility is to express an opinion on the balance sheet based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether 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 audit 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 audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet presents fairly, in all material respects, the financial position of the Partnership as of April 19, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Dallas, Texas
April 20, 2012

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SOUTHCROSS ENERGY PARTNERS, L.P.

BALANCE SHEET

APRIL 19, 2012

ASSETS		
Current Assets		
Cash	$	1,000
Total assets	$	1,000
LIABILITIES AND PARTNERS' EQUITY		
COMMITMENTS AND CONTINGENCIES		
Limited partner's interest	$	980
General partner's interest		20
TOTAL LIABILITIES AND PARTNERS' EQUITY	$	1,000

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SOUTHCROSS ENERGY PARTNERS, L.P.

NOTE TO BALANCE SHEET

1. Nature of Operations

Southcross Energy Partners, L.P. (the "Partnership") is a Delaware limited partnership formed on April 12, 2012 to acquire certain assets and related contracts and agreements from the operating subsidiaries of Southcross Energy LLC. In order to simplify the Partnership's obligations under the laws of selected jurisdictions in which the Partnership will conduct business, the Partnership's activities will be conducted through a wholly owned limited liability company.

Southcross Energy Partners GP, LLC, as general partner, contributed $20 and Southcross Energy LLC, as the organizational limited partner, contributed $980 to the Partnership on April 19, 2012. There have been no other transactions involving the Partnership as of April 20, 2012.

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APPENDIX A
FIRST AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF SOUTHCROSS ENERGY PARTNERS, L.P.

[To be filed by Amendment.]

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APPENDIX B
GLOSSARY OF TERMS

Bbls/d or Bbl/d: Barrels per day or barrel per day.

condensate: A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Core historic pipeline area: A 13-county area in South Texas consisting of Aransas, Bee, DeWitt, Duval, Ft. Bend, Jackson, Jim Wells, Karnes, Nueces, Refugio, San Patricio, Victoria and Wharton counties.

dry gas: A gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.

Eagle Ford Southcross pipeline catchment area: A seven county area in South Texas located in or close proximity to the Eagle Ford shale area consisting of Bee, DeWitt, Karnes, La Salle, Live Oak, McMullen and Webb counties.

gal: One gallon.

gal/d: One gallon per day.

Mcf: One thousand cubic feet.

Mgal: One thousand gallons.

MMBtu: One million British Thermal Units.

MMBtu/d: One million British Thermal Units per day.

MMcf: One million cubic feet.

MMcf/d: One million cubic feet per day.

NGLs: Natural gas liquids. The combination of ethane, propane, normal butane, iso-butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

OPIS: Oil Price Information Service.

play: A proven geological formation that contains commercial amounts of hydrocarbons.

POP: Percent-of-proceeds.

psig: Pound per square inch. It is the pressure resulting from a force of one pound-force applied to an area of one square inch.

receipt point: The point where production is received by or into a gathering system or transportation pipeline.

residue gas: The natural gas remaining after being processed or treated.

tailgate: Refers to the point at which processed natural gas and natural gas liquids leave a processing facility for market.

Tcf: One trillion cubic feet.

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throughput volume: The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.

TRRC: Texas Railroad Commission.

wellhead: The equipment at the surface of a well that is used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground.

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Common Units

Representing Limited Partner Interests

Southcross Energy Partners, L.P.

Joint Book-Running Managers

Citigroup **Wells Fargo Securities**

Until , 2012 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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PART II

INFORMATION NOT REQUIRED IN THE PROSPECTUS

Item 13. ***Other Expenses of Issuance and Distribution.***

Set forth below are the expenses (other than underwriting discounts, commissions and structuring fees) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the SEC registration fee, the FINRA filing fee and the NYSE listing fee, the amounts set forth below are estimates.

SEC registration fee	$ 26,358
FINRA filing fee	23,500
NYSE listing fee	*
Fees and expenses of legal counsel	*
Accounting fees and expenses	*
Transfer agent and registrar fees	*
Miscellaneous	*
Total	*

*
To be filed by amendment.

Item 14. ***Indemnification of Directors and Officers.***

Southcross Energy Partners, L.P.

Subject to any terms, conditions or restrictions set forth in the partnership agreement, Section 17-108 of the Delaware Revised Uniform Limited Partnership Act empowers a Delaware limited partnership to indemnify and hold harmless any partner or other person from and against any and all claims and demands whatsoever. The section of the prospectus entitled "The Partnership Agreement Indemnification" discloses that we will generally indemnify officers, directors and affiliates of our general partner to the fullest extent permitted by the law against all losses, claims, damages or similar events and is incorporated herein by reference.

The underwriting agreement to be entered into in connection with the sale of the securities offered pursuant to this registration statement, the form of which will be filed as an exhibit to this registration statement, provides for indemnification of Southcross Energy Partners, L.P. and our general partner, their officers and directors, and any person who controls our general partner, including indemnification for liabilities under the Securities Act.

Southcross Energy Partners GP, LLC

Subject to any terms, conditions or restrictions set forth in the limited liability company agreement, Section 18-108 of the Delaware Limited Liability Company Act empowers a Delaware limited liability company to indemnify and hold harmless any member or manager or other person from and against any and all claims and demands whatsoever.

Under the limited liability agreement of our general partner, in most circumstances, our general partner will indemnify the following persons, to the fullest extent permitted by law, from and against any and all losses, claims, damages, liabilities (joint or several), expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings (whether civil, criminal, administrative or investigative):

any person who is or was an affiliate of our general partner (other than us and our subsidiaries);

any person who is or was a member, partner, officer, director, employee, agent or trustee of our general partner or any affiliate of our general partner;

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any person who is or was serving at the request of our general partner or any affiliate of our general partner as an officer, director, employee, member, partner, agent, fiduciary or trustee of another person; and

any person designated by our general partner.

Our general partner will purchase insurance covering its officers and directors against liabilities asserted and expenses incurred in connection with their activities as officers and directors of our general partner or any of its direct or indirect subsidiaries.

Item 15. Recent Sales of Unregistered Securities.

On April 12, 2012, in connection with the formation of Southcross Energy Partners, L.P., we issued (i) the 2.0% general partner interest in us to our general partner for $20.00 and (ii) the 98.0% limited partner interest in us to Southcross Energy LLC for $980.00, in each case, in an offering exempt from registration under Section 4(2) of the Securities Act.

There have been no other sales of unregistered securities within the past three years.

Item 16. Exhibits and Financial Schedules.

The following documents are filed as exhibits to this registration statement:

Number	Description
1.1*	Form of Underwriting Agreement
3.1	Certificate of Limited Partnership of Southcross Energy Partners, L.P.
3.2	Agreement of Limited Partnership of Southcross Energy Partners, L.P.
3.3*	Form of Amended and Restated Agreement of Limited Partnership of Southcross Energy Partners, L.P. (included as Appendix A to the prospectus)
3.4	Certificate of Formation of Southcross Energy Partners GP, LLC
3.5	Limited Liability Company Agreement of Southcross Energy Partners GP, LLC
5.1*	Form of opinion of Latham & Watkins LLP as to the legality of the securities being registered
8.1*	Form of opinion of Latham & Watkins LLP relating to tax matters
10.1*	Form of Amended and Restated Credit Agreement
10.2	Form of Long-Term Incentive Plan
10.3*	Form of Contribution, Conveyance and Assumption Agreement
10.4	Amended and Restated Credit Agreement dated as of June 10, 2011 among Southcross Energy LLC as borrower, Wells Fargo Bank, N.A., as Administrative Agent, BVA Compass and Suntrust Bank, as Co-Syndication Agents, Citibank, N.A. and U.S. Bank National Association, as Co-Documentation Agents and the Lenders party thereto
21.1	List of Subsidiaries of Southcross Energy Partners, L.P.
23.1	Consent of Deloitte & Touche LLP Dallas, Texas office
23.2	Consent of Deloitte & Touche LLP Houston, Texas office
23.3*	Form of consent of Latham & Watkins LLP (contained in Exhibit 5.1)
23.4*	Form of consent of Latham & Watkins LLP (contained in Exhibit 8.1)
24.1	Powers of Attorney

* To be filed by amendment.

Previously filed as an exhibit to the Registration Statement (Registration No. 333-180841).

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Item 17. Undertakings

The undersigned registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) That, for the purpose of determining liability under the Securities Act of 1933 to any purchaser, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness. Provided, however, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use.

(4) That, for the purpose of determining liability of the registrant under the Securities Act of 1933 to any purchaser in the initial distribution of the securities, the undersigned registrant undertakes that in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(i) Any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

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(iii) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and

(iv) Any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.

The undersigned registrant undertakes to send to each common unitholder, at least on an annual basis, a detailed statement of any transactions with Southcross Energy Partners GP, LLC, our general partner, or its affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to Southcross Energy Partners GP, LLC or its affiliates for the fiscal year completed, showing the amount paid or accrued to each recipient and the services performed.

The undersigned registrant undertakes to provide to the common unitholders the financial statements required by Form 10-K for the first full fiscal year of operations of the company.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Dallas, State of Texas, on July 13, 2012.

Southcross Energy Partners, L.P.

By: Southcross Energy Partners GP, LLC
its general partner

By: /s/ David W. Biegler

Name: David W. Biegler
Title: Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, as amended this Registration Statement has been signed by the following persons in the capacities and the dates indicated.

Signature	Title	Date
/s/ David W. Biegler David W. Biegler	Chief Executive Officer (Principal Executive Officer) and Director	July 13, 2012
* J. Michael Anderson	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	July 13, 2012
* David M. Mueller	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	July 13, 2012
* Samuel P. Bartlett	Director	July 13, 2012
* Jon M. Biotti	Director	July 13, 2012
* Kim G. Davis	Director	July 13, 2012
* Jerry W. Pinkerton	Director	July 13, 2012

*By: /s/ David W. Biegler

David W. Biegler
Attorney-in-Fact

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EXHIBIT INDEX

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To be filed by amendment.

Previously filed as an exhibit to the Registration Statement (Registration No. 333-180841).