As filed with the Securities and Exchange Commission on January 21, 2014

Registration No. 333-192542

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

Amendment No. 1
to
FORM S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

ENABLE MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	4922	72-1252419
(State or jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

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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. ☐

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

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. ☐

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. ☐

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

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

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 or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. We may not offer or sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

PROSPECTUS
Subject To Completion, dated January 21, 2014

ENABLE™
MIDSTREAM PARTNERS

Common Units
Representing Limited Partner Interests

This is the initial public offering of common units of Enable Midstream Partners, LP. All of the common units are being sold by us. We currently estimate 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 applied to list our common units on the New York Stock Exchange under the symbol "ENBL."

Investing in our common units involves risks. Please see "Risk Factors" beginning on page 25.

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 and its affiliates, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.*
- *Our contracts are subject to renewal risks.*
- *Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect our results of operations and our ability to make cash distributions to unitholders.*
- *Our general partner and its affiliates, including OGE Energy and CenterPoint Energy, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.*
- *Our partnership agreement restricts the remedies available to holders of our common units for 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 will not initially be able to remove our general partner without its consent.*
- *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.*
- *Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service, or IRS, were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our distributable cash flow to our unitholders would be substantially reduced.*
- *Our unitholders' share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.*

	Per Common Unit	Total
Initial public offering price	$	$
Underwriting discounts and commissions	$	$
Proceeds, before expenses, to Enable Midstream Partners, LP	$	$

We have granted the underwriters a 30-day option to purchase up to an additional common units from us on the same terms and conditions as set forth above if the underwriters sell more than common units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units to purchasers on or about , 2014, through the book-entry facilities of The Depository Trust Company.

Morgan Stanley *Barclays* *Goldman, Sachs & Co.*

Prospectus dated , 2014

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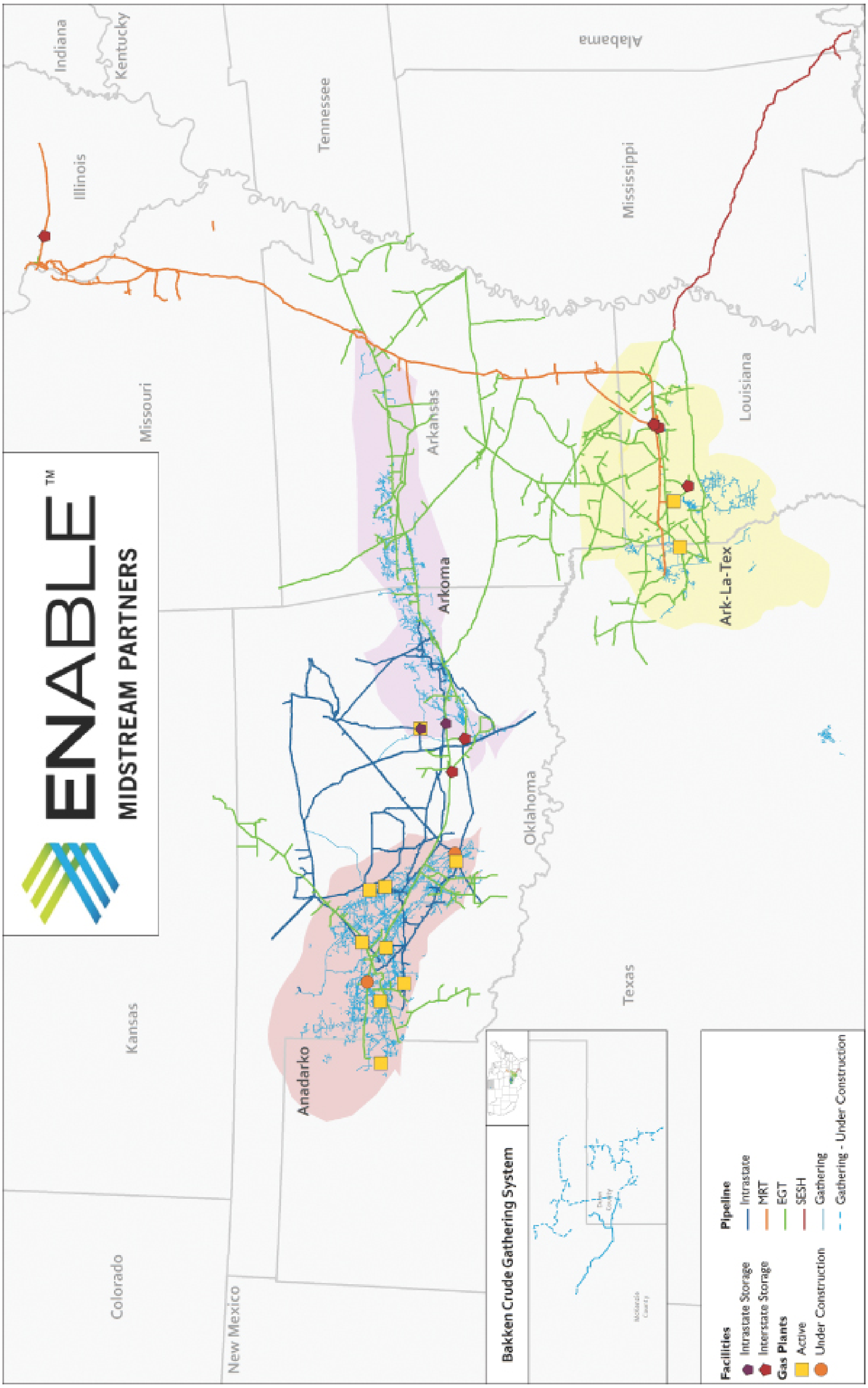

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You should rely only on the information contained in this prospectus or in any free writing prospectus we may authorize to be delivered to you. Neither we nor the underwriters have authorized anyone to provide you with additional or different information. 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 an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

INDUSTRY AND MARKET DATA

The data included in this prospectus regarding the midstream natural gas and crude oil industry, including descriptions of trends in the market and our position and the position of our competitors within the industry, is based on a variety of sources, including independent industry publications, government publications and other published independent sources, information obtained from customers, distributors, suppliers and trade and business organizations and publicly available information, as well as our good faith estimates, which have been derived from management's knowledge and experience in the industry in which we operate. Although we have not independently verified the accuracy or completeness of the third-party information included in this prospectus, based on management's knowledge and experience, we believe that the third-party sources are reliable and that the third-party information included in this prospectus or in our estimates is accurate and complete.

SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the historical combined and consolidated financial statements, the pro forma combined financial statements and the related notes included elsewhere herein before investing in our common units. Unless indicated otherwise, the information presented in this prospectus assumes (1) an initial public offering price of $ per common unit and (2) that the underwriters do not exercise their option to purchase additional common units. You should read "Risk Factors" beginning on page 25 for more information about important risks that you should consider carefully before investing in our common units. We include a glossary of some of the terms used in this prospectus as Appendix B.

Except as otherwise set forth in the prospectus, all references in this prospectus to "our," "we," the "partnership," "us" and like terms, when used with respect to periods prior to May 1, 2013, refer to the entities comprising CenterPoint Energy's interstate pipelines and field services reportable business segments, and when used with respect to periods on and after May 1, 2013, refer to Enable Midstream Partners, LP and its subsidiaries. For a description of the transactions entered into in connection with the formation of our partnership on May 1, 2013, please read "—Formation Transactions and Partnership Structure." References to "Enable GP" or our "general partner" are to Enable GP, LLC, a Delaware limited liability company and our general partner; references to "CenterPoint Energy" are to CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries, other than us; references to "OGE Energy" are to OGE Energy Corp., an Oklahoma corporation, and its subsidiaries, other than us; references to our "sponsors" are to CenterPoint Energy and OGE Energy; and references to "ArcLight" are to ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities, ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., and Bronco Midstream Partners, L.P., and their respective general partners and subsidiaries.

ENABLE MIDSTREAM PARTNERS, LP

Our Business

We are a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. We serve key current and emerging production areas in the United States, including several premier shale resource plays and local and regional end-user markets in the United States. Our assets and operations are organized into two business segments: (i) gathering and processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. In both business segments, we generate a substantial portion of our gross margin under long-term, fee-based agreements that minimize our direct exposure to commodity price fluctuations.

Our natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments, which we refer to as unconventional shale resource plays, in some of the most productive regions of the Anadarko, Arkoma and Ark-La-Tex basins. These basins have experienced a strong increase in investment and drilling activity by exploration and production companies in recent years. We also own an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. We are continuing to construct additional crude oil gathering capacity in this area. Our natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Upon our formation in May 2013 as a limited partnership among OGE Energy, CenterPoint Energy and ArcLight, we became one of the largest midstream partnerships in the United States based on total assets. As of September 30, 2013, our portfolio of energy infrastructure assets included approximately 11,000 miles of gathering pipelines, 11 major processing plants with approximately 1.9 Bcf/d of processing capacity, approximately 7,800 miles of interstate pipelines (including Southeast Supply Header, LLC, or SESH), approximately 2,300 miles of intrastate pipelines and eight storage facilities comprising 86.5 Bcf of storage capacity. We believe our scale benefits our customers by providing them with fully integrated midstream services and improved access from the wellhead to the marketplace. In addition, we believe our scale and scope will position us to be more competitive in developing new energy infrastructure assets and adding complementary services and business lines.

From the year ended December 31, 2010 through the nine month period ended September 30, 2013, on a pro forma basis, we grew the volume of natural gas gathered on our systems by 17%. Over the same time period, the volume of gas processed on our systems grew by 49% on a pro forma basis. We expect to continue to grow our business by providing midstream services to our customers' rapidly growing upstream development projects. We expect our customers' activity in the basins in which we operate to result in higher throughput on our systems and additional organic growth opportunities to expand the capacity and utilization of our assets. We also expect to grow our business and distributable cash flow by developing new energy infrastructure projects to support new and existing customers as they expand beyond our current footprint, as well as through third-party acquisitions. For the years ended December 31, 2011 and 2012, on a pro forma basis, we invested $831 million and $912 million, respectively, in expansion capital expenditures. During the nine months ended September 30, 2013, on a pro forma basis, we invested $405 million in expansion capital expenditures. We expect that our expansion capital expenditures will be $448 million for the year ending December 31, 2014.

We believe that our contractual arrangements provide a strong platform to support established operations and future organic growth. For the nine months ended September 30, 2013, on a pro forma basis, approximately 75% of our gross margin was generated from contracts that are fee-based, and approximately 50% of our gross margin was attributable to firm contracts or contracts with minimum volume commitment features.

For the nine months ended September 30, 2013, on a pro forma basis, we generated $984 million of gross margin, $586 million of Adjusted EBITDA and $338 million of net income. Gross margin and Adjusted EBITDA are non-GAAP financial measures. For definitions of gross margin and Adjusted EBITDA and a reconciliation to their most directly comparable financial measures calculated in accordance with generally accepted accounting principles in the United States, or GAAP, please read "—Summary Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures."

Gathering and Processing. We provide gathering, processing, treating, compression, dehydration and natural gas liquids (NGLs) fractionation for natural gas producers. Our gathering and processing assets are strategically located in established and actively developing basins in the United States and are interconnected with our interstate and intrastate pipelines and with third-party pipelines, which provides our customers with the benefits of a flexible and efficient transportation and storage system. On a pro forma basis for the nine months ended September 30, 2013, our top customers by volumes gathered were affiliates of Encana Corporation (Encana), Shell Oil Corporation (Shell), Exxon Mobil Corporation (Exxon), Chesapeake Energy Corporation (Chesapeake), Apache Corporation (Apache), Continental Resources, Inc. (Continental), QEP Energy Company (QEP), Devon Energy Production Company LP (Devon), BP America Production Company (BP) and Samson Resources Company (Samson).

The following table sets forth certain information regarding our gathering and processing assets on a pro forma basis as of or for the nine months ended September 30, 2013:

Asset/Basin	Length (miles)	Compression (Horsepower)	Average Gathering Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (Bbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	6,550	594,500	1.3	8	1,245	42,700	4.7
Arkoma Basin	2,700	115,600	1.0	1	60	4,700	1.2
Ark-La-Tex Basin[(1)]	1,600	182,900	1.3	2	545	10,900	0.7
Total	10,850	893,000	3.6	11	1,850	58,300	6.6

(1) Ark-La-Tex basin assets also include 14,500 Bbl/d of fractionation capacity and 6,300 Bbl/d of ethane pipeline capacity, which are not listed in the table.

Five of our processing plants in the Anadarko basin are interconnected via our large-diameter, rich gas gathering system in western Oklahoma, which spans 18 counties and has approximately 1.0 Bcf/d of processing capacity. Our 4.7 million gross acres of acreage dedications in the Anadarko basin area are served by this system, which we refer to as our “super-header” system. We have configured this system to optimize the flow of natural gas and the utilization of the processing plants connected to it, which we believe provides us with strategic growth opportunities. We have made investments to expand the super-header system and continue to grow its capacity through the planned addition of two new cryogenic processing plants and related gathering pipelines. One of these two new plants, which is located in Custer County, Oklahoma (the McClure Plant), will increase our natural gas processing capacity in the basin by over 15%, providing an additional 200 MMcf/d of natural gas processing capacity. The McClure Plant is expected to be completed in the first quarter of 2014. The other new plant, which will be located in Grady County, Oklahoma (the Bradley Plant), will provide an additional 200 MMcf/d of processing capacity and is expected to be completed in the first quarter of 2015.

We believe our contract structures provide us with stable cash flows in our major operating basins. For the nine months ended September 30, 2013, on a pro forma basis, we generated 60% of our gathering and processing gross margin under long-term, fee-based agreements, and of this fee-based margin, approximately 38% was attributable to gathering and processing contracts containing minimum volume commitment features. Under our minimum volume commitment contracts, our customers commit to ship a minimum annual volume of natural gas on our gathering system, or, in lieu of shipping such volumes, to pay us periodically as if that minimum amount had been shipped. As of September 30, 2013, we had minimum volume commitments in lean natural gas developments of 1.6 Bcf/d with a weighted average remaining term of over nine years. We also have an emerging crude oil gathering business in the Bakken shale formation with a similar minimum volume commitment contract structure that we believe will provide us with an additional source of stable cash flows. Under our acreage dedication contracts, our customers are generally required to deliver all of their production within the dedicated area to our gathering system for processing over the period of the contract. As of September 30, 2013, we had acreage dedications in rich natural gas developments covering more than 5.7 million acres that generally have long lived reserves with a weighted average remaining term of approximately nine years. As of September 30, 2013, our gathering and processing contracts for our top ten natural gas producer customers, which accounted for approximately 75% of our gathered volumes for the nine months ended September 30, 2013, on a pro forma basis, had a volume-weighted average remaining term of approximately nine years.

For the nine months ended September 30, 2013, on a pro forma basis, our gathering and processing business segment generated $560 million of gross margin and $338 million of Adjusted EBITDA.

Transportation and Storage. Our natural gas transportation and storage business segment consists of our interstate pipelines, our intrastate pipelines and our storage assets. We provide pipeline takeaway capacity for natural gas producers from supply basins to market hubs and critical natural gas supply for industrial end users and utilities, such as local distribution companies, or LDCs, and power generators. Our interstate pipeline system, including SESH, includes approximately 7,800 miles of transportation pipelines and extends from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois. Our eight storage facilities in Oklahoma, Louisiana and Illinois have 86.5 Bcf of storage capacity and strategically complement our pipeline systems.

The following table sets forth certain information regarding our transportation and storage assets as of September 30, 2013:

Asset	Length (miles)	Capacity	Total Firm Contracted Capacity(Bcf/d)	Average Throughput Volume (Tbtu/d)	Percent of Capacity under Firm Contracts	Weighted Average Remaining Firm Contract Life(years)
Interstate Transportation(1)	7,800	8.4 Bcf/d	7.2	3.5(2)	86%	4.1
Intrastate Transportation	2,300	1.9 Bcf/d(3)	—	1.6	—	5.4
Storage	—	86.5 Bcf	67.9	—	79%	4.7

(1) Except with respect to length, this information does not include amounts for SESH. SESH is a non-consolidated entity in which we own a 24.95% ownership interest.

(2) Actual volumes transported per day may be less than total firm contracted capacity based on demand.

(3) This represents the maximum single day receipts on the intrastate systems. Our Oklahoma intrastate pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits our ability to determine an overall system capacity. During the nine months ended September 30, 2013, the peak daily throughput was 1.9 TBtu or, on a volumetric basis, 1.9 Bcf/d.

We generate revenue primarily by charging demand fees pursuant to applicable tariffs for the transportation and storage of natural gas on our system. We generate 96% of our transportation and storage gross margin under fee-based agreements with a weighted average remaining contract life of approximately five years as of September 30, 2013. Demand-based margin for this period represented 89% of the fee-based margin. We generally do not take ownership of the natural gas that we transport and store.

For the nine months ended September 30, 2013, on a pro forma basis, our top customers by gross margin were affiliates of CenterPoint Energy, Laclede Group (Laclede), Exxon, OGE Energy and American Electric Power Company, Inc. (AEP). Our transportation and storage assets were designed and built to serve affiliates of CenterPoint Energy, Laclede, OGE Energy and AEP and are competitively positioned to serve other large natural gas and electric utility companies, such as Ameren Corporation (Ameren) and Entergy Corporation (Entergy).

For the nine months ended September 30, 2013, on a pro forma basis, our transportation and storage business segment generated $426 million of gross margin and $248 million of Adjusted EBITDA.

Business Strategies

Our primary business objective is to practice operational excellence and to grow our business responsibly, enabling us to increase the amount of cash distributions we make to our unitholders over time while maintaining our financial stability. We intend to accomplish this objective by executing the strategies listed below:

- *Capitalize on Organic Growth Opportunities Associated with Our Strategically Located Assets.* We own and operate assets servicing four of the largest basins in the United States, including some of the most productive shale developments in these basins. We believe current high levels of natural gas and crude oil exploration, development and production activities within our areas of operation present significant opportunities for organic growth and increasing throughput on our system. Over 200 drilling rigs were deployed in our areas of operation as of September 30, 2013, which represents a 12% increase over December 2012. As a result of this expanding activity, we are constructing two processing facilities in Oklahoma that are expected to provide an additional combined 400 MMcf/d in processing capacity. We are currently evaluating other expansion opportunities to further enhance our existing systems.
- *Continue to Minimize Direct Commodity Price Exposure Through Long-Term, Fee-Based Contracts.* We continually seek ways to minimize our exposure to commodity price risk, and we believe that our focus on fee-based revenues reduces our direct commodity price exposure and is essential to maintaining stable cash flows and increasing our quarterly distributions over time. Since 2009, we have focused on increasing the percentage of long-term, fee-based contracts with our customers. For the nine months ended September 30, 2013, on a pro forma basis, 75% of our gross margin was generated from fee-based contracts. As we grow, we intend to maintain our focus on long-term, fee-based contracts.
- *Maintain Strong Customer Relationships to Attract New Volumes and Expand Beyond Our Existing Asset Footprint and Business Lines.* We plan to grow our business through our strong relationships with existing customers. We believe that we have built a strong and loyal customer base through exemplary customer service and reliable project execution. We have invested in multiple organic growth projects in support of our existing and new customers. For example, in 2012, an existing customer invited us to participate in the construction of a gas gathering system in the Ark-La-Tex basin, and in 2013, a second customer invited us to develop a crude oil gathering system in the Williston basin. We expect to maintain and build relationships with key producers and suppliers to continue to attract new volumes and expansion opportunities.
- *Grow Through Accretive Acquisitions and Disciplined Development.* We plan to pursue accretive acquisitions of complementary assets that provide attractive potential returns in new operating regions or midstream business lines. From January 1, 2010 through September 30, 2013, on a pro forma basis, we have invested approximately $639 million in acquisitions of new assets (including our Waskom processing plant, Cordillera gathering system and Amoruso gathering system) and investments in joint ventures (including SESH), and we have invested an additional $160 million in expansion capital associated with these projects. We also have the ability to acquire CenterPoint Energy's remaining 25.05% interest in SESH by 2015. We will continue to analyze acquisition opportunities using disciplined financial and operating practices, including a process for evaluating and managing risks to cash distributions.
- *Leverage the Scale of Our Existing Assets to Realize Significant Synergies.* Given the complementary features of our assets, we expect operating synergies from the interconnection and optimization of our systems to increase our cash flows over time. We expect to achieve operational and commercial synergies of $12.5 million through December 31, 2014, net of integration costs, and we expect additional synergies over time as we create a combined midstream service platform and are able to offer new and existing customers new and more efficient services.

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Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully because of the following competitive strengths:

- *Significant Capability, Scale and Stability of Our Diversified Midstream Business.* With approximately $11 billion in assets as of September 30, 2013 across ten states and multiple midstream business lines, we have an enhanced ability to provide customers with access to diverse services and end markets. We have approximately 11,000 miles of gathering pipelines and 11 major processing plants with approximately 1.9 Bcf/d of processing capacity spanning the Anadarko, Arkoma and Ark-La-Tex basins. Our natural gas processing plants produced 58.3 MBbl/d of NGLs, on a pro forma basis, for the nine months ended September 30, 2013, making us one of the largest producers of NGLs in the United States. Our network of interstate and intrastate pipelines covers approximately 7,800 miles (including SESH) and 2,300 miles, respectively, and is complemented by our 86.5 Bcf of storage capacity. We believe our size, scale and stability are competitive strengths and enhance our ability to provide reliable and increasing cash flows to our unitholders.
- *Strategically Located Assets that Provide a Strong Platform for Growth and Operational Flexibility to Our Customers.* Our assets are strategically configured in and around four of the most prominent natural gas and crude oil producing basins in the country and support a diversified midstream business that we believe will deliver reliable distributions and steady growth to our unitholders. Our assets transport natural gas to delivery points across the United States through 97 interconnects as of September 30, 2013. A portion of our system also serves local natural gas demand at LDCs, natural gas-fired power plants and industrial load in the regions in which we operate. We believe that our assets provide operational flexibility and delivery options for producers transporting natural gas from a mix of rich and lean natural gas plays to multiple market hubs within our region. Our assets also provide outlets for suppliers from other regions seeking to provide natural gas to on-system markets that we serve. We believe that our competitors would require significant capital expenditures to provide comparable services to these customers, providing us with a significant competitive advantage as demand for natural gas grows over time.
- *Strong Relationships with a Large and Diverse Customer Base.* We serve a broad range of customers across both of our business segments, and many of our customers rely on us for multiple midstream services. We believe that our track record of executing large infrastructure projects and meeting target in-service dates has allowed us to build a reputation as a reliable operator that provides high-quality services and focuses on the needs of our customers. On a pro forma basis for the nine months ended September 30, 2013, our top gathering and processing customers by volumes gathered were affiliates of Encana, Shell, Exxon, Chesapeake, Apache, Continental, QEP, Devon, BP and Samson and our top transportation and storage customers by gross margin were affiliates of CenterPoint Energy, Laclede, Exxon, OGE Energy and AEP. We believe that our relationships and reputation will continue to create opportunities with new and existing customers.
- *Stable Cash Flows as a Result of Fee-Based Revenues Under Long-Term Contracts.* For both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, we generated approximately 75% of our gross margin from fee-based contracts, primarily with creditworthy counterparties. We believe that our long-term, fee-based contracts, many of which include minimum volume commitments and/or acreage dedications, minimize our commodity price exposure and enhance the predictability of our financial performance.
- *Strong and Flexible Capital Structure.* We have a disciplined financial policy and maintain a strong and flexible capital structure to allow us to execute our identified growth projects and acquisitions even in challenging market environments. On May 1, 2013, we entered into our $1.4 billion five-year senior unsecured revolving credit facility, and we expect to have approximately $ million of available

borrowing capacity under this facility upon the closing of this offering. We believe our strong credit profile, including our investment-grade credit ratings, and the liquidity provided by our revolving credit facility give us a significant advantage over many of our competitors that may be more limited in their access to capital to pursue organic growth and acquisition opportunities.

- *Experienced Management Team and Key Operational Personnel with a Proven Record of Asset Operation, Acquisition, Construction, Development and Integration Expertise.* Our management team has an average of over years of experience in the energy industry in operating, acquiring, constructing, developing and integrating midstream assets, and understands the service requirements of our customers. Our management team has established strong relationships with producers, marketers and other end-users of natural gas throughout the U.S. upstream and midstream industries, which we believe will be beneficial to us in pursuing acquisition and organic expansion opportunities. We also employ skilled engineering, construction and operations teams that have significant experience in designing, constructing and operating large midstream energy projects.

Our Relationship with OGE Energy and CenterPoint Energy

OGE Energy and CenterPoint Energy are aligned with us to grow our distributions. Following the completion of this offering, OGE Energy and CenterPoint Energy will retain a significant interest in us through their approximate % and % limited partner interests in us, respectively. OGE Energy and CenterPoint Energy will each own 50% of the management rights of our general partner and will own all of our incentive distribution rights.

OGE Energy (NYSE: OGE) is the parent company of Oklahoma Gas and Electric Company, or OG&E, a regulated electric utility serving approximately 805,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas. OG&E furnishes retail electric service in 268 communities and their contiguous rural and suburban areas. OG&E's service area includes Oklahoma City, Oklahoma and Fort Smith, Arkansas, the second largest city in that state. Of the 268 communities that OG&E serves, 242 are located in Oklahoma and 26 are located in Arkansas. As of September 30, 2013, OGE Energy had total assets of $9.1 billion and a market capitalization of $7.2 billion.

CenterPoint Energy (NYSE: CNP) is a public utility holding company whose indirect wholly owned subsidiaries include (i) CenterPoint Energy Houston Electric, LLC, which provides electric transmission and distribution services to retail electric providers serving over two million metered customers in a 5,000-square-mile area of the Texas Gulf Coast that has a population of approximately six million people and includes the city of Houston; and (ii) CenterPoint Energy Resources Corp., which owns and operates natural gas distribution systems serving more than three million customers in six states, including customers in the metropolitan areas of Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. As of September 30, 2013, CenterPoint Energy had total assets of $21.6 billion and a market capitalization of $10.3 billion.

Our sponsors are also significant customers of our transportation and storage business segment and continue to own and operate a substantial portfolio of energy assets. For both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 4% of our total gross margin was derived from contracts servicing electric power generation with OGE Energy. For both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 7% of our total gross margin was derived from contracts servicing LDCs owned by CenterPoint Energy.

Our sponsors entered into a number of agreements in connection with our formation. Please read "Certain Relationships and Related Party Transactions" for a detailed description of these agreements, as well as other agreements affecting us and our sponsors. Although we believe our relationships with OGE Energy and CenterPoint Energy are positive attributes, there can be no assurance that we will benefit from these relationships.

RISK FACTORS

An investment in our common units involves risks associated with our business, our regulatory and legal matters, our limited partnership structure and the tax characteristics of our common units. You should carefully consider the risks described in "Risk Factors" beginning on page 25 of this prospectus and the other information in this prospectus before deciding whether to invest in our common units.

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 and its affiliates, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.
- The assumptions underlying the forecast of distributable cash flow that we include under the caption "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.
- Our contracts are subject to renewal risks.
- We depend on a small number of customers for a significant portion of our firm transportation and storage services revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of our transportation and storage services and our consolidated financial position, results of operations and our ability to make cash distributions to our unitholders.
- Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Risks Related to an Investment in Us

- Our general partner and its affiliates, including OGE Energy and CenterPoint Energy, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.
- If you are not an Eligible Holder, your common units may be subject to redemption.
- Our partnership agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties.
- Our partnership agreement restricts the remedies available to holders of our common units for 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 will not initially be able to remove our general partner without its consent.
- You will experience immediate and substantial dilution in pro forma net tangible book value of $ per common unit.
- 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.

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our distributable cash flow 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 distributable cash flow 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 of applicable law, possibly on a retroactive basis.
- Our unitholders' share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

FORMATION TRANSACTIONS AND PARTNERSHIP STRUCTURE

We were formed in May 2013 by affiliates of CenterPoint Energy, OGE Energy and ArcLight to own, operate and develop a diversified portfolio of complementary midstream businesses previously operated by OGE Energy and CenterPoint Energy. Pursuant to a master formation agreement among our sponsors and ArcLight, the following transactions, which we refer to as our formation transactions, occurred in connection with our formation:

- CenterPoint Energy converted CenterPoint Energy Field Services, LLC, an indirect wholly owned subsidiary, or CEFS, into a Delaware limited partnership, which subsequently changed its name to Enable Midstream Partners, LP;
- CenterPoint Energy contributed certain equity interests in its subsidiaries that conduct the remaining portion of its midstream business to Enable Midstream Partners, LP; and
- OGE Energy and ArcLight contributed 100% of the equity interests in Enogex LLC, a Delaware limited liability company (Enogex), to Enable Midstream Partners, LP.

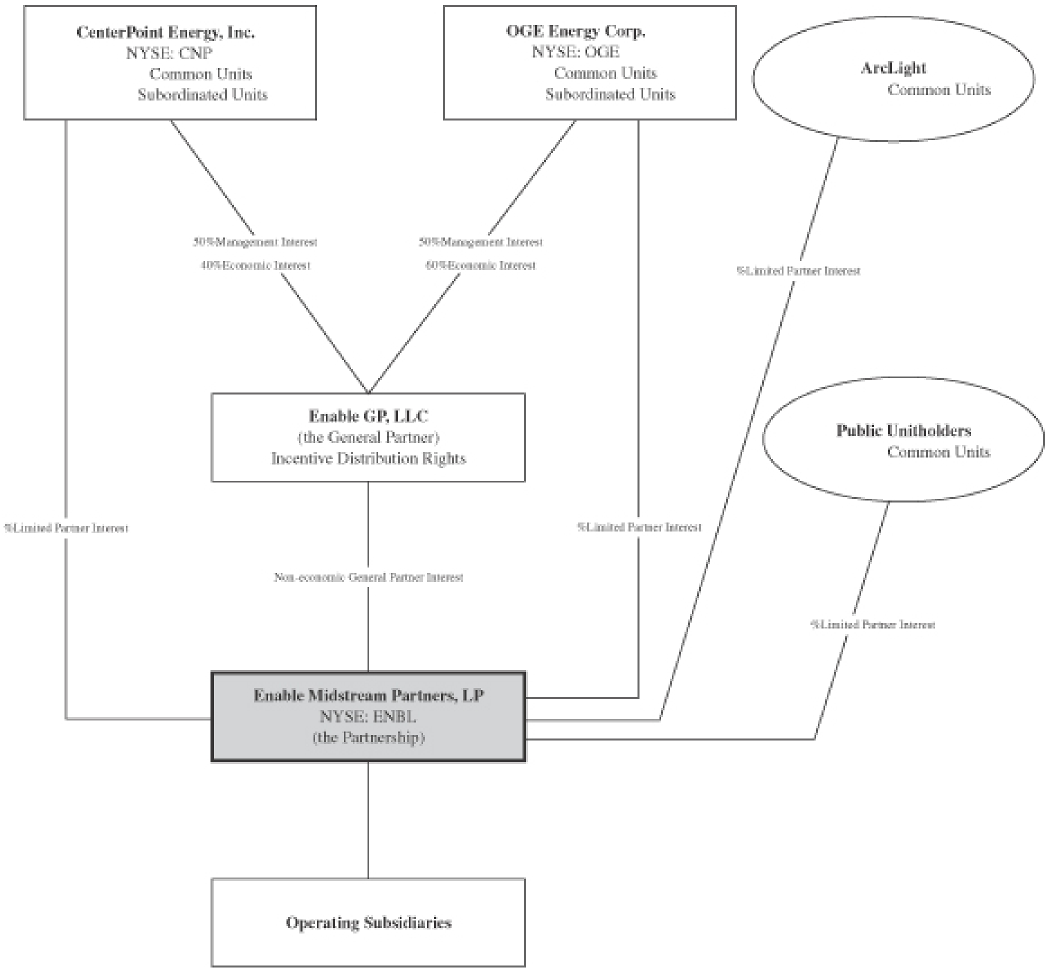
As consideration for the contribution of these assets and agreements, we issued 291,002,583 common units to CenterPoint Energy, 141,956,176 common units to OGE Energy and 65,908,224 common units to ArcLight. We also issued a non-economic general partner interest to Enable GP. Enable GP is equally controlled by CenterPoint Energy and OGE Energy, with each owning 50% of the management rights. Enable GP holds all of our incentive distribution rights, 40% of which are allocated to CenterPoint Energy and 60% of which are allocated to OGE Energy. In connection with this offering,   of CenterPoint Energy's common units and   of OGE Energy's common units will be converted into subordinated units.

We also entered into a number of agreements with our sponsors in connection with our formation. These agreements included an agreement with respect to the transfer of CenterPoint Energy's remaining 25.05% interest in SESH to us, an omnibus agreement, certain services and employment agreements and tax sharing agreements. In addition, upon our formation, we entered into our $1.05 billion three-year term loan facility and our $1.4 billion five-year revolving credit facility.

ORGANIZATIONAL STRUCTURE

The diagram below depicts a simplified organization and ownership chart after giving effect to the offering. After giving effect to this offering, our units will be held as follows:

Public Common Units	%
Common Units Held by:	
CenterPoint Energy	%
OGE Energy	%
ArcLight	%
Subordinated Units Held by:	
CenterPoint Energy	%
OGE Energy	%
General Partner Interest	0.0%
Total	100.0%



MANAGEMENT OF ENABLE MIDSTREAM PARTNERS, LP

Enable GP, LLC, our general partner, will manage our business and operations. The board of directors and executive officers of our general partner will oversee our operations and make decisions on our behalf. Certain executive officers and directors of OGE Energy and CenterPoint also serve as executive officers or directors of our general partner.

Unlike shareholders in a publicly traded corporation, our common unitholders will not be entitled to elect our general partner or its directors. OGE Energy and CenterPoint Energy each have the right to designate two members of the board of directors of our general partner, with any additional members of our board of directors being designated collectively by OGE Energy and CenterPoint Energy. At the closing of this offering, our general partner will have two directors who are independent as defined under the independence standards established by the New York Stock Exchange, or NYSE. For information about the executive officers and directors of our general partner, please read "Management."

SUMMARY OF CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Our general partner has a duty to manage our partnership in a manner it subjectively believes is in our best interests. However, the officers and directors of our general partner also have duties to manage our general partner in a manner beneficial to its owners, OGE Energy and CenterPoint Energy. Additionally, except for our President and Chief Executive Officer, who will be employed by one of our subsidiaries, all of our executive officers and initial directors are officers and/or directors of OGE Energy or CenterPoint Energy. As a result, conflicts of interest may arise in the future between us and our common unitholders, on the one hand, and OGE Energy and CenterPoint Energy and our general partner, on the other hand. For a more detailed description of the conflicts of interest of our general partner, please read "Risk Factors—Risks Related to an Investment in Us" and "Conflicts of Interest and Fiduciary Duties—Conflicts of Interest."

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. Our partnership agreement also provides that, subject to the provisions contained in the omnibus agreement, affiliates of our general partner, including OGE Energy and CenterPoint Energy and their other subsidiaries and affiliates, are permitted to compete with us. We may enter into additional agreements in the future with OGE Energy and CenterPoint Energy relating to the purchase of additional assets, the provision of certain services to us by OGE Energy or CenterPoint Energy and other matters. In the performance of their obligations under these agreements, OGE Energy and CenterPoint Energy and their subsidiaries are not held to a fiduciary duty standard of care to us, our general partner or our limited partners, but rather to the standard of care specified in these agreements. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and each common unitholder is treated as having consented 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.

For a description of our other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions."

PRINCIPAL EXECUTIVE OFFICES AND INTERNET ADDRESS

Our principal executive offices are located at One Leadership Square, 211 North Robinson Avenue, Suite 950, Oklahoma City, Oklahoma 73102, and our telephone number is (405) 525-7788. Our website is located at *www.   .com*. We expect to make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or the SEC, available, free of charge, on 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.

THE OFFERING

Common units offered to the public	common units or 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, representing % and %, respectively, limited partner interests in us (common units and subordinated units, representing % and %, respectively, limited partner interests in us if the underwriters exercise in full their option to purchase additional common units). In addition, our general partner will own a non-economic general partner interest in us.
Use of proceeds	We expect to receive net proceeds from this offering of approximately $ million, after deducting underwriting discounts and commissions and offering expenses. We base this amount on an assumed initial public offering price of $ per common unit. We intend to use approximately $ of the net proceeds of this offering for general partnership purposes, including the funding of expansion capital expenditures, approximately $ to pay down debt under our revolving credit facility and approximately $16 million to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts. Affiliates of each of the underwriters are lenders under our revolving credit facility and will, in that respect, receive a portion of the proceeds from this offering through the repayment of borrowings outstanding under our revolving credit facility. Please read “Underwriting.” If the underwriters’ option to purchase additional common units is exercised in full, the additional net proceeds will be approximately $ million. We intend to apply the additional net proceeds for general partnership purposes.
Cash distributions	We intend to pay the minimum quarterly distribution of $ per unit ($ per unit on an annualized basis) to the extent we have sufficient cash from operations after 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,” and we define its meaning in our partnership agreement. Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors described in more detail under the caption “Cash Distribution Policy and Restrictions on Distributions.”

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We will adjust the amount of our distribution for the period from the completion of this offering through , based on the actual length of that period.

Our partnership agreement requires us to distribute all of our available cash each quarter in the following manner:

- *first*, to the holders of common units, until each common unit has received the minimum quarterly distribution of $ plus any arrearages from prior quarters;
- *second*, to the holders of subordinated units, until each subordinated unit has received the minimum quarterly distribution of $; and
- *third*, to all unitholders, pro rata, 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 increasing percentages, up to 50.0%, of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions" because they incentivize our general partner to increase distributions to our unitholders. In certain circumstances, our general partner, as the initial holder of our incentive distribution rights, will have the right to reset the minimum quarterly distribution and the target distribution levels at which the incentive distributions receive increasing percentages of the cash we distribute to higher levels based on our cash distributions at the time of the exercise of this reset election. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions."

Prior to making distributions, we will reimburse OGE Energy and CenterPoint Energy for direct or allocated costs and expenses incurred by them on our behalf pursuant to the services agreements and the employee transition agreements. Please read "Certain Relationships and Related Party Transactions—Agreements Governing the Offering Transactions."

Pro forma distributable cash flow generated during the year ended December 31, 2012 and the twelve months ended September 30, 2013 was approximately $612 million and $549 million, respectively. The amount of cash we will need to pay the minimum quarterly distribution for four quarters on our common units and subordinated units to be

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	outstanding immediately after this offering will be approximately $ million (or an average of approximately $ million per quarter). As a result, we would have had sufficient distributable cash flow to pay the full minimum quarterly distribution of $ per unit per quarter ($ per unit on an annualized basis) on all of our common units and subordinated units for both the year ended December 31, 2012 and the twelve-month period ended September 30, 2013. Please read "Cash Distribution Policy and Restrictions on Distributions—Unaudited Pro Forma Distributable Cash Flow for the Year Ended December 31, 2012 and the Twelve Months Ended September 30, 2013." We believe that, based on the financial forecasts and related assumptions included under the caption "Cash Distribution Policy and Restrictions on Distributions—Estimated Distributable Cash Flow for the Twelve Months Ending December 31, 2014," we will have sufficient distributable cash flow to make cash distributions for the twelve months ending December 31, 2014, at the minimum quarterly distribution rate of $ per unit per quarter ($ per unit on an annualized basis) on all common units and subordinated units outstanding immediately after completion of this offering. However, our actual results of operations, cash flows and financial condition during the forecast period may vary from the forecast.
Subordinated units	OGE Energy and CenterPoint Energy will initially indirectly own all of our subordinated units. The principal difference between our common units and 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. If we do not pay distributions on our subordinated units, our subordinated units will not accrue arrearages for those unpaid distributions.
Conversion of subordinated units	The subordination period will end on the first business day after we have earned and paid at least (i) $ (the minimum quarterly distribution on an annualized basis) on each outstanding common and subordinated unit, for each of three consecutive, non-overlapping four-quarter periods ending on or after

	, or (ii) $ (150% of the annualized minimum quarterly distribution) on each outstanding common unit and subordinated unit, in addition to any distribution made in respect of the incentive distribution rights, for any four-consecutive-quarter period ending on or after , in each case provided that there are no arrearages on our common units at that time. In addition, the subordination period will end upon the removal of our general partner other than for cause if the units held by our general partner and its affiliates are not voted in favor of such removal. When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions—Subordination Period."
Issuance of additional units	We can issue an unlimited number of units without the consent of our unitholders. Please see "Units Eligible for Future Sale" and "The Partnership Agreement—Issuance of Additional Partnership Interests."
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 not have the right to elect our general partner or its directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least 75% of our outstanding common and subordinated units, including any common and subordinated units owned by our general partner and its affiliates, voting together as a single class. Upon closing of this offering, OGE Energy and CenterPoint Energy will own an aggregate of approximately % of our common and subordinated units. This will give OGE Energy and CenterPoint Energy 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% of the outstanding common units, our general partner will have the right, but not the obligation, to purchase all, but not less than all, of the remaining common units at a price not less than the then-current market price of the common units, as calculated in accordance with our partnership agreement.

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 , 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 common unit, we estimate that your average allocable taxable income per year will be no more than $ per common unit. Thereafter, the ratio of allocable taxable income to cash distributions to you could substantially increase. Please read "Material Federal Income Tax Consequences—Tax Consequences of Unit Ownership—Ratio of Taxable Income to Distributions."
Material 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, please read "Material Federal Income Tax Consequences."
Exchange listing	We have applied to list the common units on the NYSE under the symbol "ENBL."

SUMMARY HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following tables set forth, for the periods and as of the dates indicated, the summary historical financial and operating data of Enable Midstream Partners, LP, which is derived from the historical books and records of the partnership, the summary historical financial and operating data of Enogex, which is derived from the historical books and records of Enogex, and the pro forma financial and operating data of Enable Midstream Partners, LP. On May 1, 2013 (formation), OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the partnership in exchange for common units and, for OGE Energy only, interests in our general partner. The transaction was considered a business combination for accounting purposes, with the partnership considered the acquirer of Enogex. Subsequent to May 1, 2013, the financial and operating data of the partnership are consolidated to reflect the acquisition of Enogex and the retention of certain assets and liabilities by CenterPoint Energy. The following tables should be read together with, and are qualified in their entirety by reference to, the historical and unaudited pro forma combined and consolidated financial statements, as applicable, and the accompanying notes included elsewhere in this prospectus.

The summary historical financial and operating data of Enable Midstream Partners, LP for the years ended December 31, 2012, 2011 and 2010 and balance sheet data as of December 31, 2012 and 2011 is derived from and should be read in conjunction with the audited historical combined financial statements of the partnership included elsewhere in this prospectus. The operating data for all periods is unaudited. The following table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The summary historical financial and operating data of Enogex for the years ended December 31, 2012, 2011 and 2010 and balance sheet data as of December 31, 2012 and 2011 is derived from and should be read in conjunction with the audited historical consolidated financial statements of Enogex included elsewhere in this prospectus. The operating data for all periods is unaudited.

The summary unaudited pro forma financial and operating data is derived from and should be read in conjunction with the unaudited pro forma combined financial statements of Enable Midstream Partners, LP included elsewhere in this prospectus. The pro forma balance sheet assumes that the offering occurred as of September 30, 2013 and the pro forma condensed combined statements of income for the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012 assume that our formation transactions and this offering, with respect to unit and per unit information, occurred as of January 1, 2012. These transactions include, and the pro forma financial data gives effect to, the following:

- The acquisition of Enogex on May 1, 2013, including (1) the incremental depreciation and amortization incurred on the fair value adjustment of Enogex's assets, (2) adjustments to revenue and cost of sales to reflect purchase price adjustments for the recurring impact of certain loss contracts and deferred revenues and (3) a reduction to interest expense for recognition of a premium on Enogex's fixed rate senior notes;
- A reduction in the historical interest income received on the notes receivable—affiliated companies from CenterPoint Energy, which were paid off at formation, and the interest expense incurred on notes payable—affiliated companies to CenterPoint Energy and OGE Energy prior to May 1, 2013, which were repaid at formation;
- The entrance into a $1.05 billion 3-year senior unsecured term loan facility by the partnership and the incremental interest expense and amortization of deferred financing costs related thereto;
- The entrance into a $1.4 billion senior unsecured revolving credit facility by the partnership and the incremental interest expense and amortization of deferred financing costs related thereto;
- A reduction for the elimination of federal and state income taxes, except for Texas state margin taxes;

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- A reduction in the partnership's interest in SESH from 50% to 24.95%;
- The consummation of this offering and our issuance of common units to the public and the conversion of common units of CenterPoint Energy and common units of OGE Energy into subordinated units; and
- The application of the net proceeds of this offering as described in "Use of Proceeds."

The pro forma financial data does not give effect to the estimated $3 million in incremental annual operation and maintenance expense we expect to incur as a result of being a publicly traded partnership. The pro forma financial data does not give effect to any potential cost savings or other operating efficiencies from the integration of the partnership and Enogex. The pro forma financial data does not reflect adjustments for the execution of service agreements with CenterPoint Energy and OGE Energy upon formation since the costs under these service agreements were previously incurred by the partnership and Enogex on a similar basis. The pro forma financial data does not adjust for acquisition related costs since the partnership incurred no acquisition related costs in the Condensed Combined and Consolidated Statement of Income during any period presented based upon the terms in the master formation agreement. For a description of the step acquisition gain, please refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Pro Forma."

The following tables include the financial measures of gross margin, which we use as a measure of performance, Adjusted EBITDA, which we use as a measure of performance and liquidity, and distributable cash flow, which we use as a measure of liquidity. Gross margin, Adjusted EBITDA and distributable cash flow are not calculated and presented in accordance with GAAP. We define gross margin as total revenues minus cost of goods sold, excluding depreciation and amortization. We define Adjusted EBITDA as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results. For a reconciliation of gross margin, Adjusted EBITDA and distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please see "—Non-GAAP Financial Measures."

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	Enable Midstream Partners, LP Historical			Enogex LLC Historical			Enable Midstream Partners, LP Pro Forma		
	Year Ended December 31,			Year Ended December 31,			Year Ended December 31,	Nine Months Ended September 30,	
	2012	2011	2010	2012	2011	2010	2012	2013	2012
	(In millions, except unit, per unit and operating data)								
Results of Operations Data:									
Revenues	$ 952	$ 932	$ 871	$ 1,609	$ 1,787	$ 1,708	$ 2,564	$2,296	$1,866
Cost of goods sold, excluding depreciation and amortization	129	101	98	1,120	1,346	1,285	1,238	1,312	882
Operation and maintenance	267	263	233	179	167	149	446	366	323
Depreciation and amortization	106	91	77	109	78	71	273	205	198
Impairments	—	—	—	—	6	1	—	12	—
Gain on insurance proceeds	—	—	—	(8)	(3)	—	(8)	—	(8)
Taxes other than income	34	37	37	23	18	17	57	45	46
Operating income	416	440	426	186	175	185	558	356	425
Interest expense	(85)	(90)	(83)	(32)	(23)	(31)	(45)	(35)	(33)
Equity in earnings of equity method affiliates	31	31	29	—	—	—	18	9	15
Interest income—affiliated companies	21	14	9	—	—	—	—	—	—
Step acquisition gain	136	—	—	—	—	—	136	—	136
Other, net	—	—	(2)	(4)	3	—	(4)	9	—
Income before income taxes	519	395	379	150	155	154	663	339	543
Income tax expense (benefit)	203	163	155	—	—	(325)	3	1	2
Net income	$ 316	$ 232	$ 224	$ 150	$ 155	$ 479	$ 660	$ 338	$ 541
Less: Net income (loss) attributable to noncontrolling interest	—	—	—	2	(1)	3	2	2	2
Net income attributable to controlling interest	$ 316	$ 232	$ 224	$ 148	$ 156	$ 476	$ 658	$ 336	$ 539
Number of outstanding limited partner units									
Basic and diluted earnings per limited partner unit									
Balance Sheet Data (at period end):									
Property, plant and equipment, net	$ 4,705	$ 4,070	$ 3,876	$ 2,262	$ 1,889	$ 1,553			
Total assets	6,482	5,796	5,463	2,651	2,277	1,757			
Long-term debt, including current portion	1,762	1,568	1,671	698	598	473			
Enable Midstream Partners, LP Partners' Capital	3,215	2,898	2,666						
Enogex LLC Member's Interest				1,417	1,265	925			
Cash Flow Data:									
Net cash flows provided by (used in):									
Operating activities	$ 451	$ 662	$ 308	$ 316	$ 253	$ 318			
Investing activities	(645)	(560)	(800)	(508)	(576)	(227)			
Financing activities	194	(102)	492	189	325	(90)			
Other Financial Data:									
Gross margin	$ 823	$ 831	$ 773	$ 489	$ 441	$ 423	$ 1,326	$ 984	$ 984
Adjusted EBITDA	$ 561	$ 570	$ 543	$ 281	$ 260	$ 254	$ 837	$ 586	$ 628
Distributable cash flow							$ 612	$ 414	$ 477

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	Enable Midstream Partners, LP Historical			Enogex LLC Historical			Enable Midstream Partners, LP Pro Forma		
	Year Ended December 31,			Year Ended December 31,			Year Ended December 31,	Nine Months Ended September 30,	
	2012	2011	2010	2012	2011	2010	2012	2013	2012
	(In millions, except unit, per unit and operating data)								
Operating Data:									
Gathered volumes—TBtu	874	794	647	517	497	482	1,391	985	1,041
Gathered volumes—TBtu/d	2.39	2.17	1.77	1.41	1.36	1.32	3.80	3.61	3.80
Natural gas processed volumes—TBtu	80	47	57	357	290	299	437	397	306
Natural gas processed volumes—TBtu/d	0.22	0.13	0.16	0.98	0.79	0.82	1.20	1.46	1.12
Total NGLs sold—millions of gallons/d	0.25	0.09	0.12	2.38	1.88	1.88	2.64	2.49	2.58
Transported volumes—TBtu	1,378	1,596	1,704	761	701	609	2,139	1,537	1,596
Transportation volumes— TBtu/d	3.76	4.37	4.67	1.60	1.63	1.48	5.36	5.05	5.37
Interstate firm contracted capacity—Bcf/d	7.30	7.33	7.44	—	—	—	7.30	7.17	7.37
Intrastate average deliveries—TBtu/d	—	—	—	1.60	1.63	1.48	1.60	1.59	1.60

NON-GAAP FINANCIAL MEASURES

We define gross margin as total revenues minus cost of goods sold, excluding depreciation and amortization. We define Adjusted EBITDA as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results. The economic substance behind the 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. Gross margin, Adjusted EBITDA and distributable cash flow are supplemental financial measures that management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies may use, to assess:

- our operating performance as compared to those of other publicly traded partnerships in the midstream energy industry, without regard to capital structure or historical cost basis;
- the ability of our assets to generate sufficient cash flow to make distributions to our partners;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the returns on investment of various investment opportunities.

We believe that the presentation of gross margin, Adjusted EBITDA and distributable cash flow provides information useful to investors in assessing our financial condition and results of operations. Gross margin, Adjusted EBITDA and distributable cash flow should not be considered as alternatives to net income, operating income, revenue, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. Gross margin, Adjusted EBITDA and distributable cash flow have important limitations as an analytical tool because they exclude some but not all items that affect the most directly comparable GAAP measures. Additionally, because gross margin, Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of gross margin, Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

The following table presents a reconciliation of (i) gross margin to revenues, (ii) Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest and (iii) Adjusted EBITDA to net cash provided by operating activities, in each case, the most directly comparable GAAP financial measures, on a historical basis and pro forma basis, as applicable, for each of the periods indicated.

	Enable Midstream Partners, LP Historical			Enogex LLC Historical			Enable Midstream Partners, LP Pro Forma		
	Year Ended December 31,			Year Ended December 31,			Year Ended December 31,	Nine Months Ended September 30,	
	2012	2011	2010	2012	2011	2010	2012	2013	2012
						(in millions)			
Reconciliation of Gross Margin to Revenues:									
Revenues	$ 952	$932	$871	$1,609	$1,787	$1,708	$ 2,564	$2,296	$1,866
Cost of goods sold, excluding depreciation and amortization	129	101	98	1,120	1,346	1,285	1,238	1,312	882
Gross margin	$ 823	$831	$773	$ 489	$ 441	$ 423	$ 1,326	$ 984	$ 984
Reconciliation of Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest:									
Net income attributable to Enable Midstream Partners, LP	$ 316	$232	$224	$ 148	$ 156	$ 476	$ 658	$ 336	$ 539
Add:									
Depreciation and amortization expense	106	91	77	109	78	71	273	205	198
Interest expense, net of interest income	64	76	74	32	23	31	45	35	33
Income tax expense (benefit)	203	163	155	—	—	(325)	3	1	2
EBITDA	$ 689	$562	$530	$ 289	$ 257	$ 253	$ 979	$ 577	$ 772
Add:									
Impairment	—	—	—	—	6	1	—	12	—
Distributions from equity method affiliates	39	39	42	—	—	—	20	16	15
Less:									
Equity in earnings of equity method affiliates	(31)	(31)	(29)	—	—	—	(18)	(9)	(15)
Gain on insurance proceeds	—	—	—	(8)	(3)	—	(8)	—	(8)
Gain on disposition	—	—	—	—	—	—	—	(10)	—
Step acquisition gain	(136)	—	—	—	—	—	(136)	—	(136)
Adjusted EBITDA	$ 561	$570	$543	$ 281	$ 260	$ 254	$ 837	$ 586	$ 628
Less:									
Adjusted interest expense, net							(55)	(43)	(41)
Expansion capital expenditures							(912)	(405)	(741)
Maintenance capital expenditures							(167)	(127)	(108)
Incremental operation and maintenance expense of being a public entity							(3)	(2)	(2)
Demand fees associated with legacy marketing business loss contracts							(10)	(8)	(8)
Add:									
Borrowings to fund demand fees associated with legacy marketing business loss contracts							10	8	8
Borrowings for expansion capital expenditures							912	405	741
Distributable cash flow							$ 612	$ 414	$ 477

	Enable Midstream Partners, LP Historical			Enogex LLC Historical			Enable Midstream Partners, LP Pro Forma		
	Year Ended December 31,			Year Ended December 31,			Year Ended December 31,	Nine Months Ended September 30,	
	2012	2011	2010	2012	2011	2010	2012	2013	2012
						(in millions)			
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:									
Net cash provided by operating activities	$ 451	$ 662	$ 308	$316	$253	$ 318			
Interest expense, net of interest income	64	76	74	32	23	31			
Net (income) loss attributable to noncontrolling interest	—	—	—	(2)	1	(3)			
Income tax expense (benefit)	203	163	155	—	—	(325)			
Deferred income tax (expense) benefit	(196)	(176)	(184)	—	—	353			
Equity in earnings of equity method affiliates (net of distributions)	(8)	(8)	(13)	—	—	—			
Impairment	—	—	—	—	(6)	(1)			
Step acquisition gain	136	—	—	—	—	—			
Gain on insurance proceeds				8	3				
Other non-cash items	—	—	—	(6)	(2)	—			
Changes in operating working capital which (provided) used cash:									
Accounts receivable	8	(73)	87	(6)	5	(12)			
Accounts payable	6	(6)	(12)	(40)	(3)	(5)			
Other, including changes in noncurrent assets and liabilities	25	(76)	115	(13)	(17)	(103)			
EBITDA	$ 689	$ 562	$ 530	$289	$257	$ 253			
Add:									
Impairment	—	—	—	—	6	1			
Distributions from equity method affiliates	39	39	42	—	—	—			
Less:									
Equity in earnings of equity method affiliates	(31)	(31)	(29)	—	—	—			
Gain on insurance proceeds	—	—	—	(8)	(3)	—			
Step acquisition gain	(136)	—	—	—	—	—			
Adjusted EBITDA	$ 561	$ 570	$ 543	$281	$260	$ 254			

RISK FACTORS

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. You should consider carefully 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 actually to occur, 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 and its affiliates, to enable us to pay the minimum quarterly distribution to holders of our common and subordinated units.

In order to pay the minimum quarterly distribution of $ per unit, 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 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 fees and gross margins we realize with respect to the volume of natural gas and crude oil that we handle;
- the prices of, levels of production of, and demand for natural gas and crude oil;
- the volume of natural gas and crude oil we gather, compress, treat, dehydrate, process, fractionate, transport and store;
- the relationship among prices for natural gas, NGLs and crude oil;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other midstream energy companies;
- adverse effects of governmental and environmental regulation;
- the level of our operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

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

- the level and timing of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in 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 see “Cash Distribution Policy and Restrictions on Distributions.”

The assumptions underlying the forecast of distributable cash flow that we include under the caption “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 distributable cash flow set forth in “Cash Distribution Policy and Restrictions on Distributions” includes our forecasted results of operations, Adjusted EBITDA and distributable cash flow for the twelve months ending December 31, 2014. Our ability to pay the full minimum quarterly distribution in the forecast period is based on a number of assumptions that may not prove to be correct and that are discussed in “Cash Distribution Policy and Restrictions on Distributions.” Our financial forecast has been prepared by management, and we have neither received nor requested 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 those discussed in this prospectus, which could cause our Adjusted EBITDA to be materially less than the amount forecasted. If we do not generate the forecasted Adjusted EBITDA, we may not be able to make the minimum quarterly distribution or pay any amount on our common units or subordinated units, and the market price of our common units may decline materially.

Our contracts are subject to renewal risks.

We generate a substantial portion of our gross margins under long-term, fee-based agreements. For the nine months ended September 30, 2013, on a pro forma basis, approximately 75% of our gross margin was generated from contracts that are fee-based and approximately 50% of our gross margin was attributable to firm contracts or contracts with minimum volume commitment features. As these and other 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-margin contracts may desire to enter into contracts under different fee arrangements. To the extent we are unable to renew our existing contracts on terms that are favorable to us, if at all, or successfully manage our overall contract mix over time, our revenue, results of operations and distributable cash flow could be adversely affected.

We depend on a small number of customers for a significant portion of our firm transportation and storage services revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of our transportation and storage services and our consolidated financial position, results of operations and our ability to make cash distributions to our unitholders.

We provide firm transportation and storage services to certain key customers on our system. Our major transportation customers are affiliates of CenterPoint Energy, Laclede, Exxon, OGE Energy and AEP. Our interstate transportation and storage assets were designed and built to serve affiliates of CenterPoint Energy, Laclede, OGE Energy and AEP.

Enable-Mississippi River Transmission, LLC’s (MRT) firm transportation and storage contracts with Laclede are scheduled to expire in 2015 and 2016. The primary terms of Enable Gas Transmission, LLC’s (EGT) firm transportation and storage contracts with CenterPoint Energy’s natural gas distribution business will expire in 2018.

Our firm transportation contract with an affiliate of AEP expires January 1, 2015 and will remain in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. The stated term of the OG&E transportation and storage contract expired April 30, 2009, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 90 days prior to the commencement of the succeeding annual period.

The loss of all or even a portion of the interstate or intrastate transportation and storage services for any of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect our combined and consolidated financial position, results of operations and our ability to make cash distributions to unitholders.

Our businesses are dependent, in part, on the drilling and production decisions of others.

Our businesses are dependent on the continued availability of natural gas and crude oil production. 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, our cash flows associated with wells currently connected to our systems will decline over time. To maintain or increase throughput levels on our gathering and transportation systems and the asset utilization rates at our natural gas processing plants, our customers must continually obtain new natural gas and crude oil supplies. The primary factors affecting our ability to obtain new supplies of natural gas and crude oil and attract new customers to our assets are the level of successful drilling activity near these systems, our ability to compete for volumes from successful new wells and our ability to expand capacity as needed. If we are not able to obtain new supplies of natural gas and crude oil to replace the natural decline in volumes from existing wells, throughput on our gathering, processing, transportation and storage facilities would decline, which could have a material adverse effect on our results of operations and distributable cash flow. We have no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of natural gas, NGLs and crude oil;
- demand for natural gas, NGLs and crude oil;
- 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 new natural gas and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Because of these factors, even if new natural gas or crude oil reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Declines in natural gas or crude oil prices can have a negative impact on exploration, development and production activity and, if sustained, could lead to decreases in such activity. A sustained decline could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in our areas of operation could lead to further reductions in the utilization of our systems, which could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

In addition, it may be more difficult to maintain or increase the current volumes on our gathering systems, as several of the formations in the unconventional resource plays in which we operate generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should we determine that the economics of our gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, we may reduce such capital expenditures, which could cause revenues associated with these assets will decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures relative to throughput over time, which will reduce our distributable cash flow.

Because of these and other factors, even if new reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Reductions in drilling activity would result in our inability to maintain the current levels of throughput on our systems and could have a material adverse effect on our results of operations and distributable cash flow.

Our industry is highly competitive, and increased competitive pressure could adversely affect our results of operations and distributable cash flow.

We compete with similar enterprises in our respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Our competitors include large crude oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil than us. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services we provide to our customers. Excess pipeline capacity in the regions served by our interstate pipelines could also increase competition and adversely impact our ability to renew or enter into new contracts with respect to our available capacity when existing contracts expire. In addition, our customers that are significant producers of natural gas may develop their own gathering, processing, transportation and storage systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and customers. Further, natural gas utilized as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas gathering, processing, transportation and transportation services. All of these competitive pressures could adversely affect our results of operations and distributable cash flow.

We derive a substantial portion of our operating income and cash flow from subsidiaries through which we hold a substantial portion of our assets.

We derive a substantial portion of our operating income and cash flow from, and hold a substantial portion of our assets through, our subsidiaries. As a result, we depend on distributions from our subsidiaries in order to meet our payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide us with funds for our payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit our subsidiaries’ ability to make payments or other distributions to us, and our subsidiaries could agree to contractual restrictions on their ability to make distributions.

Our right to receive any assets of any subsidiary, and therefore the right of our creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary’s creditors, including trade creditors. In addition, even if we were a creditor of any subsidiary, our rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by us.

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 flows 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.

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than we anticipate.

Our business plan calls for extensive investment in capital improvements and additions. We expect that our expansion capital expenditures will be $448 million for the twelve months ending December 31, 2014. For example, we are currently constructing a cryogenic processing plant in Custer County, Oklahoma (the McClure Plant), which will provide an additional 200 MMcf/d of natural gas processing capacity and is expected to be completed in the first quarter of 2014. Another new cryogenic processing plant, which will be located in Grady County, Oklahoma (the Bradley Plant), will provide an additional 200 MMcf/d of processing capacity and is expected to be completed in the first quarter of 2015. In addition, we expect to place additional assets in service in 2014 related to our crude oil gathering pipeline system in North Dakota's Bakken shale formation.

The construction of additions or modifications to our existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond our control and may require the expenditure of significant amounts of capital, which may exceed our estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to labor costs, costs of equipment and materials such as steel, labor shortages or weather or other delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner, if at all, or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. Moreover, our revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand an existing pipeline or construct a new pipeline, the construction may occur over an extended period of time, and we may not receive any material increases in revenues or cash flows until the project is completed. In addition, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, the new facilities may not be able to achieve our expected investment return, which could adversely affect our results of operations and our ability to make cash distributions to unitholders.

In connection with our capital investments, we may engage a third party to estimate potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent we rely on estimates of future production in deciding to construct additions to our systems, those estimates may prove to be inaccurate due to numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect our results of operations and our ability to make cash distributions to unitholders. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and we may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Our results of operations and our ability to make cash distributions to unitholders could be negatively affected by adverse movements in the prices of natural gas, NGLs and crude oil depending on factors that are beyond our control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, LNG, NGLs and crude oil, actions taken by foreign natural gas and oil producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation.

Our keep-whole natural gas processing arrangements, which accounted for 16% of our pro forma natural gas processed volumes in 2012, expose us to fluctuations in the pricing spreads between NGL prices and natural gas prices. Under these arrangements, the processor processes raw natural gas to extract NGLs and pays to the producer the natural gas equivalent Btu value of raw natural gas received from the producer in the form of either processed natural gas or its cash equivalent. The processor is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, the processor’s margin is a function of the difference between the value of the NGLs produced and the cost of the processed natural gas used to replace the natural gas equivalent Btu value of those NGLs. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu of natural gas at higher prices and processing margins are negatively affected.

Our percent-of-proceeds and percent-of-liquids natural gas processing agreements accounted for 48% of our natural gas processed volumes on a pro forma basis in 2012. Under these arrangements, the processor generally gathers raw natural gas from producers at the wellhead, transports the natural gas through its gathering system, processes the natural gas and sells the processed natural gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the actual proceeds of the sale of processed natural gas, NGLs or both, or the expected proceeds based on an index price. We refer to contracts in which the processor shares in specified percentages of the proceeds from the sale of natural gas and NGLs as “percent-of-proceeds” arrangements, and contracts in which the processor receives proceeds from the sale of a percentage of the NGLs or the NGLs themselves as compensation for processing services as “percent-of-liquids” arrangements. These arrangements expose us to risks associated with the price of natural gas and NGLs.

At any given time, our overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that we are a net buyer of natural gas) and a net long position in NGLs (meaning that we are a net seller of NGLs). As a result, our gross margin could be adversely impacted to the extent the price of NGLs decreases in relation to the price of natural gas.

We have limited experience in the crude oil gathering business.

In November 2013, we commenced initial operations on a new crude oil gathering pipeline system in North Dakota’s Bakken shale formation, and we expect to place additional related assets in service in 2014. The gathering system, located in Dunn and McKenzie Counties in North Dakota, has a planned capacity of up to 19,500 barrels per day. These facilities are the first crude oil gathering system that we have built and operated. Other operators of gathering systems in the Bakken shale formation may have more experience in the construction, operation and maintenance of crude oil gathering systems than we do. This relative lack of experience may hinder our ability to fully implement our business plan in a timely and cost efficient manner, which, in turn, may adversely affect our results of operations and our ability to make cash distributions to unitholders.

We provide certain transportation and storage services under long-term, fixed-price "negotiated rate" contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts.

We have been authorized by the Federal Energy Regulatory Commission, or the FERC, to provide transportation and storage services at our facilities at negotiated rates. Generally, negotiated rates are in excess of the maximum recourse rates allowed by the FERC, but it is possible that costs to perform services under "negotiated rate" contracts will exceed the revenues obtained under these agreements. If this occurs, it could decrease the cash flow realized by our systems and, therefore, decrease the cash we have available for distribution to our unitholders.

As of September 30, 2013, approximately 58% of our contracted transportation firm capacity and 43% of our contracted storage firm capacity was subscribed under such "negotiated rate" contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by the FERC. Successful recovery of any shortfall of revenue, representing the difference between "recourse rates" (if higher) and negotiated rates, is not assured under current FERC policies.

If third-party pipelines and other facilities interconnected to our gathering, processing or transportation facilities become partially or fully unavailable, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

We depend upon third-party natural gas pipelines to deliver natural gas to, and take natural gas from, our transportation systems. We also depend on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of the processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of our processing plants, and a prolonged outage or disruption could ultimately result in a reduction in the volume of NGLs we are able to produce. Additionally, we depend on third parties to provide electricity for compression at many of our facilities. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines or other facilities become partially or fully unavailable, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We may obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. A loss of these rights, through our inability to renew right-of-way contracts or otherwise, could cause us to cease operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect our results of operations and our ability to make cash distributions to unitholders.

We conduct a portion of our operations through joint ventures, which subject us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations.

We conduct a portion of our operations through joint ventures with third parties, including affiliates of Spectra Energy Corp, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering LLC. We may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

Our joint venture arrangements may involve risks not otherwise present when operating assets directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture’s obligations, leaving us liable for their shares of joint venture liabilities;
- we may be unable to control the amount of cash we will receive from the joint venture;
- we may incur liabilities as a result of an action taken by our joint venture partners;
- we may be required to devote significant management time to the requirements of and matters relating to the joint ventures;
- our insurance policies may not fully cover loss or damage incurred by both us and our joint venture partners in certain circumstances;
- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations. The agreements under which we formed certain joint ventures may subject us to various risks, limit the actions we may take with respect to the assets subject to the joint venture and require us to grant rights to our joint venture partners that could limit our ability to benefit fully from future positive developments. Some joint ventures require us to make significant capital expenditures. If we do not timely meet our financial commitments or otherwise do not comply with our joint venture agreements, our rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture may be adversely affected. Certain of our joint venture partners may have substantially greater financial resources than we have and we may not be able to secure the funding necessary to participate in operations our joint venture partners propose, thereby reducing our ability to benefit from the joint venture.

Under certain circumstances, affiliates of Spectra Energy Corp will have the right to purchase an ownership interest in SESH at fair market value.

We own a 24.95% ownership interest in SESH. The remaining 25.05% and 50.0% ownership interests are held by affiliates of CenterPoint Energy and Spectra Energy Corp, respectively. Under the master formation agreement, CenterPoint Energy has certain put rights, and we have certain call rights, exercisable with respect to the interest in SESH retained by CenterPoint Energy, under which CenterPoint Energy would contribute to us its interest in SESH at a price equal to the fair market value of the interest at the time the put right or call right is exercised. Please read “Certain Relationships and Related Party Transactions—Master Formation Agreement—Acquisition of Remaining CenterPoint Energy Interest in SESH.”

Upon completion of this offering, CenterPoint Energy will own a % limited partner interest in us. Pursuant to the terms of the limited liability company agreement of SESH, as amended (the SESH LLC

Agreement), if, at any time, CenterPoint Energy owns less than a 50% economic interest in us, affiliates of Spectra Energy Corp will have the right to purchase our 24.95% interest in SESH at fair market value. Affiliates of Spectra Energy Corp will also have a preferential purchase right with respect to any interest in SESH transferred to us by CenterPoint Energy if, at the time such interest is transferred, we are not an “affiliate” of CenterPoint Energy, as such term is defined in the SESH LLC Agreement. Under the master formation agreement, we are entitled to receive the cash consideration related to any exercise of these rights by Spectra Energy Corp or its affiliates.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. Insufficient insurance coverage and increased insurance costs could adversely impact our results of operations and our ability to make cash distributions to unitholders.

Our operations are subject to all of the risks and hazards inherent in the gathering, processing, transportation and storage of natural gas and crude oil, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas, crude oil and other hydrocarbons or losses of natural gas and crude oil 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.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property, plant 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. Our sponsors currently have general liability and property insurance in place to cover certain of our facilities in amounts that they consider appropriate. Such policies are subject to certain limits and deductibles. We do not have business interruption insurance coverage for all of our operations. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of our facilities may not be sufficient to restore the loss or damage without negative impact on our results of operations and our ability to make cash distributions to unitholders.

The use of derivative contracts by us and our subsidiaries in the normal course of business could result in financial losses that could negatively impact our results of operations and our ability to make cash distributions to unitholders.

We and our subsidiaries periodically use derivative instruments, such as swaps, options, futures and forwards, to manage our commodity and financial market risks. We and our subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts, or should a counterparty fail to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Failure to attract and retain an appropriately qualified workforce could adversely impact our results of operations.

As of September 30, 2013, we did not have any direct employees. All of the individuals providing services to us as of that date were doing so as seconded employees by OGE Energy and CenterPoint Energy or pursuant to services agreements with OGE Energy or CenterPoint Energy. On or prior to December 31, 2014, we will provide offers of employment to those seconded employees that we determine to hire. Employees of OGE Energy and CenterPoint Energy that we determine to hire are under no obligation to accept our offer of employment on the terms we provide, or at all.

Our business is dependent on our ability to recruit, retain and motivate employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skill sets to future needs, competition for skilled labor or the unavailability of contract resources may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Our costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect our ability to manage and operate our business.

If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

Our ability to grow is dependent on our ability to access external financing sources.

We expect that our operating subsidiaries will distribute all of their available cash to us and that we will distribute all of our available cash to our unitholders. As a result, we expect that we and our operating subsidiaries will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent we or our operating subsidiaries are unable to finance growth externally, our and our operating subsidiaries' cash distribution policy will significantly impair our and our operating subsidiaries' ability to grow. In addition, because we and our operating subsidiaries distribute all available cash, our and our operating subsidiaries' growth may not be as fast 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, which in turn may impact the available cash that we have to distribute on each unit. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by us or our operating subsidiaries to finance our growth strategy would result in increased interest expense, which in turn may negatively impact the available cash that our operating subsidiaries have to distribute to us, and that we have to distribute to our unitholders.

If we do not make acquisitions or are unable to make acquisitions on economically acceptable terms, our future growth will be limited.

Our ability to grow depends, in part, on the ability to make acquisitions that result in an increase in our cash generated from operations per common unit. If we are unable to make these accretive acquisitions either because: (i) we are unable to identify attractive acquisition targets or we are unable to negotiate purchase contracts on acceptable terms, (ii) we are unable to obtain acquisition financing on economically acceptable terms, or (iii) we are outbid by competitors, then our future growth and ability to increase distributions will be limited.

Our merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated.

From time to time, we have made, and we intend to continue to make, acquisitions of businesses and assets. Such acquisitions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- acquisitions, or the pursuit of acquisitions, could disrupt our ongoing businesses, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

Our and our operating subsidiaries' debt levels may limit our and their flexibility in obtaining additional financing and in pursuing other business opportunities.

As of September 30, 2013, we had approximately $1.7 billion of long-term debt outstanding and $200 million of short-term debt outstanding, excluding the premiums on senior notes. We have $363 million of long-term notes payable-affiliated companies due to CenterPoint Energy. We have a $1.4 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.3 billion was available as of September 30, 2013. Following this offering, we will continue to have the ability to incur additional debt, subject to limitations in our credit facilities. The levels of our debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms, if at all;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our and our operating subsidiaries' ability to service our and their debt will depend upon, among other things, their 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 and their control. If operating results are not sufficient to service our or our operating subsidiaries' current or future indebtedness, we and they may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Our credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond our control, which could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our credit facilities contain customary covenants that, among other things, limit our ability to:

- permit our subsidiaries to incur or guarantee additional debt;
- incur or permit to exist certain liens on assets;
- dispose of assets;
- merge or consolidate with another company or engage in a change of control;
- enter into transactions with affiliates on non-arm's length terms; and
- change the nature of our business.

Our credit facilities also require us to maintain certain financial ratios. Our ability to meet those financial ratios can be affected by events beyond our control, and we cannot assure you that we will meet those ratios. In addition, our credit facilities contain events of default customary for agreements of this nature.

Our ability to comply with the covenants and restrictions contained in our credit facilities may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit facilities, a significant portion of our indebtedness may become immediately due and payable. In addition, our lenders' commitments to make further loans to us under the revolving credit facility may be suspended or terminated. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Affiliates of our general partner, including OGE Energy and CenterPoint Energy, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Under our omnibus agreement, OGE Energy, CenterPoint Energy and their affiliates have agreed to hold or otherwise conduct all of their respective midstream operations located within the United States through us. This requirement will cease to apply to both OGE Energy and CenterPoint Energy as soon as either OGE Energy or CenterPoint Energy ceases to hold any interest in our general partner or at least 20% of our common units. In addition, if OGE Energy or CenterPoint Energy acquires any assets or equity of any person engaged in midstream operations with a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired midstream operations that have not been offered to us), the acquiring party will be required to offer to us such assets or equity for such value. If we do not purchase such assets, the acquiring party will be free to retain and operate such midstream assets, so long as the value of the assets does not reach certain thresholds.

As a result, under the circumstances described above, OGE Energy and CenterPoint Energy have the ability to construct or acquire assets that directly compete with our assets. 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 OGE Energy and CenterPoint Energy. 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 fiduciary duty or other 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 common unitholders. Please read "Conflicts of Interest and Fiduciary Duties."

If our general partner fails to develop or maintain an effective system of internal controls, then we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common units.

Our general partner has sole responsibility for conducting our business and for managing our operations. Prior to this offering, we have not been required to file reports with the SEC. 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. Effective internal controls are necessary for our general partner, on our behalf, to provide reliable financial reports, prevent fraud and operate us successfully as a public company. If our general partner's efforts to maintain its internal controls are not successful, it is unable to maintain adequate controls over our financial processes and reporting in the future or it is unable to assist us in complying with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, our operating results could be harmed or we may fail to meet our reporting obligations. Ineffective internal controls also could cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

We rely on executive officers of our general partner and employees of OGE Energy and CenterPoint Energy for the success of our and our subsidiaries' businesses.

Initially, all of the executive officers of our general partner will be employees of OGE Energy or CenterPoint Energy. We have entered into services agreements with OGE Energy and CenterPoint Energy pursuant to which OGE Energy and CenterPoint Energy perform administrative services for us such as legal, accounting, treasury, finance, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, facilities, fleet management and media services. Affiliates of OGE Energy and CenterPoint Energy conduct businesses and activities of their own in which we have no economic interest. As a result, there could be material competition for the time and effort of the executive officers and employees of OGE Energy and CenterPoint Energy who provide services to our general partner. If the executive officers of our general partner and the employees of OGE Energy and CenterPoint Energy do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make cash distributions may be impaired.

Cyber-attacks, acts of terrorism or other disruptions could adversely impact our results of operations and our ability to make cash distributions to unitholders.

We are subject to cyber-security risks related to breaches in the systems and technology that we use (i) to manage our operations and other business processes and (ii) to protect sensitive information maintained in the normal course of our businesses. The gathering, processing and transportation of natural gas from our gathering, processing and pipeline facilities are dependent on communications among our facilities and with third-party systems that may be delivering natural gas into or receiving natural gas and other products from our facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology, or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt our ability to deliver natural gas and control these assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt our operations and critical business functions, adversely affect our reputation, and subject us to possible legal claims and liability. We are not fully insured against all cyber-security risks, any of which could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. In addition, our natural gas pipeline systems may be targets of terrorist activities that could disrupt our ability to conduct our business and have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to obtain or renew permits necessary for our operations, which could inhibit our ability to do business.

Performance of our operations require that we obtain and maintain a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay the issuance of a new or existing material permit or other approval, or to revoke or substantially modify an existing permit or other approval, could adversely affect our ability to initiate or continue operations at the affected location or facility and on our financial condition, results of operations and cash flows.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations and our ability to make cash distributions to unitholders.

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, delay or increase our costs of construction, restrict or limit the output of certain facilities and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, NGLs and crude oil, air emissions related to our operations and historical industry operations and waste disposal practices. These activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of wastes or requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operators. 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 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 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. We may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Further, stricter requirements could negatively impact our customers' production and operations, resulting in less demand for our services. Please see "Business—Environmental Matters."

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Many of our customers commonly use hydraulic fracturing techniques in their drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act (SDWA) and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which activities could adversely affect demand for our services to those customers.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The U.S. Environmental Protection Agency, or the EPA, has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources is expected to be available for public comment and peer review by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources, including hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Our operations may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Because our operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our facilities, and could delay future permitting. At the federal level, the U.S. Congress has in the past and may in the future consider legislation to reduce emissions of greenhouse gases. On September 22, 2009, the EPA issued a rule requiring nation-wide reporting of greenhouse gas emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Subsequently, on November 30, 2010, the EPA issued a supplemental rulemaking that expanded the types of industrial sources that are subject to or potentially subject to EPA's mandatory greenhouse gas emissions reporting requirements to include petroleum and natural gas systems. On May 13, 2010, the EPA issued the "tailoring rule," which served to increase the greenhouse gas emissions threshold that triggers the permitting requirements for major new (and major modifications to existing) stationary sources. Under a phased-in approach, for most purposes, new permitting provisions are required for new facilities that emit 100,000 tons per year or more of carbon dioxide equivalent (CO_2e) and existing facilities making changes that would increase greenhouse gas emissions by 75,000 CO_2e. The EPA has also indicated in rulemakings that it may further reduce the current regulatory thresholds for greenhouse gas emissions, making additional sources subject to permitting. On June 26, 2012, in Coalition for Responsible Regulation v. EPA, the U.S. Circuit Court of Appeals for the District of Columbia circuit upheld the bases for the tailoring rule, and ruled that no petitioners had standing to challenge it. On October 15, 2013, the U.S. Supreme Court granted a petition for a writ of certiorari to review the appellate court's decision.

In addition, more than one-third of the states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap-and-trade programs. Although many of the state-level initiatives have, to date, focused on large sources of greenhouse gas emissions, such as electric power plants, it is possible that in the future other sources of greenhouse gas emissions, such as our gas-fired compressors, could become subject to greenhouse gas-related state regulations. Depending on the particular program, we could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for our services.

Increased regulatory-imposed costs may increase the cost of consuming, and thereby reduce demand for, the products that we gather, treat and transport. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this view could negatively affect our ability to access capital markets or cause us to receive less favorable terms and conditions. Consequently, legislation and regulatory initiatives aimed at reducing greenhouse gases could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders.

Our operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could have a material adverse effect on our results of operations and our ability to make cash distributions to unitholders.

The rates charged by several of our pipeline systems, including for interstate gas transportation service provided by our intrastate pipelines, are regulated by the FERC. The FERC and state regulatory agencies also regulate other terms and conditions of the services we may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service we might propose or offer, the profitability of our pipeline businesses could suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which could also limit our profitability. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services or otherwise adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Our natural gas interstate pipelines are regulated by the FERC under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or the NGPA, and the Energy Policy Act of 2005, or EPAct of 2005. Generally, the FERC's authority over interstate natural gas transportation extends to:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities;
- extension or abandonment of services and facilities or expansion of existing facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate sales, purchases or natural gas transportation; and
- various other matters.

The FERC's jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to expansions, lateral and other facilities and abandonment of facilities and services. Prior to commencing construction of significant new interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or an order amending its existing certificate, from the FERC. Certain minor expansions are authorized by blanket certificates that the FERC has issued by rule. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any failure by an agency to issue sufficient authorizations or permits in a timely manner for one or more of these projects may mean that we will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that we did not anticipate. Our inability to obtain sufficient permits and authorizations in a timely manner could materially and negatively impact the additional revenues expected from these projects.

The FERC conducts audits to verify compliance with the FERC's regulations and the terms of its orders, including whether the websites of interstate pipelines accurately provide information on the operations and availability of services. The FERC's regulations require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline's FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that the FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require us to seek modification, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers.

The rates, terms and conditions for transporting natural gas in interstate commerce on certain of our intrastate pipelines and for services offered at certain of our storage facilities are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Rates to provide such interstate transportation service must be "fair and equitable" under the NGPA and are subject to review, refund with interest if found not to be fair and equitable, and approval by the FERC at least once every five years.

Our crude oil gathering pipelines are subject to common carrier regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain tariffs on file with the FERC setting forth the rates we charge for providing transportation services, as well as the rules and regulations governing such services. The ICA requires, among other things, that our rates must be "just and reasonable" and that we provide service in a manner that is nondiscriminatory.

Our operations may also be subject to regulation by state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Our pipeline operations that are not regulated by the FERC may be subject to state and local regulation applicable to intrastate natural and transportation services. The relevant states in which we operate include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois. State and local regulations generally focus on safety, environmental and, in some circumstances, prohibition of undue discrimination among shippers. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect our business. Any such state or local regulation could have an adverse effect on our business and the results of our operations.

Our gathering lines may be subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to access to oil and natural gas gathering pipelines and rate discrimination.

Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for processing, including state regulation of production rates and maximum daily production allowable from gas wells. While our gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the regulatory status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC under the NGA, but FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect intrastate markets. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure you that the FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business. Although the FERC has not made a formal determination with respect to all of our facilities we consider to be gathering facilities, we believe that our natural gas gathering pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and are 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 is subject to change based on future determinations by the FERC, the courts or Congress. 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 and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by the FERC.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, our natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on our operations, but we could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

We may incur significant costs and liabilities resulting from pipeline integrity and other similar programs and related repairs.

The U.S. Department of Transportation, or DOT, has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located in “high consequence areas,” which are those areas where a leak or rupture could do the most harm. The regulations require operators, including us, to, among other things:

- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- identify and characterize applicable threats that could impact a high consequence area;
- improve data collection, integration, and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Although many of our pipelines fall within a class that is currently not subject to these requirements, we may incur significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with our non-exempt pipelines. This work is part of our normal integrity management program and we do not expect to incur any extraordinary costs during 2013 or 2014 to complete the testing required by existing DOT regulations and their state counterparts. We have not estimated the costs for any repair, remediation, preventive or mitigation actions that may be determined to be necessary as a result of the testing program, which could be substantial, or any lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. Also, as addressed in the “Business—Safety and Health Regulation,” the scope of the integrity management program and other related pipeline safety programs could be expanded in the future. We have not estimated the cost of complying with such future requirements.

The adoption of financial reform legislation by the United States Congress could adversely affect our ability to use derivative instruments to hedge risks associated with our business.

At times, we may hedge all or a portion of our commodity risk and our interest rate risk. The United States Congress adopted comprehensive financial reform legislation that changed federal oversight and regulation of the derivatives markets and entities, including businesses like ours, that participate in those markets. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was signed into law by the President on July 21, 2010, and requires the Commodity Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the legislation. In its rulemaking under the Dodd-Frank Act, the CFTC adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The CFTC appealed this ruling, but subsequently withdrew its appeal. On November 5, 2013, the CFTC approved a Notice of Proposed Rulemaking designed to implement new position limits regulation. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain. However, reporting obligations for transactions involving non-financial swap counterparties such as us began on July 1, 2013 with regard to interest rate swaps and August 19, 2013 with regard to other commodity swaps such as natural gas swap products.

Under final rules adopted by the CFTC, we believe our hedging transactions will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as us has a required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. The Dodd-Frank Act may also require us to comply with margin requirements in connection with our hedging activities, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and related regulations could significantly increase the cost of derivatives contracts for our industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties, particularly if we are unable to utilize the commercial end user exception with respect to certain of our hedging transactions. If we reduce our use of hedging as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could adversely affect our results of operations and our ability to make cash distributions to unitholders.

Risks Related to an Investment in Us

Our general partner and its affiliates, including OGE Energy and CenterPoint Energy, have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

Following this offering, affiliates of OGE Energy and CenterPoint Energy will continue to own and control our general partner and will continue to appoint all of the officers and directors of our general partner. All of the initial officers and a majority of the initial directors of our general partner are also officers and/or directors of OGE Energy or CenterPoint Energy. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to OGE Energy and CenterPoint Energy. Conflicts of interest will arise between OGE Energy, CenterPoint Energy 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 OGE Energy and CenterPoint Energy 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 OGE Energy or CenterPoint Energy to pursue a business strategy that favors us. The directors and officers of OGE Energy and CenterPoint Energy have a fiduciary duty to make decisions in the best interests of the stockholders of their respective companies, which may be contrary to our interests. OGE Energy and CenterPoint Energy may choose to shift the focus of their investment and growth to areas not served by our assets.

- Our general partner is allowed to take into account the interests of parties other than us, such as OGE Energy and CenterPoint Energy, in resolving conflicts of interest.
- All of the initial officers and a majority of the initial directors of our general partner are also officers and/or directors of OGE Energy or CenterPoint Energy and will owe fiduciary duties to their respective companies. These officers will also devote significant time to the business of OGE Energy and CenterPoint Energy and will be compensated by OGE Energy and CenterPoint Energy accordingly.
- Our partnership agreement replaces the fiduciary duties that would otherwise be owed to us by our general partner with contractual standards governing its duties, limits our general partner's liabilities and restricts the remedies available to our unitholders for actions that, without such 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.
- Disputes may arise under our commercial agreements with OGE Energy and CenterPoint Energy.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership units and the creation, reduction or increase of cash reserves, each of which can affect the amount of distributable cash flow.
- 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 or investment capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units.
- Our general partner determines which costs incurred by it and its affiliates 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 or general partner units or to our general partner in respect of 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 transfer its incentive distribution rights without unitholder approval.
- 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 Fiduciary Duties."

If you are not an Eligible Holder, your common units may be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common and subordinated units. Eligible Holders are limited partners whose (i) federal income tax status is not reasonably likely to have a material adverse effect on the rates that can be charged by us on assets that are subject to regulation by FERC or an analogous regulatory body and (ii) nationality, citizenship or other related status would not create a substantial risk of cancellation or forfeiture of any property in which we have an interest, in each case as determined by our general partner with the advice of counsel. If you are not an Eligible Holder, in certain circumstances as set forth in our partnership agreement, your units may be redeemed by us at the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner. Please read “The Partnership Agreement—Ineligible Holders; Redemption.”

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 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 or in our credit facilities that limit 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.

The reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce our distributable cash flow. 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 OGE Energy and CenterPoint Energy, for costs and expenses they incur and payments they make on our behalf. Pursuant to services agreements we have entered into with each of OGE Energy and CenterPoint Energy, we will reimburse OGE Energy and CenterPoint Energy for the payment of operating expenses related to our operations and for the provision of various general and administrative services performed for our benefit. Payments for these services may be substantial and will reduce the amount of distributable cash flow. Additionally, we will reimburse OGE Energy and CenterPoint Energy for direct or allocated costs and expenses incurred on our behalf, including administrative costs, such as compensation expense for those persons who provide services necessary to run our business, and insurance expenses. We also expect to incur approximately $3 million of incremental annual operation and maintenance expense as a result of being a publicly traded partnership. Please read “Certain Relationships and Related Party Transactions—Omnibus Agreement.” 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 “Cash Distribution Policy and Restrictions on Distributions.”

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.

We cannot assure you that our credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any future downgrade could increase the cost of short-term borrowings. Any downgrade could also lead to higher borrowing costs and, if below investment grade, could require us or our subsidiaries to post cash collateral under our shipping or hedging arrangements or in order to purchase natural gas or letters of credit. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations and our ability to make cash distributions to unitholders could be adversely affected.

The credit and business risk profiles of our general partner, OGE Energy and CenterPoint Energy could adversely affect our credit ratings and profile.

The credit and business risk profiles of our general partner, OGE Energy and CenterPoint Energy may be factors in credit evaluations of a master limited partnership because our general partner can exercise control over our business activities, including our cash distribution and acquisition strategy and business risk profile. Other factors that may be considered are the financial conditions of our general partner, OGE Energy and CenterPoint Energy, including the degree of their financial leverage and their dependence on cash flows from us to service their indebtedness.

OGE Energy and CenterPoint Energy, which indirectly own our general partner, have indebtedness outstanding and are partially dependent on the cash distributions from their general partner and limited partner interests in us to service such indebtedness and pay dividends on their common stock. Any distributions by us to such entities will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards 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 provision 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 other 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;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights 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 Fiduciary Duties—Duties of the General Partner.”

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for 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, the board of directors of our general partner or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the board of directors of our general partner and any committee thereof (including the conflicts committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in the best interests of our partnership, 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 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 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
- 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 or the conflicts committee 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 third and fourth subbullets above, then it will be presumed that, in making its decision, the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Please read “Conflicts of Interest and Fiduciary Duties.”

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the minimum quarterly distribution and the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or our unitholders. This 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, if it has received incentive distributions at the highest level to which it is entitled (50.0%) for each of the prior four consecutive fiscal quarters and the amount of each such distribution did not exceed the adjusted operating surplus for such quarter, respectively, to reset the initial minimum quarterly distribution and cash target distribution levels at higher levels based on the average cash distribution amount per common unit for the two fiscal quarters prior to the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common 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 amount.

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 be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our 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. This risk could be elevated if our incentive distribution rights have been transferred to a third party. Our general partner has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights shall have the same rights as our general partner with respect to resetting target distributions. 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 new common units to our general partner in connection with resetting the target distribution levels related to our general partner 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."

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 to elect our general partner or its board of directors on an annual or other continuing basis. Because OGE Energy and CenterPoint Energy collectively indirectly own 100% of our general partner, the board of directors of our general partner has been, and, as long as OGE Energy and CenterPoint Energy own 100% of our general partner, will continue to be, chosen by OGE Energy and CenterPoint Energy. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Please see "—Even if holders of our common units are dissatisfied, they will not initially be able to remove our general partner without its consent." 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 will not initially be able to remove our general partner without its consent.

The unitholders initially will be unable to remove our general partner without its consent because affiliates of our general partner will own sufficient units upon completion of this offering to be able to prevent its removal. The vote of the holders of at least 75% of all outstanding 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 aggregate 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 under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. "Cause" does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders' dissatisfaction with our general partner's performance in managing us will most likely result in the termination of the subordination period and 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's interest in us and 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 our unitholders. Although the limited liability company agreement of our general partner restricts the ability of OGE Energy and CenterPoint Energy to transfer their ownership of their respective limited liability company interest in our general partner until May 1, 2016, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective limited liability company interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and executive officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and executive officers.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If our general partner transfers its incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of OGE Energy or CenterPoint Energy selling or contributing additional assets to us, as they would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

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

The assumed initial public offering price of $ per unit (the midpoint of the price range set forth on the cover page of this prospectus) exceeds our pro forma net tangible book value of $ per unit. Based on the assumed initial public offering price of $ per 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 see “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, including limited partner interests that rank senior to the common units, 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 distributable cash flow 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;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- 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.

Affiliates of our general partner may sell common units in the public or private markets, which could have an adverse impact on the trading price of the common units.

After the sale of the common units offered hereby, assuming that the underwriters do not exercise their option to purchase additional common units, subsidiaries of OGE Energy and CenterPoint Energy 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 and some may convert earlier under certain circumstances. In addition, we have agreed to provide OGE Energy, CenterPoint Energy and ArcLight with certain registration rights. 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 not less than their then-current market price, as calculated pursuant to the terms of the 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. Upon the completion of this offering, and assuming no exercise of the underwriters’ option to purchase additional common units, affiliates of our general partner 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), affiliates of our general partner will own approximately % of our aggregate outstanding common units. Affiliates of our general partner may acquire additional common units from us in connection with future transactions or through open-market or negotiated purchases. For additional information about this right, please see “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 may 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 see “The Partnership Agreement—Limited Liability.”

Our partnership agreement will designate the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which would limit our unitholders’ ability to choose the judicial forum for disputes with us or our general partner’s directors, officers or other employees.

Our partnership agreement will provide, that, with certain limited exceptions, the Court of Chancery of the State of Delaware will be the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our partnership agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty (including a fiduciary duty) owed by any of our, or our general partner’s, directors, officers, or other employees, or owed by our general partner, to us or our partners, (4) asserting a claim against us arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in our common units is deemed to have received notice of and consented to the foregoing provisions. Although we believe this choice of forum provision benefits us by providing increased consistency in the application of Delaware law in the types of lawsuits to which it applies, the provision may have the effect of discouraging lawsuits against us and our general partner’s directors and officers. The enforceability of similar choice of forum provisions in other companies’ certificates of incorporation or similar governing documents has been challenged in legal proceedings and it is possible that in connection with any action a court could find the choice of forum provisions contained in our partnership agreement to be inapplicable or unenforceable in such action. If a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition and results of operations and our ability to make cash distributions to our unitholders.

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

We have applied to list our common units on the NYSE. Because we will be a publicly traded limited partnership, the NYSE does not require us to have, and we do not intend 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. 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."

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, which we refer to herein as the Delaware 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 the 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. Transferees of common units are liable for both the obligations of the transferor to make contributions to the partnership that are known to the transferee at the time of transfer and for unknown obligations 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.

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 non-recourse to our general partner. Our partnership agreement permits our general partner to limit its liability, 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.

An increase in interest rates could adversely impact the price of our common units, 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 on 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, the market price of our common units is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision purposes. Therefore, changes in interest rates may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on the price of our common units, our ability to issue additional equity to make acquisitions or for other purposes and our ability to make cash distributions at our intended levels.

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. 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:

- the level of our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer or contract;
- 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.”

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, the Sarbanes-Oxley Act of 2002 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 independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal control 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 possibly to result in our general partner having to accept reduced policy limits and coverage. We have included $3 million of estimated annual incremental costs associated with being a publicly traded partnership in our financial forecast included elsewhere in this prospectus, some of which will be allocated to us by OGE Energy and CenterPoint Energy and their affiliates. However, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, you should 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 IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our distributable cash flow 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 Internal Revenue Service, or 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. 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 35.0%, 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 distributable cash flow to our unitholders 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 distributable cash flow 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 such additional tax on us by a state will reduce the distributable cash flow. 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 of applicable law, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, 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. Any modification to the federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. Please read "Material Federal Income Tax Consequences—Partnership Status." We are unable to predict whether any such changes will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. 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 U.S. 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.

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 distributable cash flow 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 distributable cash flow to our unitholders.

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 or other disposition 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" for a further discussion of the foregoing.

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 U.S. 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. A successful IRS challenge 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" for a further discussion of the effect of the depreciation and amortization positions we will adopt.

We prorate our items of income, gain, loss and deduction for U.S. 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 U.S. 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 Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we will adopt. 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. Our counsel has not rendered an opinion with respect to our monthly convention for allocating taxable income and losses. 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 cover 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 cover 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 cover 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 U.S. 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 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. Immediately following this offering, OGE Energy, CenterPoint and ArcLight will in the aggregate indirectly own more than 50% of the total interests in our capital and profits. Therefore, transfers and transfers deemed to occur for tax purposes by OGE Energy, CenterPoint or ArcLight or their affiliates of all or a portion of their respective interests in us could result in a termination of our partnership for federal income tax purposes. 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 if the termination occurs on a day other than December 31 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 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 will likely 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 own 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 will initially own property or conduct business in a number of states, most of which currently impose a personal income tax on individuals, and most of which also impose an income or similar tax on corporations and certain other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose an income tax or similar tax. In certain states, tax losses may not produce a tax benefit in the year incurred and also may not be available to offset income in subsequent tax years. Some states 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 state. Withholding, the amount of which may be greater or less than a particular unitholders' income tax liability to the state, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. It is your responsibility to file all U.S. 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. Please consult your tax advisor.

Compliance with and changes in tax laws could adversely affect our performance.

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

USE OF PROCEEDS

We expect to receive net proceeds from this offering of approximately $ million, after deducting underwriting discounts and commissions and offering expenses. We base this amount on an assumed initial public offering price of $ per common unit. We intend to use:

- approximately $ of the net proceeds of this offering for general partnership purposes, including the funding of expansion capital expenditures;
- approximately $ of the net proceeds of this offering to pay down debt under our revolving credit facility; and
- approximately $16 million of the net proceeds of this offering to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts.

We utilize our revolving credit facility to manage the timing of cash flows and fund short-term working capital deficits. As of November 30, 2013, $325 million was outstanding under our revolving credit facility, with a weighted-average interest rate of 1.79%. Our revolving credit facility matures in May 2018.

If the underwriters' option to purchase additional common units is exercised in full, the additional net proceeds will be approximately $ million. We intend to apply the additional net proceeds for general partnership purposes. If the underwriters exercise in full their option to purchase additional common units, the ownership interest of the public unitholders will increase to common units, representing an aggregate % limited partner interest in us.

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 each of the underwriters are lenders under our revolving credit facility and will, in that respect, receive a portion of the proceeds from this offering through the repayment of borrowings outstanding under our revolving credit facility. Please read "Underwriting."

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 and commissions and offering expenses, 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 1,000,000 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 1,000,000 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 apply the net proceeds for general partnership purposes.

CAPITALIZATION

The following table shows:

- our historical cash and cash equivalents and capitalization as of September 30, 2013; and
- our pro forma cash and cash equivalents and capitalization as of September 30, 2013 after giving effect to this offering and the application of the net proceeds therefrom as described under "Use of Proceeds."

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical and pro forma 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."

	As of September 30, 2013	
	Historical	Pro Forma(1)
	(In millions, except unit amounts)	
Cash and cash equivalents	$ 24	$
Total debt (including current portion and notes payable—affiliated companies)		
Term Loan Facility	$ 1,050	$
Revolving Credit Facility(2)	142	
Long-term notes payable—affiliated companies	363	
Enable Oklahoma Term Loan	250	
Enable Oklahoma 6.875% senior notes due 2014	200	
Enable Oklahoma 6.25% senior notes due 2020	250	
Premium on Enable Oklahoma senior notes	40	
Total debt (including current portion and notes payable—affiliated companies)	$ 2,295	$
Partners' Capital:		
Enable Midstream Partners, LP Partners' Capital	$ 8,152	$
Held by public:		
Common units	—	
Held by OGE Energy:		
Common units	141,956,176	
Subordinated units	—	
Held by CenterPoint Energy:		
Common units	291,002,583	
Subordinated units	—	
Held by ArcLight:		
Common units	65,908,224	
Total Enable Midstream Partners, LP Partners' Capital:	$ 8,152	$
Total capitalization	$ 10,447	$

(1) An increase or decrease in the initial public offering price of $1.00 per common unit would cause the net proceeds from this offering, after deducting underwriting discounts and commissions and offering expenses, to increase or decrease by $ million. If the proceeds increase due to a higher initial public offering price or decrease due to a lower initial public offering price, then the proceeds of this offering used for general partnership purposes will increase or decrease, as applicable, by a corresponding amount.

(2) As of November 30, 2013, total borrowings under our revolving credit facility were $325 million, and $1 million of letters of credit were outstanding.

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. Assuming an initial public offering price of $, on a pro forma basis as of September 30, 2013, our net tangible book value was $ million, or $ per unit. Purchasers of common units in this offering will experience an immediate dilution in net tangible book value per unit for financial accounting purposes, as illustrated in the following table:

Assumed initial public offering price per common unit		$
Pro forma net tangible book value per unit before the offering(1)	$	
Decrease in pro forma 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 pro forma tangible net book value per unit attributable to purchasers in the offering(3)		$

(1) Determined by dividing the number of units (common units and subordinated units) issued to affiliates of CenterPoint Energy, OGE Energy and ArcLight for their contribution of assets and liabilities to us into the net tangible book value of the contributed assets and liabilities.

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

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

The following table sets forth the number of units that we will issue and the total consideration contributed to us by affiliates of OGE Energy, CenterPoint Energy and ArcLight (including our general partner) and by the purchasers of our common units in this offering upon consummation of the transactions contemplated by this prospectus:

	Units Acquired		Total Consideration	
	Number	Percent	Amount	Percent
Affiliates of OGE Energy, CenterPoint Energy and ArcLight(1)(2)(3)				
Purchasers in this offering				
Total		100%		100%

(1) Upon completion of the transactions contemplated by this prospectus, OGE Energy, CenterPoint Energy and ArcLight collectively will own common units and subordinated units. Although OGE Energy and CenterPoint Energy will each also own a 50% management interest in our general partner, our general partner's general partner interest is not entitled to any distributions from available cash, and, accordingly, is not included in these calculations. OGE Energy and CenterPoint Energy are also entitled to 60% and 40%, respectively, of the incentive distribution rights owned by our general partner.

(2) The assets and liabilities of CenterPoint Energy were recorded at historical cost in accordance with GAAP. The assets and liabilities contributed by OGE Energy and ArcLight were recorded at fair value in accordance with GAAP as the formation transactions were considered a business combination for accounting purposes. The net investment of OGE Energy, CenterPoint Energy and ArcLight, as of September 30, 2013, after giving effect to the application of the net proceeds of this offering, is set forth above.

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

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 "—Significant Forecast Assumptions" below. In addition, please read "Cautionary Note Regarding 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 and pro forma operating results, you should refer to our historical and pro forma financial statements and related notes included elsewhere in this prospectus.

General

Rationale for Our Cash Distribution Policy

Our partnership agreement requires that we 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 available cash, because, among other reasons, we believe we will generally finance any expansion capital expenditures from external financing sources. Generally, our available cash is the sum of our (a) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (b) 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 if we were 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 is subject to certain restrictions and may be changed at any time. The reasons for such uncertainties in our stated cash distribution policy include the following factors:

- Our ability to make cash distributions may be limited by certain covenants in our revolving credit facility. Should we be unable to satisfy these covenants, we will be unable to make cash distributions notwithstanding our cash distribution policy. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving Credit Facility."
- Our general partner will have the authority to establish reserves for the proper 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. 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 circumstances where no unitholder approval is required. 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 our general partner and its affiliates) after the subordination period has ended. At the closing of this offering, OGE Energy and CenterPoint Energy will own our general partner as well as approximately   % of our outstanding common units and all of our outstanding

subordinated units, representing an aggregate % limited partner interest in us. Please read "The Partnership Agreement—Amendment of the Partnership Agreement."

- 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 Act, we may not make a distribution to our unitholders 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 due to cash flow shortfalls attributable to a number of operational, commercial or other factors, as well as increases in our operating or operation and maintenance expense, principal and interest payments on our debt, working capital requirements and anticipated cash needs. Our distributable cash flow is directly impacted by our cash expenses necessary to run our business and will be reduced dollar-for-dollar to the extent such uses of cash increase.
- 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 future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations.
- If and to the extent our distributable cash flow materially declines, we may elect to reduce our quarterly cash distributions in order to service or repay our debt or fund expansion capital expenditures.

All available cash distributed by us on any date from any source will be treated as distributed 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. We anticipate that distributions from operating surplus will generally not represent a return of capital. However, operating surplus, as defined in our partnership agreement, includes certain components, including a $ million cash basket, that represent non-operating sources of cash. Accordingly, it is possible that return of capital distributions could be made from operating surplus. Any cash distributed by us in excess of operating surplus will be deemed to be capital surplus under our partnership agreement. 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. We do not anticipate that we will make any distributions from capital surplus.

Our Ability to Grow is Dependent on Our Ability to Access External Financing Sources

Because we will distribute all of our available cash to our unitholders, we expect that we will rely primarily upon external financing sources, including borrowings under our revolving credit facility and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. We do not have any commitment from our general partner or other affiliates, including OGE Energy and CenterPoint Energy, to provide any direct or indirect financial assistance to us following the closing of this offering, except for CenterPoint Energy's guarantee of our term loan facility. 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 and the incremental distributions on the incentive distribution rights may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional borrowings under our revolving credit facility 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.

Our Minimum Quarterly Distribution

Upon the consummation of this offering, our partnership agreement will provide for a minimum quarterly distribution of $ per unit for each complete quarter, or $ per unit on an annualized basis. Our ability to make cash distributions at the minimum quarterly distribution rate will be subject to the factors described above under "—General—Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy." Quarterly distributions, if any, will be made within 45 days after the end of each quarter, on or about the 15th day of each February, May, August and November to holders of record on or about the first day of each such month. If the distribution date does not fall on a business day, we will make the distribution on the first business day immediately following the indicated distribution date. We will not make distributions for the period that begins on , and ends on the day prior to the closing of this offering, other than the required distributions to our sponsors and ArcLight under our partnership agreement. We will adjust the amount of our distribution for the period from the completion of this offering through based on the actual length of the period. The amount of available cash needed to pay the minimum quarterly distribution on all of our common and subordinated units to be outstanding immediately after this offering for one quarter and on an annualized basis is summarized in the table below:

		Minimum Quarterly Distribution	
	Number of Units	One Quarter	Annualized
		(in millions)	
Publicly held common units[1]		$	$
Common units held by OGE Energy		$	$
Subordinated units held by OGE Energy		$	$
Common units held by CenterPoint Energy		$	$
Subordinated units held by CenterPoint Energy		$	$
Common units held by ArcLight		$	$
Total		$	$

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

Our general partner will hold our incentive distribution rights, which entitle the holder to increasing percentages, up to a maximum of 50.0%, of the cash we distribute in excess of $ per unit per quarter.

During the subordination period, before we make any quarterly distributions to our subordinated unitholders, our common unitholders are entitled to receive payment of the full minimum quarterly distribution plus any arrearages in distributions of the minimum quarterly distribution from prior quarters. Please read "Provisions of our Partnership Agreement Relating to Cash Distributions—Subordination Period." We cannot guarantee, however, that we will pay the minimum quarterly distribution on our common units in any quarter.

Although holders of our common units may pursue judicial action to enforce provisions of our partnership agreement, including those related to requirements to make cash distributions as described above, our partnership agreement provides that any determination made by our general partner in its capacity as our general partner must be made in good faith and that any such determination will not be subject to any other standard imposed by the Delaware Act or any other law, rule or regulation or at equity. Our partnership agreement provides that, in order for a determination by our general partner to be made in "good faith," our general partner must subjectively believe that the determination is in our best interests. Please read "Conflicts of Interest and Fiduciary Duties."

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement; however, 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 cash reserves our general partner establishes in accordance with our partnership agreement as described above.

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 December 31, 2014. In those sections, we present two tables, consisting of:

- "Unaudited Pro Forma Distributable Cash Flow for the Year Ended December 31, 2012 and the Twelve Months Ended September 30, 2013," in which we present the amount of cash we would have had available for distribution on a pro forma basis for the year ended December 31, 2012 and the twelve months ended September 30, 2013, derived from our unaudited pro forma financial data that are included elsewhere in this prospectus, as adjusted to give pro forma effect to our formation transactions and this offering; and
- "Estimated Distributable Cash Flow for the Twelve Months Ending December 31, 2014," in which we explain our belief that we will be able to generate sufficient distributable cash flow for us to pay the minimum quarterly distribution on all units for the twelve months ending December 31, 2014.

Unaudited Pro Forma Distributable Cash Flow for the Year Ended December 31, 2012 and the Twelve Months Ended September 30, 2013

If we had completed our formation transactions and this offering on January 1, 2012, our unaudited pro forma distributable cash flow for the year ended December 31, 2012 would have been approximately $612 million. This amount would have been sufficient to pay the full minimum quarterly distribution of $ per unit per quarter ($ per unit on an annualized basis) on all of our common units and subordinated units for such period.

If we had completed our formation transactions and this offering on October 1, 2012, our unaudited pro forma distributable cash flow for the twelve months ended September 30, 2013 would have been approximately $549 million. This amount would have been sufficient to pay the full minimum quarterly distribution of $ per unit per quarter ($ per unit on an annualized basis) on all of our common units and subordinated units for such period.

Our unaudited pro forma available cash for the year ended December 31, 2012 and the twelve months ended September 30, 2013 includes $3 million of estimated incremental operation and maintenance expenses that we expect to incur as a result of becoming a publicly traded partnership. Incremental operation and maintenance 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; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; director and officer liability insurance expenses; and director compensation. These expenses are not reflected in historical financial statements of the partnership or our unaudited pro forma financial statements included elsewhere in the prospectus.

We based the pro forma adjustments upon currently available information and specific estimates and assumptions. The pro forma amounts below do not purport to present our results of operations had our formation transactions and this offering been completed as of the dates indicated. In addition, distributable cash flow is primarily a cash accounting concept, while the historical financial statements of the partnership and our unaudited pro forma financial statements included elsewhere in the prospectus have been prepared on an accrual basis. As a result, you should view the amount of pro forma distributable cash flow only as a general indication of the amount of distributable cash flow that we might have generated had we completed this offering on the dates indicated. The pro forma amounts below are presented on a twelve-month basis, and there is no guarantee that we would have had available cash sufficient to pay the full minimum quarterly distribution on all of our outstanding common units and subordinated units for each quarter within the twelve-month periods presented.

We use the term "distributable cash flow" to measure whether we have generated from our operations, or "earned," a particular amount of cash sufficient to support the payment of the minimum quarterly distributions.

Our partnership agreement contains the concept of “operating surplus” to determine whether our operations are generating sufficient cash to support the distributions that we are paying, as opposed to returning capital to our partners. Please read “Provisions of Our Partnership Agreement Relating to Cash Distributions—Operating Surplus and Capital Surplus—Operating Surplus.” Because operating surplus is a cumulative concept (measured from the initial public offering date, and compared to cumulative distributions from the initial public offering date), we use the term distributable cash flow to approximate operating surplus on an annual, rather than a cumulative, basis. As a result, distributable cash flow is not necessarily indicative of the actual cash we have on hand to distribute or that we are required to distribute.

The following table illustrates, on a pro forma basis, for the year ended December 31, 2012 and the twelve-month period ended September 30, 2013, the amount of cash that would have been available for distribution to our unitholders, assuming that our formation transactions and this offering had been completed on January 1, 2012 and October 1, 2012, respectively. Each of the adjustments reflected or presented below is explained in the footnotes to such adjustments.

Enable Midstream Partners, LP
Unaudited Pro Forma Distributable Cash Flow

	Year Ended December 31, 2012	Twelve Months Ended September 30, 2013
	(In millions)	
Pro Forma Net Income attributable to Enable Midstream Partners, LP	$ 658	$ 455
Add:		
Depreciation and amortization	273	280
Interest expense, net	45	47
Income tax expense	3	2
Pro Forma EBITDA	$ 979	$ 784
Add:		
Impairment[1]	—	12
Estimated distributions from equity method affiliates—SESH	20	21
Less:		
Equity in earnings of equity method affiliates—SESH	(18)	(12)
Gain on insurance proceeds[2]	(8)	—
Gain on disposition[3]	—	(10)
Step acquisition gain[4]	(136)	—
Pro Forma Adjusted EBITDA[5]	$ 837	$ 795
Less:		
Adjusted interest expense, net[6]	(55)	(57)
Expansion capital expenditures[7]	(912)	(576)
Maintenance capital expenditures[8]	(167)	(186)
Incremental operation and maintenance expense of being a public entity[9]	(3)	(3)
Demand fees associated with legacy marketing business loss contracts	(10)	(10)
Add:		
Borrowings to fund demand fees associated with legacy marketing business loss contracts	10	10
Borrowings to fund expansion capital expenditures	912	576
Pro Forma Distributable Cash Flow	$ 612	$ 549
Pro Forma Distributable Cash Flow		
Distribution per unit (based on a minimum quarterly distribution rate of $ per unit)	$	$
Annual distributions to:		
Public common unitholders[10]	$	$
Common units held by OGE Energy		
Common units held by CenterPoint Energy		
Subordinated units held by OGE Energy		
Subordinated units held by CenterPoint Energy		
Total distributions to sponsors		
Total annual minimum cash distributions	$	$
Excess	$	$

(1) Attributable to the assets of the Service Star business line, a component of the gathering and processing business segment that provides measurement and communication services to third parties.
(2) Attributable to the gain recognized by Enogex upon receipt of proceeds from an insurance settlement in excess of recognized losses.
(3) Attributable to the sale by Enogex of certain gas gathering assets in the Texas Panhandle to a customer for cash proceeds of approximately $35 million.
(4) Attributable to the acquisition of the outstanding 50% interest in Waskom in August 2012.
(5) We define Adjusted EBITDA and provide a reconciliation to its most directly comparable financial measures calculated and presented in accordance with GAAP in "Summary—Summary Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures."
(6) Adjusted interest expense, net excludes the effect of the amortization of the premium on Enogex's fixed rate senior notes. This exclusion is the primary reason for the difference between "Interest expense, net" and "Adjusted interest expense, net."
(7) 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.
(8) Maintenance capital expenditures are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets, and 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. Examples of maintenance capital expenditures are expenditures for the repair, refurbishment and replacement of our assets, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations.
(9) Reflects an adjustment for estimated cash expenses 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; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; director and officer liability insurance expenses; and director compensation.
(10) Includes distributions of $ million and $ million to ArcLight for the year ended December 31, 2012 and the twelve months ended September 30, 2013, respectively.

Estimated Distributable Cash Flow for the Twelve Months Ending December 31, 2014

We forecast that our estimated distributable cash flow during the twelve months ending December 31, 2014 will be approximately $508 million. This amount would exceed by $ million the amount needed to pay the minimum quarterly distribution of $ per unit on all of our units for the twelve months ending December 31, 2014.

We are providing the forecast of estimated distributable cash flow to supplement the historical financial statements of the partnership and our unaudited pro forma financial statements included elsewhere in the prospectus in support of our belief that we will have sufficient cash available to allow us to pay cash distributions at the minimum quarterly distribution rate on all of our units for the twelve months ending December 31, 2014. To the extent that there is a shortfall during any quarter in the forecast period, we believe we would be able to make working capital borrowings to pay distributions in such quarter and would likely be able to repay such borrowings in a subsequent quarter, because we believe the total distributable cash flow for the forecast period will be more than sufficient to pay the aggregate minimum quarterly distribution on all of our units. Please read "—Significant Forecast Assumptions" for further information as to the assumptions we have made for the forecast. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" for information as to the accounting policies we have followed for the financial forecast.

Our forecast reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending December 31, 2014. We believe that our actual results of operations will approximate those reflected in our forecast, but we can give no assurance that our forecasted results will be achieved. If our estimates are not achieved, we may not be able to pay the minimum quarterly distribution or any other distribution on our common units. The assumptions and estimates underlying the forecast are inherently uncertain and, though we consider them reasonable as of the date of this prospectus, are subject to a wide variety of significant business, economic and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the forecast, including, among others, risks and uncertainties contained in “Risk Factors.” Accordingly, there can be no assurance that the forecast is indicative of our future performance or that actual results will not differ materially from those presented in the forecast. Inclusion of the forecast in this prospectus should not be regarded as a representation by any person that the results contained in the forecast will be achieved.

Unaudited Prospective Financial Information

We do not as a matter of course make public projections as to future sales, earnings or other results. However, we have prepared the following prospective financial information to present the estimated distributable cash flow to our common unitholders during the forecasted period. 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 our view, 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 expected course of action and our expected future financial performance. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this forecast are cautioned not to place undue reliance on the prospective financial information.

Neither our independent auditors, 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, and assume no responsibility for, and disclaim any association with, the prospective financial information. The independent registered public accounting firm’s report included in this prospectus relates to historical financial information. It does not extend to prospective financial information and should not be read to do so.

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 or the assumptions used to prepare the forecast to reflect events or circumstances after the completion of this offering. In light of this, the statement that we believe that we will have sufficient distributable cash flow to allow us to make the full minimum quarterly distribution on all of our outstanding units for each quarter through December 31, 2014 should not be regarded as a representation by us, the underwriters or any other person that we will make such distribution. Therefore, you are cautioned not to place undue reliance on this information.

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Enable Midstream Partners, LP
Estimated Distributable Cash Flow

	Twelve Months Ending December 31, 2014
	(In millions)
Gross margin[1]	$ 1,364
Operation and maintenance[2]	509
Depreciation and amortization	291
Taxes other than income[3]	65
Operating Income	499
Interest expense, net[4]	(82)
Equity in earnings of equity method affiliates[5]	13
Net income	430
Less: Net income attributable to noncontrolling interest	(2)
Net Income attributable to Enable Midstream Partners, LP	**$ 428**
Add:	
Depreciation and amortization	291
Interest expense, net[4]	82
Estimated EBITDA	**801**
Add:	
Estimated distributions from equity method affiliates – SESH[6]	13
Less:	
Equity in earnings of equity method affiliates – SESH[5]	(13)
Estimated Adjusted EBITDA[7]	**801**
Less:	
Adjusted interest expense, net[8]	(94)
Expansion capital expenditures[9]	(448)
Maintenance capital expenditures[10]	(199)
Demand fees associated with legacy marketing business loss contracts[11]	(10)
Add:	
Offering proceeds retained to fund demand fees associated with legacy marketing business loss contracts	10
Offering proceeds retained to fund expansion capital expenditures	448
Estimated distributable cash flow	**$ 508**
Distribution per unit (based on minimum quarterly distribution rate of $ per unit)	
Annual distributions to public common unitholders[12]	
Annual distributions to sponsors:	
Common units held by OGE Energy	
Common units held by CenterPoint Energy	
Subordinated units held by OGE Energy	
Subordinated units held by CenterPoint Energy	
Total distributions to sponsors	
General partner interest	—
Total distributions at minimum quarterly distribution rate	$
Excess of distributable cash flow over aggregate annualized minimum quarterly distribution	$

(1) We define gross margin and provide a reconciliation to its most directly comparable financial measure calculated in accordance with GAAP in "Summary—Summary Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures."
(2) Includes approximately $3 million of estimated annual incremental operation and maintenance expenses that we expect to incur as a result of being a separate publicly traded partnership, which are not reflected in our unaudited pro forma financial statements.
(3) Taxes other than income are comprised primarily of property taxes and sales and use taxes.
(4) Interest expense, net reflects interest expense forecasted on the borrowings detailed under "—Significant Forecast Assumptions—Financing" on a basis consistent with historical GAAP interest expense, net of interest income. We have assumed the issuance of long-term notes in the first half of 2014 to refinance our existing term loans and a portion of our Enable Oklahoma senior notes.
(5) SESH is a non-consolidated entity in which we own a 24.95% ownership interest. Our earnings from SESH are included on our pro forma consolidated statement of income included elsewhere in this prospectus. Because our earnings from SESH may not necessarily be reflective of the amount of cash we would expect to receive, those earnings are included in our net income but subtracted in connection with our calculation of Adjusted EBITDA. Our estimate of SESH's expected cash contribution to us during the twelve months ending December 31, 2014 is included in our Adjusted EBITDA.
(6) Under the terms of its limited liability company agreement, SESH must distribute 100% of its available cash within 30 days following the end of each quarter to its members. Available cash is generally defined as cash on hand at the end of the applicable quarter, less any reserves determined to be appropriate by the management committee. We expect that we will receive 24.95% of the cash available for distribution from SESH for the twelve months ending December 31, 2014. Because we control only 24.95% of the voting interest of the management committee of SESH, we will not be able to control the determination of available cash with respect to any quarter. Please see "Risk Factors—Risks Related to Our Business—We conduct a portion of our operations through joint ventures, which subject us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations."
(7) We define Adjusted EBITDA and provide a reconciliation to its most directly comparable financial measures calculated and presented in accordance with GAAP in "Summary—Summary Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures."
(8) Adjusted interest expense, net excludes the effect of the amortization of the premium on Enogex's fixed rate senior notes, which is the primary reason for the $12 million difference between Interest expense, net and Adjusted interest expense, net for the twelve months ending December 31, 2014.
(9) 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.
(10) Maintenance capital expenditures are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets, and 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. Examples of maintenance capital expenditures are expenditures for the repair, refurbishment and replacement of our assets to maintain equipment reliability, integrity and safety and to address environmental laws and regulations.
(11) Demand fees associated with legacy marketing business loss contracts are related to three expiring contracts that were entered into by an affiliate of Enogex prior to the formation of the partnership to ship or store gas on third-party assets. These contracts are not core to our operations and we do not expect to realize value above the demand fees. As part of the purchase accounting adjustments at the formation of the partnership, these contracts were marked to their fair value and were recorded on the balance sheet. The remaining expected demand fees associated with these contracts are approximately $10 million, $5 million, and $1 million in the years 2014, 2015 and 2016, respectively. Accordingly, we intend to retain approximately $16 million from the net proceeds of this offering, which we anticipate will fully fund the remaining demand fees associated with these contracts to be paid as they come due.
(12) Includes a distribution of $ million to ArcLight as a holder of common units.

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Significant Forecast Assumptions

The forecast has been prepared by and is the responsibility of management. The forecast reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending December 31, 2014. While the assumptions disclosed in this prospectus are not all-inclusive, the assumptions listed below are those that we believe are material to our forecasted results of operations and any assumptions not discussed below were not deemed to be material. We believe we have a reasonable objective basis for these assumptions. We believe our actual results of operations will approximate those reflected in our forecast, but we can give no assurance that our forecasted results will be achieved. There will likely be differences between our forecast and the actual results and those differences could be material. If the forecast is not achieved, we may not be able to make cash distributions on our common units at the minimum quarterly distribution rate or at all.

Segment Data

The following table compares certain financial data in our gathering and processing and transportation and storage business segments for the twelve months ending December 31, 2014 to the pro forma periods for the year ended December 31, 2012 and the twelve months ended September 30, 2013:

	Pro Forma		Forecasted
	Year Ended December 31, 2012	Twelve Months Ended September 30, 2013	Twelve Months Ending December 31, 2014
	(In millions)		
Gathering and Processing			
Segment Gross Margin	$ 737	$ 765	$ 800
Segment Adjusted EBITDA(1)	467	470	478
Transportation and Storage			
Segment Gross Margin	$ 591	$ 563	$ 564
Segment Adjusted EBITDA(1)	370	325	326

(1) Excludes allocation of $3 million of incremental costs associated with operating as a publicly traded partnership.

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Volume and Commodity Price Assumptions and Sensitivity Analysis

Volumes

The following table compares estimated volumes and certain operational data for our gathering and processing and transportation and storage business segments for the twelve months ending December 31, 2014 to the pro forma periods for the year ended December 31, 2012 and the twelve months ended September 30, 2013:

	Pro Forma		Forecasted
	Year Ended December 31, 2012	Twelve Months Ended September 30, 2013	Twelve Months Ending December 31, 2014
Gathering and Processing			
Natural gas gathering volume (TBtu/d)	3.8	3.7	4.0
Plant natural gas inlet volume (TBtu/d)	1.2	1.5	1.6
Gross NGL production (MBbl/d)(1)	62.9	60.0	72.1
Gross condensate production (MBbl/d)	2.4	2.8	3.0
Crude oil gathered volumes (MBbl/d)	—	—	9.6
Transportation and Storage			
Interstate firm contracted capacity (Bcf/d)(2)(3)	7.3	7.2	7.2
Intrastate average deliveries (TBtu/d)	1.6	1.6	1.6
Average firm storage volumes (Bcf) .	71.5	67.9	69.1

(1) Excludes condensate. Includes third party processing.

(2) Excludes SESH's approximately 1.0 Bcf/d firm contracted capacity.

(3) Actual volumes transported per day may be less than total firm contracted capacity depending on demand.

The actual volume of natural gas that we gather in our gathering and processing business segment will influence whether the amount of distributable cash flow for the twelve months ending December 31, 2014 is above or below our forecast. For example, if the actual volume of natural gas we gather on all of our gathering systems for the twelve months ending December 31, 2014 was 10% higher or lower than our forecasted levels, that change would result in an increase or decrease to distributable cash flow of approximately $60 million, if all other assumptions are held constant.

Commodity Prices

Natural gas, crude oil and NGL prices are factors that influence whether the amount of distributable cash flow for the twelve months ending December 31, 2014 will be above or below our forecast. Approximately $305 million, or 22%, of our total forecasted gross margin for the twelve months ending December 31, 2014 is directly exposed to changes in commodity prices. This compares to approximately 26% of our total gross margin for each of the pro forma periods for the year ended December 31, 2012 and the twelve months ended September 30, 2013. Of the amount included in our forecast period, approximately $288 million is related to the realization of our expected natural gas, NGLs and condensate positions associated with our gathering and processing operations and contractual arrangements. The remaining $17 million is associated with our transportation and storage segment primarily related to sales of natural gas collected from customers under our fixed rate fuel tariff on a portion of our EGT system. We do not have any hedges in place on our expected 2014 commodity positions.

The table below sets forth our estimates for average monthly benchmark commodity prices for the twelve months ending December 31, 2014 compared to actual monthly average prices for the year ended December 31, 2012 and the twelve months ended September 30, 2013. The projected prices that we expect to realize for these commodities reflect various adjustments to the applicable transportation, quality and regional price differentials.

Our forecasted commodity prices are primarily based on market prices for the applicable commodities, as adjusted to take into account third-party market analysis and management's judgment. Based on the natural gas and NGL price assumptions below for the twelve months ending December 31, 2014, we expect to operate our processing assets in ethane rejection mode unless plant capabilities or plant-level economics dictate otherwise.

	Pro Forma		Forecasted
	Year Ended December 31, 2012	Twelve Months Ended September 30, 2013	Twelve Months Ending December 31, 2014
Natural Gas – Henry Hub ($/MMBtu)	$ 2.79	$ 3.67	$ 3.95
Natural Gas Liquids Composite ($/gal)[(1)]			
Mont Belvieu, Texas	$ 0.96	$ 0.83	$ 0.81
Conway, Kansas	$ 0.77	$ 0.79	$ 0.76
Crude Oil - WTI ($/Bbl)	$ 94.92	$ 96.21	$ 94.45

(1) Natural gas liquids composite based on an assumed composition of 45%, 30%, 10%, 5%, and 10% for ethane, propane, normal butane, isobutane and natural gasoline, respectively.

Holding all other assumptions constant, we estimate that (i) a 10.0% increase or decrease in the price of natural gas from forecasted levels would result in an increase or decrease of approximately $20 million in distributable cash flow for the forecast period and (ii) a 10.0% increase or decrease in the price of NGLs from forecasted levels, would result in an increase or decrease of approximately $7 million in distributable cash flow for the forecast period.

Gathering and Processing Gross Margin

We estimate that we will generate gross margin in our gathering and processing segment of $800 million for the twelve months ending December 31, 2014, compared to $737 million for the year ended December 31, 2012 and $765 million for the twelve months ended September 30, 2013, each on a pro forma basis. The increase of $35 million in gross margin for the forecasted period as compared to the pro forma twelve months ended September 30, 2013 is primarily attributable to increased volumes on our Anadarko system in the Greater Granite Wash, SCOOP and Mississippi Lime plays, gathering fees from our Bakken crude oil gathering system that was placed into service in the fourth quarter of 2013 and our operational synergy projects that are expected to add incremental gross margin from field optimization activities. The increase of $28 million in our gathering and processing business segment for the twelve months ended September 30, 2013 compared to the twelve months ended December 31, 2012 was primarily attributable to the acquisition of the remaining 50% interest in Waskom, acquisition of the Amoruso Gathering System and increased volumes on our Anadarko system, partially offset by a decline in NGL prices at Mont Belvieu, a decline in NGL price spreads between Conway and Mont Belvieu and the conversion of a significant processing arrangement from keep-whole to fixed-fee**.**

For the twelve months ending December 31, 2014, we have estimated that approximately $512 million, or 64%, and $288 million, or 36%, of the gross margin in our gathering and processing segment will be fee-based and commodity-based, respectively. In comparison, the corresponding contribution percentages to gross margin by fee-based and commodity-based, respectively, were 56% and 44% for the year ended December 31, 2012 and 59% and 41% for the twelve months ended September 30, 2013, each on a pro forma basis. The expected increase in fee-based gross margin is due to increased gathered volumes resulting in increased gathering and compression fees, increased volumes associated with fixed-fee processing arrangements and a conversion from keep-whole to a fixed-fee contract for a large producer. Approximately $204 million, or 40%, of our total fee-based gathering and processing gross margin for the twelve months ending December 31, 2014 is expected to come from contracts containing minimum volume commitment features. Our commodity-based margin is related to the realization of our natural gas, NGL and condensate positions associated with the operations and contractual terms of our gathering and processing arrangements.

We estimate that the total volumes of natural gas gathered on our systems will average approximately 4 TBtu/d and the total volumes of liquids produced on our systems, including condensate, will average approximately 75 MBbl/d for the twelve months ending December 31, 2014. We estimate that natural gas gathered volumes will increase by approximately 5% and 8% during the twelve months ending December 31, 2014 compared with the pro forma year ended December 31, 2012 and the pro forma twelve months ended September 30, 2013, respectively, due to an increase in producer activity in our rich gas areas that will be partially offset by declining volumes in our lean gas areas.

The following table compares forecasted volumes of natural gas and crude oil gathered and NGLs and condensate produced on our systems for the twelve months ending December 31, 2014 to actual pro forma volumes for the year ended December 31, 2012 and the twelve months ended September 30, 2013.

	Pro Forma		Forecasted
	Year Ended December 31, 2012	Twelve Months Ended September 30, 2013	Twelve Months Ending December 31, 2014
Natural Gas – Gathered Volumes (TBtu/d)			
Anadarko system	1.1	1.3	1.5
Ark-La-Tex system	1.7	1.4	1.6(1)
Arkoma system	1.0	1.0	0.9(2)
Total	3.8	3.7	4.0
NGLs (MBbl/d)(3)			
Anadarko system	49.1	44.6	56.2
Ark-La-Tex system	5.8	10.4(4)	11.7
Arkoma system	8.0	5.0	4.2
Total	62.9	60.0	72.1
Condensate (MBbl/d)	2.4	2.8	3.0
Crude Oil — Gathered Volumes (MBbl/d)			
Williston system(5)	—	—	9.6

(1) Gathered volumes does not include approximately 0.7 TBtu/d not expected to be delivered but for which payments would be received in order for our customers to meet minimum volume commitments.
(2) Gathered volumes does not include approximately 0.1 TBtu/d not expected to be delivered but for which payments would be received in order for our customers to meet minimum volume commitments.
(3) Excludes condensate.
(4) Average daily NGL volumes increased primarily as a result of the addition of volumes associated with the July 31, 2012 acquisition of Waskom.
(5) Initial operation of the system began on November 1, 2013.

Anadarko Basin

Natural gas gathered volumes on our Anadarko system are expected to average 1.5 TBtu/d for the twelve months ending December 31, 2014, an increase of 36% and 15% as compared to the pro forma year ended December 31, 2012 and the pro forma twelve months ended September 30, 2013, respectively. The increases in volumes that are estimated to be gathered and processed in this basin are primarily associated with our customers' activity in the liquids-rich Greater Granite Wash, SCOOP and Mississippi Lime plays. Since January 2010, we have secured over 3.8 million gross acres dedicated via long-term contracts in this basin. We currently serve over 200 producers in this basin with total acreage dedications of over 4.7 million gross acres. In support of these long-term dedications and continued producer activity in this liquids-rich basin, we elected to expand the processing capacity on our Anadarko super header by 800 MMcf/d since January 2010. This strategic expansion was initiated to allow us to continue to provide reliable and efficient service to our customers. To date, we have installed half of that capacity and expect that we will commence operations at our 200 MMcf/d McClure processing plant in the first quarter of 2014 and our 200 MMcf/d Bradley plant in the first quarter of 2015.

Ark-La-Tex Basin

Natural gas gathered volumes on our Ark-La-Tex system are expected to average 1.6 TBtu/d for the twelve months ending December 31, 2014, a decrease of 6% and an increase of 14% as compared to the pro forma year ended December 31, 2012 and the pro forma twelve months ended September 30, 2013, respectively. We are forecasting increased volume associated with the relatively rich Cotton Valley play from increased drilling activity around our Waskom plant, as well as increased volumes due to recent drilling activity in the Haynesville shale play. Throughput on our systems in the lean Haynesville shale play is not expected to exceed our minimum volume commitments during the forecast period; therefore, we do not expect an increase in margin commensurate with the expected increase in volume. We currently serve over 110 producers and have secured over 0.7 million gross acres dedicated via long-term contracts in this basin. We believe that we are well-positioned to benefit from future increases in drilling activity in this basin.

Arkoma Basin

Natural gas gathered volumes on our Arkoma system are expected to average 0.9 TBtu/d for the twelve months ending December 31, 2014 compared to 1.0 TBtu/d for each of the pro forma year ended December 31, 2012 and the pro forma twelve months ended September 30, 2013. Volumes in this basin are primarily produced from the Fayetteville and Woodford shale plays and the traditional Arkoma basin. We expect producers' drilling activity to continue at a pace that will allow us to maintain consistent volumes through our gathering systems in the region. Throughput on our systems in the Arkoma Basin is not expected to exceed our minimum volume commitments during the forecast period. We currently serve over 220 producers and have secured 1.2 million acres dedicated via long-term contracts in this basin, which we believe positions us to benefit from future increases in drilling activity in this basin.

Williston

We estimate that we will gather an average of 9,600 Bbl/d of crude oil associated with our Williston system in the Bakken for the twelve months ending December 31, 2014. Initial operation of this system began on November 1, 2013. Construction associated with this project is ongoing and we expect it to be fully operational in the third quarter of 2014. Total capacity on the system once fully in-service will be 19,500 Bbl/d, all of which is contracted through 2028.

Transportation and Storage Gross Margin

We forecast our total transportation and storage gross margin to be $564 million for the twelve months ending December 31, 2014, compared to $591 million for the pro forma year ended December 31, 2012 and $563 million for the pro forma twelve months ended September 30, 2013. Of the $564 million of total transportation and storage gross margin for the twelve months ending December 31, 2014, we estimate we will generate $429 million from our interstate systems and $135 million from our intrastate systems.

Gross margin from our transportation and storage system is substantially fee-based in nature and is generated from (i) a transportation rate charged to firm transportation capacity commitments or interruptible transportation volumes, (ii) a storage rate charged based on firm storage capacity or interruptible storage volumes and (iii) other items including net fuel collections not subject to tracker mechanisms, net gas sales and other miscellaneous items. For the twelve months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 87% and 86% of the transportation and storage business segment gross margin, respectively, was derived from demand charges under firm contract arrangements. For the twelve months ending December 31, 2014, we assume 87% of the transportation and storage business segment gross margin is derived from demand charges under firm contract arrangements. Our cash flows in our transportation and storage business segment are not significantly impacted by commodity price fluctuations. The limited amount of direct commodity exposure we do have is derived from sales of natural gas and NGLs collected under our contractual arrangements or fuel charges net of the fuel used to run our compression facilities not subject to a fuel tracker system. We experience a limited amount of seasonal variability related to demand for our interruptible services in which fees are dependent upon throughput. Gross margin from interruptible services contributed approximately 12% and 11% of total segment gross margin for the pro forma twelve months ended December 31, 2012 and the pro forma twelve months ended September 30, 2013, respectively. For the twelve months ending December 31, 2014, we assume 10% of the transportation and storage business segment gross margin is derived from interruptible services.

We believe that the recent trend of decreasing revenues on our interstate and intrastate systems is stabilizing and that our revenues in future periods will be consistent with the levels that we have projected for the forecast period. The historical decline on our interstate systems has been primarily due to market conditions, including low basis spreads and producers and marketers not recontracting firm demand capacity. On our intrastate system, the primary driver of the decline in gross margin has been the result of integrity outage refunds, lower crosshaul revenues, lower transportation allocations from gathering contracts and lower transportation and storage spreads. We believe lower basis spreads to be an industry-wide phenomenon, but one that has stabilized. We have begun to see renewed interest by producers for capacity on our systems as well as a slight recovery in recontracting rates as evidenced by expansions we expect to place into service during 2014. Additionally, 55% of our total transportation and storage gross margin for the twelve months ending December 31, 2014 is expected to be derived from customers holding firm demand capacity who are users of natural gas and rely on our systems to obtain natural gas for their operations such as LDCs, power generation and industrial customers. We believe these customers will tend to renew contracts at or near their existing reserved capacity based on historical renewal patterns and their per-period requirements.

As of September 30, 2013 our weighted-average contract life for firm transportation volumes on our interstate and intrastate pipelines was 4.1 and 5.4 years, respectively, and 4.7 years on our firm storage contracts.

Interstate

- EGT: For the twelve months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 56% and 52% of total transportation and storage business segment gross margins, respectively, were derived from demand charges under EGT’s firm contract arrangements. In the forecast period, we assume 52% of total transportation and storage business segment gross margin is derived from demand charges under firm EGT contract arrangements. As of September 30, 2013, approximately 83% of EGT’s capacity was under contract with an average remaining contract life of 4.3 years. Our forecast also includes increased revenues from expansion projects that are expected to be placed into service during 2014.

- MRT: For the twelve months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 10% and 12%, respectively, of total transportation and storage business segment gross margins was derived from demand charges under MRT’s firm contract arrangements. In the forecast period, we assume 15% of total transportation and storage business segment gross margin is derived from demand charges under firm MRT contract arrangements. As of September 30, 2013, approximately 94% of MRT's capacity was under contract with an average remaining contract life of 3.5 years. In September 2013, the FERC approved a rate settlement with our MRT system customers and our forecast reflects the resulting higher revenues.

Intrastate

For the twelve months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 21% and 22%, respectively, of our total transportation and storage business segment gross margin was generated under firm intrastate transportation and storage contract arrangements. In the forecast period, we assume 20% of our total transportation and storage business segment gross margin is derived from firm intrastate transportation and storage contract arrangements. As of September 30, 2013, the average remaining contract life for our intrastate transportation customers was 5.4 years. We believe that our intrastate assets are well-positioned to continue to provide a unique service offering to our customers and to benefit from the forecasted growth in our gathered volumes across the Anadarko and Arkoma basins.

Storage

Gross margin related to storage is included in the interstate and intrastate portions of our transportation and storage business segments. Our interstate and intrastate storage assets expand the range of services we can offer to our interstate and intrastate transportation customers and provide operational flexibility for our transportation systems. As reflected in the interstate and intrastate gross margin above, for both the twelve months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 9% of our total transportation and storage business segment gross margin was generated from firm storage capacity contracts. In the forecast period, we assume 10% of transportation and storage business segment gross margin is derived from firm storage demand charges. As of September 30, 2013, approximately 79% of our storage capacity was under firm storage capacity contracts with an average remaining contract life of 4.7 years.

Equity in Earnings of Equity Method Affiliates

We own a 24.95% interest in SESH and operate the pipeline. We have the ability to acquire CenterPoint Energy's remaining 25.05% of SESH by 2015. As of September 30, 2013, the system had capacity to transport 1.5 Bcf/d of natural gas from Perryville, Louisiana to Gwinville, Mississippi, and 1.0 Bcf/d of natural gas to the pipeline's end point in Alabama. As of September 30, 2013, 100% of SESH's capacity was under contract with an average remaining contract life of 11.5 years. In the forecast period, we assume additional 2014 earnings from expansion projects.

Operation and Maintenance Expenses

Our operation and maintenance expenses are comprised primarily of labor expenses, lease costs, utility costs, insurance premiums, and repairs and maintenance expenses. We estimate that we will incur operation and maintenance expense of $509 million for the twelve months ending December 31, 2014 as compared to $449 million and $492 million for the year ended December 31, 2012 and the twelve months ended September 30, 2013, respectively, each on a pro forma basis. The increase in operation and maintenance expenses compared to the historical periods is primarily driven by expected integration costs, increased costs for labor and benefits and expenses attributable to acquired assets and new assets placed in service. The forecast and pro forma amounts above include an estimated $3 million of incremental operation and maintenance expenses that we expect to incur as a result of being a separate publicly traded partnership, which are not reflected in our unaudited pro forma financial statements.

Depreciation and Amortization

We estimate that our depreciation and amortization expense will be $291 million for the twelve months ending December 31, 2014, as compared to $273 million and $280 million for the year ended December 31, 2012 and the twelve months ended September 30, 2013, respectively, each on a pro forma basis. The expected increase is attributable to additional assets placed in service. Depreciation and amortization expense is based on consistent average depreciable asset lives and depreciation methodologies.

Taxes Other Than Income

Our taxes other than income expenses are comprised primarily of property taxes and sales and use taxes. We estimate that our taxes other than income expense will be $65 million for the twelve months ending December 31, 2014, as compared to $57 million and $56 million for the year ended December 31, 2012 and the twelve months ended September 30, 2013, respectively, each on a pro forma basis. The expected increase is primarily attributable to additional assets placed in service.

Capital Expenditures

We estimate that total capital expenditures for the twelve months ending December 31, 2014 will be $647 million, as compared to pro forma capital expenditures of $1.1 billion and $762 million for the year ended December 31, 2012 and the twelve months ended September 30, 2013, respectively, each on a pro forma basis. This forecast estimate is based on the following assumptions:

Maintenance Capital Expenditures

We estimate that our maintenance capital expenditures will be approximately $199 million for the twelve months ending December 31, 2014, of which $67 million will relate to pipeline integrity and multi-year replacement projects, and $132 million will relate to other routine maintenance projects as well as integration projects, including technology integration projects. Approximately $53 million of the estimated maintenance capital expenditures for the twelve months ending December 31, 2014 are related to our gathering and processing business segment, while the balance is related to our transportation and storage business segment. Maintenance capital expenditures were $167 million and $186 million for the year ended December 31, 2012 and for the twelve months ended September 30, 2013, respectively, each on a pro forma basis. We believe the forecasted amount for the twelve months ending December 31, 2014 is generally indicative of the annual maintenance capital requirement going forward, although we anticipate variability in levels of maintenance capital expenditures in both of our business segments due to occasional unpredictable expenses. Our estimate of maintenance capital expenditures for the twelve months ending December 31, 2014 is higher than historical maintenance capital expenditures primarily due to higher gathering and processing system maintenance associated with the growth of our systems, integration projects planned pipeline replacement projects, and expected increases in compliance costs related to pipeline safety rules.

Expansion Capital Expenditures

We estimate that our expansion capital expenditures will be $448 million for the twelve months ending December 31, 2014 as compared to expansion capital expenditures of $912 million (including $439 million of acquisition expenditures) and $576 million for the pro forma year ended December 31, 2012 and the twelve months ended September 30, 2013, respectively. Approximately $429 million of the estimated expansion capital expenditures for the twelve months ending December 31, 2014 are related to our gathering and processing business segment, while the balance is related to our transportation and storage business segment. These forecasted expansion capital expenditures are primarily comprised of the following projects:

- Approximately $345 million of our forecasted expansion capital expenditures are related to the expansion of our Anadarko gathering and processing system where we expect continued volume growth associated with our long-term gathering and processing agreements in these areas. Nearly 40% of this amount is related to our McClure Plant and Bradley Plant, which are expected to be placed into service in the first quarter of 2014 and the first quarter of 2015, respectively. The balance of the expansion capital expenditures are associated with gathering infrastructure, such as pipeline and compression, in support of new volumes.

- We expect the balance of our gathering and processing expansion capital expenditures to be spent in the forecast period across the other basins in which we operate with approximately $63 million of enhancements to our processing facilities and additional gathering infrastructure for new volumes in the Ark-La-Tex basin, $6 million of additional gathering infrastructure to accommodate the volumes from the Arkoma basin, and $15 million of crude gathering infrastructure associated with our Bakken crude gathering system in the Williston basin.
- We expect to spend approximately $19 million of expansion capital expenditures related to our transportation and storage business segment. These expenditures are associated with projects that will serve additional industrial markets or new supply.

We have only included expansion capital expenditures that are associated with identified projects in the forecast period. We believe that we will continue to identify new expansion capital projects and acquisition opportunities that may increase the amount of expansion capital expenditures beyond what we are currently forecasting for the twelve months ending December 31, 2014.

Although we may make acquisitions during the twelve months ending December 31, 2014, our forecast does not reflect any acquisitions, as we cannot assure you that we will be able to identify attractive acquisition opportunities or, if identified, that we will be able to negotiate acceptable purchase agreements.

Investment in Equity Method Affiliates

We expect to invest approximately $6 million during 2014 for our share of a planned expansion project at SESH. We have not included the potential impact of CenterPoint Energy's exercising its option to contribute an additional 24.95% interest in SESH to us in May 2014. Under the master formation agreement, CenterPoint Energy has certain put rights, and we have certain call rights, exercisable with respect to CenterPoint Energy's remaining interest in SESH. Please read "Certain Relationships and Related Party Transactions—Master Formation Agreement—Acquisition of Remaining CenterPoint Energy Interest in SESH."

Financing

We estimate that interest paid for the twelve months ending December 31, 2014 will be $94 million, as compared to interest paid of $55 million and $57 million for the pro forma year ended December 31, 2012 and the pro forma twelve months ended September 30, 2013, respectively. The primary driver of the increase in interest paid for the twelve months ending December 31, 2014 versus the prior periods is associated with expected higher interest rates on the $1.5 billion refinancing in 2014 described below. Our forecast for the twelve months ending December 31, 2014 is based on the following significant financing assumptions:

- for purposes of our forecast for the twelve months ending December 31, 2014, we have assumed that the closing of this offering takes place on January 1, 2014;
- we expect to have average borrowings of approximately $104 million under our $1.4 billion revolving credit facility during the forecast period, which we will use along with proceeds from the offering to fund our forecasted expansion capital expenditures during the twelve months ending December 31, 2014;
- we have assumed the borrowings under our revolving credit facility will bear interest at an average rate of 1.9% through December 31, 2014;
- we have assumed the issuance of $1.5 billion of long-term notes in the first half of 2014 at a weighted average interest rate of approximately 4.6% associated with an expected refinancing of our aggregate $1.3 billion of outstanding term loans that have a weighted average interest rate of approximately 1.9%, as well as the $200 million aggregate principal amount of 6.875% senior notes that mature in mid-2014;

- we have assumed that we will have other senior notes and long-term notes payable with a face amount averaging $713 million with a weighted average cash interest rate of 5.2%; and
- we expect to remain in compliance with the financial and other covenants in our credit facilities.

Regulatory, Industry and Economic Factors

Our forecast for the twelve months ending December 31, 2014 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 portions of the energy industry in which we operate, or a new interpretation of existing regulation, that will be materially adverse to our business;
- there will not be any major adverse change in the portions of the midstream energy industry that we serve or in general economic conditions, including in the levels of natural gas and crude oil production and demand in the geographic areas that we serve;
- there will not be any material accidents, weather-related incidents, unscheduled downtime or similar unanticipated events with respect to our facilities or those of third parties on which we depend;
- we will not make any acquisitions or other significant expansion capital expenditures (other than as described above);
- there will not be a shortage of skilled labor; and
- market, insurance and overall economic conditions will not change substantially.

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 after the closing of this offering, beginning with the quarter ending , we distribute all of our available cash to unitholders of record on the applicable record date. We will adjust the amount of our distribution for the period from the closing of this offering through , based on the actual length of the period.

Definition of Available Cash

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- *less*, the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business (including cash reserves for our future capital expenditures and anticipated future debt service requirements and refunds of collected rates reasonably likely to be refunded as a result of a settlement or hearing related to FERC rate proceedings or rate proceedings under applicable law subsequent to that quarter);
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);
- *plus*, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

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 twelve months with funds other than from additional working capital borrowings.

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 $ per unit 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" for a discussion of the restrictions included in our credit agreements that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights

Our general partner owns a non-economic general partner interest in us and thus will not be entitled to distributions that we make prior to our liquidation in respect of such general partner interest. Our general partner 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% does not include any distributions that our general partner or its affiliates may receive on common units or subordinated units that they own. Please read "—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; *plus*
- all of our cash receipts after the closing of this offering, excluding cash from interim capital transactions (as defined below) and the termination of hedge contracts, provided that cash receipts from the termination of a commodity hedge or interest rate hedge prior to its specified termination date shall be included in operating surplus in equal quarterly installments over the remaining scheduled life of such commodity hedge or interest rate hedge; *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 (including incremental distributions on incentive distribution rights) paid in respect of equity issued, other than equity issued in this offering, to finance all or a portion of expansion capital expenditures in respect of the period from the date that we enter into a binding obligation to commence the construction, development, replacement, improvement or expansion of a capital asset and ending on the earlier to occur of the date the capital asset commences commercial service and the date that it is abandoned or disposed of; *plus*
- cash distributions (including incremental distributions on incentive distribution rights) paid in respect of equity issued, other than equity issued in this offering, to pay interest and related fees on debt incurred, or to pay distributions on equity issued, to finance the expansion capital expenditures referred to in the prior bullet; *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 twelve months after having been incurred or repaid within such twelve-month period with the proceeds of additional working capital borrowings; *less*

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- 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 our 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.

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 twelve-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.

We define interim capital transactions as (i) borrowings, refinancings or refundings of indebtedness (other than working capital borrowings and items purchased on open account or for a deferred purchase price in the ordinary course of business) and sales of debt securities, (ii) issuances of equity securities and (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 normal asset retirements or replacements.

We define operating expenditures as all of our cash expenditures, including, but not limited to, taxes, reimbursements of expenses of our general partner and its affiliates, director, officer and employee compensation, debt service payments, payments made in the ordinary course of business under interest rate hedge contracts and commodity hedge contracts (provided that payments made in connection with the termination of any interest rate hedge contract or commodity hedge contract prior to the expiration of its settlement or termination date specified therein 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 and amounts paid in connection with the initial purchase of a rate hedge contract or a commodity hedge contract will be amortized at the life of such rate hedge contract or commodity hedge contract), maintenance capital expenditures (as discussed in further detail below) and repayment of working capital borrowings; 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;
- expansion capital expenditures;
- investment capital expenditures;
- payment of transaction expenses (including taxes) relating to interim capital transactions;
- distributions to our partners;
- repurchases of partnership interests (excluding repurchases we make to satisfy obligations under employee benefit plans); or
- any other expenditures or payments made using the proceeds of this offering.

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

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. Examples of expansion capital expenditures include the acquisition of equipment and the construction, development or acquisition of additional pipeline, storage, gathering or processing capacity to the extent such capital expenditures are expected to expand our operating capacity or our operating income. Expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of expansion capital expenditures in respect of the period from the date that we enter into a binding obligation to commence the construction, development, replacement, improvement or expansion of a capital asset 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.

Maintenance capital expenditures are cash expenditures (including expenditures for the construction or development of new capital assets or the replacement, improvement or expansion of existing capital assets) made to maintain, over the long-term, our operating capacity or operating income. Examples of maintenance capital expenditures are expenditures to repair, refurbish and replace pipelines, to connect additional wells to our own gathering system to offset material declines, to maintain equipment reliability, integrity and safety and to address environmental laws and regulations. Maintenance capital expenditures are included in operating expenditures and thus will reduce operating surplus.

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 our operating capacity or operating income over the long term.

Capital expenditures that are made in part for maintenance capital purposes, investment capital purposes and/or expansion capital purposes will be allocated as maintenance capital expenditures, investment capital expenditures or expansion capital expenditure by our general partner.

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 following the distribution of available cash in respect of any quarter beginning with the first quarter ending , 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 $ per unit (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 the sum of $ (the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during those periods on a fully diluted basis; 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 following the distribution of available cash in respect of any quarter beginning with the first quarter ending , 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% of the annualized minimum quarterly distribution) for the four-consecutive-quarter period immediately preceding that date;
- the adjusted operating surplus (as defined below) generated during the four-consecutive-quarter period immediately preceding that date equaled or exceeded the sum of (i) $ per unit (150% of the annualized minimum quarterly distribution) on all of the outstanding common units and subordinated units during that period on a fully diluted basis and (ii) the corresponding distributions on the incentive distribution rights; and
- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Expiration Upon Removal of the General Partner

In addition, if the unitholders remove our general partner other than for cause:

- 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;

- 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; 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.

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.

Adjusted Operating Surplus

Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes 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; *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*, to the common unitholders, pro rata, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
- *second*, to the common unitholders, pro rata, 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*, to the subordinated unitholders, pro rata, 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 "—Incentive Distribution Rights" below.

The preceding discussion is based on the assumption 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*, to all unitholders, pro rata, 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 "—Incentive Distribution Rights" below.

The preceding discussion is based on the assumption that we do not issue additional classes of equity securities.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage (15.0%, 25.0% and 50.0%) 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 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*, to all unitholders, pro rata, 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 (through the incentive distribution rights) 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 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 assume that 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	$		100.0%	0.0%
First Target Distribution	up to $		100.0%	0.0%
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, subject to certain conditions, 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, if 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 and the amount of each such distribution did not exceed adjusted operating surplus for such quarter, respectively. 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 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.

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 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 common 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*, to all unitholders, pro rata, 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 allocations 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 completion 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	Marginal Percentage Interest in Distributions: General Partner	Quarterly Distribution per Unit Following Hypothetical Reset	
Minimum Quarterly Distribution	$		100.0%	0.0%	$	
First Target Distribution	up to $		100.0%	0.0%	up to $ [1]	
Second Target Distribution	above $	up to $	85.0%	15.0%	above $0.	up to $0. [2]
Third Target Distribution	above $	up to $	75.0%	25.0%	above $0.	up to $0. [3]
Thereafter	above $		50.0%	50.0%	above $0. [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, in respect of incentive distribution rights, or IDRs, based on an average of the amounts distributed for the two quarters immediately prior to the reset. The table assumes that immediately prior to the reset there would be common units outstanding and that the average distribution to each common unit would be $ for the two consecutive non-overlapping quarters prior to the reset.

	Prior to Reset					
			General Partner Cash Distributions			
	Quarterly Distribution per Unit	Common Unitholders Cash Distributions	Common Units	IDRs	Total	Total Distribution
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 the general partner, in respect of IDRs, with respect to the quarter after the reset occurs. The table reflects that as a result of the reset there would be common units outstanding, and that the average distribution to each common unit would be $. The number of common units issued as a result of the reset was calculated by dividing (x) $ as the average of the amounts received by the general partner in respect of its IDRs for the two consecutive non-overlapping quarters prior to the reset as shown in the table above by (y) the average of the cash distributions made on each common unit per quarter for the two consecutive non-overlapping quarters prior to the reset as shown in the table above, or $.

	After Reset					
			General Partner Cash Distributions			
	Quarterly Distribution per Unit	Common Unitholders Cash Distributions	Common Units Issued As a Result of the Reset	IDRs	Total	Total Distribution
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.

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*, to all unitholders, pro rata, until the minimum quarterly distribution is reduced to zero, as described below under "—Effect of a Distribution from Capital Surplus";
- *second*, to the common unitholders, pro rata, 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 such distributions were from operating surplus.

The preceding discussion is based on the assumption 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 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 the holder of our 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;
- target distribution levels;
- the unrecovered initial unit price; and
- the arrearages in payment of the minimum quarterly distribution on the common units.

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 50.0% of its initial level, and each subordinated unit would be split into two subordinated 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 the official interpretation of existing law is modified 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 shall be reduced by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter (reduced by the amount of the estimated tax liability for such quarter payable by reason of such legislation or interpretation) and the denominator of which is the sum of available cash for that quarter (reduced by the amount of the estimated tax liability for such quarter payable by reason of such legislation or interpretation) 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 may 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 to the extent of any negative balance in its capital account;
- *second*, to the common unitholders, pro rata, 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*, to the subordinated unitholders, pro rata, 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*, to all common and subordinated unitholders, pro rata, 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 to the common and subordinated unitholders, pro rata, for each quarter of our existence;
- *fifth*, 85.0% to all common and subordinated 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 common and subordinated unitholders, pro rata, and 15.0% to our general partner for each quarter of our existence;

- *sixth*, 75.0% to all common and subordinated 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 common and subordinated unitholders, pro rata, and 25.0% to our general partner for each quarter of our existence; and
- *thereafter*, 50.0% to all common and subordinated 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*, to holders of subordinated units in proportion to the positive balances in their capital accounts until the capital accounts of the subordinated unitholders have been reduced to zero;
- *second*, to the holders of common units in proportion to the positive balances in their capital accounts 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.

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.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following tables set forth, for the periods and as of the dates indicated, the selected historical financial and operating data of Enable Midstream Partners, LP, which is derived from the historical books and records of the partnership, the selected historical financial and operating data of Enogex, which is derived from the historical books and records of Enogex, and the pro forma financial and operating data of Enable Midstream Partners, LP. On May 1, 2013 (formation), OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the partnership in exchange for common units and, for OGE Energy only, interests in our general partner. The transaction was considered a business combination for accounting purposes, with the partnership considered the acquirer of Enogex. Subsequent to May 1, 2013, the financial and operating data of the partnership are consolidated to reflect the acquisition of Enogex and the retention of certain assets and liabilities by CenterPoint Energy. The following tables should be read together with, and are qualified in their entirety by reference to, the historical and unaudited pro forma combined and consolidated financial statements, as applicable, and the accompanying notes included elsewhere in this prospectus.

The selected historical financial and operating data of Enable Midstream Partners, LP for the years ended December 31, 2012, 2011 and 2010 and balance sheet data as of December 31, 2012 and 2011 is derived from and should be read in conjunction with the audited historical combined financial statements of the partnership included elsewhere in this prospectus. The selected historical financial and operating data of Enable Midstream Partners, LP for the nine months ended September 30, 2013 and 2012 and balance sheet data as of September 30, 2013 is derived from and should be read in conjunction with the unaudited historical condensed combined and consolidated financial statements included elsewhere in this prospectus. The selected historical financial data of Enable Midstream Partners, LP as of December 31, 2009 and 2008 and for the years ended December 31, 2009 and 2008 are derived from the partnership's unaudited historical combined financial statements that are not included in this prospectus. The operating data for all periods is unaudited. The following table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

The selected unaudited pro forma financial and operating data is derived from and should be read in conjunction with the unaudited pro forma combined financial statements of Enable Midstream Partners, LP included elsewhere in this prospectus. The pro forma balance sheet assumes that the offering occurred as of September 30, 2013 and the pro forma condensed combined statements of income for the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012 assume that our formation transactions and this offering, with respect to unit and per unit information, occurred as of January 1, 2012. These transactions include, and the pro forma financial data gives effect to, the following:

- The acquisition of Enogex on May 1, 2013, including (1) the incremental depreciation and amortization incurred on the fair value adjustment of Enogex's assets, (2) adjustments to revenue and cost of sales to reflect purchase price adjustments for the recurring impact of certain loss contracts and deferred revenues and (3) a reduction to interest expense for recognition of a premium on Enogex's fixed rate senior notes;
- A reduction in the historical interest income received on the notes receivable—affiliated companies from CenterPoint Energy, which were paid off at formation, and the interest expense incurred on notes payable—affiliated companies to CenterPoint Energy and OGE Energy prior to May 1, 2013, which were repaid at formation;
- The entrance into a $1.05 billion 3-year senior unsecured term loan facility by the partnership and the incremental interest expense and amortization of deferred financing costs related thereto;
- The entrance into a $1.4 billion senior unsecured revolving credit facility by the partnership and the incremental interest expense and amortization of deferred financing costs related thereto;
- A reduction for the elimination of federal and state income taxes, except for Texas state margin taxes;
- A reduction in the partnership's interest in SESH from 50% to 24.95%;

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- The consummation of this offering and our issuance of common units to the public and the conversion of common units of CenterPoint Energy and common units of OGE Energy into subordinated units; and
- The application of the net proceeds of this offering as described in "Use of Proceeds."

The pro forma financial data does not give effect to the estimated $3 million in incremental annual operation and maintenance expense we expect to incur as a result of being a publicly traded partnership. The unaudited pro forma adjustments do not give effect to any potential cost savings or other operating efficiencies from the integration of the partnership and Enogex. The pro forma financial data does not reflect adjustments for the execution of service agreements with CenterPoint Energy and OGE Energy upon formation since the costs under these service agreements were previously incurred by the partnership and Enogex on a similar basis. The pro forma financial data does not adjust for acquisition related costs since the partnership incurred no acquisition related costs in the Condensed Combined and Consolidated Statement of Income during any period presented based upon the terms in the master formation agreement. For a description of the step acquisition gain, please refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Pro Forma."

The following tables include the financial measures of gross margin, which we use as a measure of performance, Adjusted EBITDA, which we use as a measure of performance and liquidity, and distributable cash flow, which we use as a measure of liquidity. Gross margin, Adjusted EBITDA and distributable cash flow are not calculated and presented in accordance with GAAP. We define gross margin as total revenues minus cost of goods sold, excluding depreciation and amortization. We define Adjusted EBITDA as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results. For a reconciliation of gross margin, Adjusted EBITDA and distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please see "—Non-GAAP Financial Measures."

	Enable Midstream Partners, LP Historical							Enable Midstream Partners, LP Pro Forma		
	Year Ended December 31,					Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,	
	2012	2011	2010	2009	2008	2013	2012	2012	2013	2012
	(In millions, except for unit, per unit and operating data)									
Results of Operations Data:										
Revenues	$ 952	$ 932	$ 871	$ 813	$ 937	$ 1,665	$ 686	$ 2,564	$ 2,296	$ 1,866
Cost of goods sold, excluding depreciation and amortization	129	101	98	131	221	827	75	1,238	1,312	882
Operation and maintenance	267	263	233	242	199	302	191	446	366	323
Depreciation and amortization	106	91	77	63	58	148	78	273	205	198
Impairments	—	—	—	—	—	12	—	—	12	—
Gain on insurance proceeds	—	—	—	—	—	—	—	(8)	—	(8)
Taxes other than income	34	37	37	35	26	37	28	57	45	46
Operating income	416	440	426	342	433	339	314	558	356	425
Interest expense	(85)	(90)	(83)	(72)	(71)	(53)	(65)	(45)	(35)	(33)
Equity in earnings of equity method affiliates	31	31	29	29	35	12	25	18	9	15
Interest income—affiliated companies	21	14	9	10	23	9	15	—	—	—
Step acquisition gain	136	—	—	—	—	—	136	136	—	136
Other, net	—	—	(2)	1	1	—	1	(4)	9	—
Income before income taxes	519	395	379	310	421	307	426	663	339	543
Income tax expense (benefit)	203	163	155	113	159	(1,195)	160	3	1	2
Net income	$ 316	$ 232	$ 224	$ 197	$ 262	$ 1,502	$ 266	$ 660	$ 338	$ 541
Less: Net income attributable to noncontrolling interest	—	—	—	—	—	2	—	2	2	2
Net income attributable to Enable Midstream Partners, LP	$ 316	$ 232	$ 224	$ 197	$ 262	$ 1,500	$ 266	$ 658	$ 336	$ 539
Number of outstanding limited partner units										
Basic and diluted earnings per limited partner unit										
Balance Sheet Data (at period end):										
Property, plant and equipment, net	$ 4,705	$ 4,070	$ 3,876	$ 3,198	$ 2,753	$ 8,831	$ 4,655			
Total assets	6,482	5,796	5,463	4,534	4,366	10,950	6,442			
Long-term debt, including current portion	1,762	1,568	1,671	1,179	1,294	2,295	1,789			
Enable Midstream Partners, LP Partners' Capital	3,215	2,898	2,666	2,442	2,245	8,152	3,167			
Cash Flow Data:										
Net cash flows provided by (used in):										
Operating activities	$ 451	$ 662	$ 308	$ 306	$ 351	$ 472	$ 357			
Investing activities	(645)	(560)	(800)	(195)	(683)	63	(576)			
Financing activities	194	(102)	492	(111)	332	(511)	221			
Other Financial Data:										
Gross margin	$ 823	$ 831	$ 773	$ 682	$ 716	$ 838	$ 611	$ 1,326	$ 984	$ 984
Adjusted EBITDA	$ 561	$ 570	$ 543	$ 440	$ 493	$ 517	$ 424	$ 837	$ 586	$ 628
Distributable cash flow								$ 612	$ 414	$ 477
Operating Data:										
Gathered volumes—TBtu	874	794	647	426	421	801	663	1,391	985	1,041
Gathered volumes—TBtu/d	2.39	2.17	1.77	1.17	1.15	3.62	2.42	3.80	3.61	3.80
Natural gas processed volumes—TBtu	80	47	57	22	26	270	44	437	397	306
Natural gas processed volumes—TBtu/d	0.22	0.13	0.16	0.06	0.07	1.48	0.16	1.20	1.46	1.12
Total NGLs sold—millions of gallons/d	0.25	0.09	0.12	0.14	0.07	1.66	0.20	2.64	2.49	2.58
Transported volumes—TBtu	1,378	1,596	1,704	1,610	1,551	1,277	1,034	2,139	1,537	1,596
Transportation volumes—TBtu/d	3.76	4.37	4.67	4.41	4.24	4.32	3.77	5.36	5.05	5.37
Interstate firm contracted capacity—Bcf/d	7.30	7.33	7.44	7.13	7.30	7.17	7.37	7.30	7.17	7.37
Intrastate average deliveries—TBtu/d	—	—	—	—	—	0.90	—	1.60	1.59	1.60

Non-GAAP Financial Measures

For a discussion of the non-GAAP financial measures of Adjusted EBITDA, distributable cash flow and gross margin, please read “Summary—Summary Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures.” The following table presents a reconciliation of (i) gross margin to revenues, (ii) Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest and (iii) Adjusted EBITDA to net cash provided by operating activities, in each case, the most directly comparable GAAP financial measures, on a historical basis and pro forma basis, as applicable, for each of the periods indicated.

	Enable Midstream Partners, LP Historical					Enable Midstream Partners, LP Historical		Enable Midstream Partners, LP Pro Forma		
	Year Ended December 31,					Nine months Ended September 30, 2013		Year Ended December 31,	Nine Months Ended September 30,	
	2012	2011	2010	2009	2008	2013	2012	2012	2013	2012
	(In millions)									
Reconciliation of Gross Margin to Revenue:										
Revenues	$ 952	$ 932	$ 871	$ 813	$ 937	$ 1,665	$ 686	$ 2,564	$ 2,296	$ 1,866
Cost of goods sold, excluding depreciation and amortization	129	101	98	131	221	827	75	1,238	1,312	882
Gross margin	$ 823	$ 831	$ 773	$ 682	$ 716	$ 838	$ 611	$ 1,326	$ 984	$ 984
Reconciliation of Adjusted EBITDA and distributable cash flow to net income attributable to controlling interest:										
Net income attributable to Enable Midstream Partners, LP	$ 316	$ 232	$ 224	$ 197	$ 262	$ 1,500	$ 266	$ 658	$ 336	$ 539
Add:										
Depreciation and amortization expense	106	91	77	63	58	148	78	273	205	198
Interest expense, net of interest income	64	76	74	62	48	44	50	45	35	33
Income tax expense (benefit)	203	163	155	113	159	(1,195)	160	3	1	2
EBITDA	$ 689	$ 562	$ 530	$ 435	$ 527	$ 497	$ 554	$ 979	$ 577	$ 772
Add:										
Impairment	—	—	—	—	—	12	—	—	12	—
Distributions from equity method affiliates	39	39	42	34	1	20	31	20	16	15
Less:										
Equity in earnings of equity method affiliates	(31)	(31)	(29)	(29)	(35)	(12)	(25)	(18)	(9)	(15)
Gain on insurance proceeds	—	—	—	—	—	—	—	(8)	—	(8)
Gain on disposition	—	—	—	—	—	—	—	—	(10)	—
Step acquisition gain	(136)	—	—	—	—	—	(136)	(136)	—	(136)
Adjusted EBITDA	$ 561	$ 570	$ 543	$ 440	$ 493	$ 517	$ 424	$ 837	$ 586	$ 628
Less:										
Adjusted interest expense, net								(55)	(43)	(41)
Expansion capital expenditures								(912)	(405)	(741)
Maintenance capital expenditures								(167)	(127)	(108)
Incremental operation and maintenance expense of being a public entity								(3)	(2)	(2)
Demand fees associated with legacy marketing business loss contracts								(10)	(8)	(8)
Add:										
Borrowings to fund demand fees associated with legacy marketing business loss contracts								10	8	8
Borrowings for expansion capital expenditures								912	405	741
Distributable cash flow								$ 612	$ 414	$ 477
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:										
Net cash provided by operating activities	$ 451	$ 662	$ 308	$ 306	$ 351	$ 472	$ 357			
Interest expense, net of interest income	64	76	74	62	48	44	50			
Net income attributable to noncontrolling interest	—	—	—	—	—	(2)	—			
Income tax expense (benefit)	203	163	155	113	159	(1,195)	160			
Deferred income tax (expense) benefit	(196)	(176)	(184)	(163)	(65)	1,197	(132)			
Equity in earnings of equity method affiliates, net of distributions	(8)	(8)	(13)	18	34	(8)	(6)			
Impairment	—	—	—	—	—	(12)	—			
Step acquisition gain	136	—	—	—	—	—	136			
Gain on insurance proceeds										
Other non-cash items	—	—	—	—	—	(2)	—			
Changes in operating working capital which (provided) used cash:										
Accounts receivable	8	(73)	87	5	5	39	32			
Accounts payable	6	(6)	(12)	45	(41)	(10)	(24)			
Other, including changes in noncurrent assets and liabilities	25	(76)	115	49	36	(26)	(19)			
EBITDA	$ 689	$ 562	$ 530	$ 435	$ 527	$ 497	$ 554			
Add:										
Impairment	—	—	—	—	—	12	—			
Distributions from equity method affiliates	39	39	42	34	1	20	31			
Less:										
Equity in earnings of equity method affiliates	(31)	(31)	(29)	(29)	(35)	(12)	(25)			
Step acquisition gain	(136)	—	—	—	—	—	(136)			
Adjusted EBITDA	$ 561	$ 570	$ 543	$ 440	$ 493	$ 517	$ 424			

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

The following discussion and analysis should be read in conjunction with the "Selected Historical and Pro Forma Financial and Operating Data" and the accompanying financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Please read "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements." In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

General. *We were formed in May 2013 by affiliates of CenterPoint Energy, OGE Energy and ArcLight. Pursuant to a master formation agreement, the following transactions occurred in connection with our formation:*

- *CenterPoint Energy converted CEFS into a Delaware limited partnership, which subsequently changed its name to Enable Midstream Partners, LP;*
- *CenterPoint Energy contributed certain equity interests in its subsidiaries that conduct the remaining portions of its midstream business to Enable Midstream Partners, LP; and*
- *OGE Energy and ArcLight contributed 100% of the equity interests in Enogex to Enable Midstream Partners, LP.*

The transaction was considered a business combination for accounting purposes, with the partnership considered as the acquirer of Enogex. As a result, the historical financial statements included elsewhere in this prospectus reflect the assets, liabilities and operations of the entities comprising CenterPoint Energy's interstate pipelines and field services reportable business segments for periods ending prior to May 1, 2013 and the consolidated assets, liabilities and operations of these entities and Enogex for periods ending on or after May 1, 2013. With respect to these historical periods, we refer to CenterPoint Energy's Interstate Pipelines segment as our Transportation and Storage segment and CenterPoint Energy's Field Services segment as our Gathering and Processing segment.

Supplemental Pro Forma Discussion. *The discussion of our historical interim results below includes a supplemental discussion of changes in the periods reflected in our pro forma financial statements, including the pro forma adjustments described under "Unaudited Pro Forma Condensed Combined Financial Statements."*

Overview

We are a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. We serve key current and emerging production areas in the United States, including several premier, unconventional shale resource plays and local and regional end-user markets in the United States. Our assets and operations are organized into two business segments: (i) gathering and processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. In both business segments, we generate a substantial portion of our gross margin under long-term, fee-based agreements that minimize our direct exposure to commodity price fluctuations.

Our natural gas gathering and processing assets are strategically located in four states and serve natural gas production from some of the most productive shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. These basins have experienced a strong increase in investment and drilling activity by exploration and production companies in recent years. We also own an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. We are continuing to construct additional crude oil gathering capacity in this area. Our natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Upon our formation in May 2013 as a limited partnership among OGE Energy, CenterPoint Energy and ArcLight, we became one of the largest midstream partnerships in the United States based on total assets. As of September 30, 2013, our portfolio of energy infrastructure assets included approximately 11,000 miles of gathering pipelines, 11 major processing plants with approximately 1.9 Bcf/d of processing capacity, approximately 7,800 miles of interstate pipelines (including SESH), approximately 2,300 miles of intrastate pipelines and eight storage facilities comprising 86.5 Bcf of storage capacity. We believe our scale benefits our customers by providing them with fully integrated midstream services and improved access from the wellhead to the marketplace. In addition, we believe our scale and scope will position us to be more competitive in developing new energy infrastructure assets and adding complementary services and business lines.

Our Operations

Our results are driven primarily by the volumes of natural gas that we gather, process and transport across our systems. From the year ended December 31, 2010 through the nine month period ended September 30, 2013, on a pro forma basis, we grew the average daily volume of natural gas gathered on our systems by 17%. Increases in gathered volumes also drive increases in processed volumes. Over the same periods, the average daily volume of gas processed on our systems grew by 49% on a pro forma basis. For both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, we generated approximately 75% of our gross margin under fee-based agreements.

Our footprint extends across both rich and lean natural gas and crude oil regions and we believe that our gathering and processing systems are well positioned to capture additional volumes from increased producer activity in these regions in the future.

As of September 30, 2013, our gathering agreements that have acreage dedications have original terms ranging from one to 15 years. These agreements generally require that production by our customers within the acreage dedication be delivered to our gathering system. As of September 30, 2013, these agreements had acreage dedications covering approximately 6.6 million gross acres with a weighted average remaining term of approximately nine years.

In addition, as of September 30, 2013, we had minimum volume commitments in lean natural gas developments of 1.6 Bcf/d with weighted average remaining terms of over nine years. We also have an emerging crude oil gathering business in the Bakken shale formation with similar minimum volume commitment contract structures. Under our minimum volume commitment contracts, our customers commit to ship a minimum annual volume of natural gas or crude oil on our gathering system, or, in lieu of shipping such volumes, to pay us periodically as if that minimum amount had been shipped.

We generate revenue in our transportation and storage business segment primarily by charging demand fees subject to any applicable tariffs for the transportation and storage of natural gas on our system. We generate our transportation and storage gross margin under long-term, fee-based agreements with a weighted average remaining contract life of over four years as of September 30, 2013. We generally do not take ownership of the natural gas that we transport and store.

The following table shows, on a pro forma basis, the components of our gross margin for the year ended December 31, 2012 and the nine months ended September 30, 2013.

	Fee-Based			
	Demand/ Commitment/ Guaranteed Return	Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2012				
Gathering and Processing Segment	22%	34%	44%	100%
Transportation and Storage Segment	86%	12%	2%	100%
Partnership Weighted Average	51%	23%	26%	100%
Nine Months Ended September 30, 2013				
Gathering and Processing Segment	23%	37%	40%	100%
Transportation and Storage Segment	87%	11%	2%	100%
Partnership Weighted Average	51%	25%	24%	100%

How We Evaluate Our Operations

We use 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 are significant factors in assessing our operating results and profitability and include: (i) throughput volumes; (ii) gross margin; (iii) operation and maintenance expenses; and (iv) Adjusted EBITDA and distributable cash flow.

Throughput Volumes

The volume of natural gas that we gather, process, transport and store depends significantly on the level of production from natural gas wells connected to our systems. Aggregate production volumes are impacted by the overall amount of drilling and completion activity, as production must be maintained or increased by new drilling or other activity, because the production rate of a natural gas well declines over time. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of natural gas and NGLs, the cost to drill and operate a well, the availability and cost of capital and environmental and government regulations. We generally expect the level of drilling to positively correlate with long-term trends in commodity prices. Similarly, production levels nationally and regionally generally tend to positively correlate with drilling activity.

To maintain and increase gathering throughput volumes on our systems, we must continue to contract our capacity to shippers, including producers and marketers. Our transportation and storage systems compete for customers based on the type of service a customer needs, operating flexibility, receipt and delivery points and geographic flexibility and available capacity and price. We actively monitor customer activity in the areas served by our systems to pursue new supply opportunities. To maintain and increase our transportation and storage volumes, we must continue to contract our capacity to shippers, including producers, marketers, LDCs, power generators and end-users.

Gross Margin

We view gross margin as an important performance measure of the core profitability of our business, as well as our operating performance as compared to that of other companies in our industry, without regard to financing methods, historical cost basis, capital structure or the impact of fluctuating commodity prices. We define gross margin as total revenues minus costs of goods sold, excluding depreciation and amortization. Gross margin allows us to make a meaningful comparison of the operating results between our fee-based contacts, which do not involve the purchase or sale of natural gas and/or crude oil, and our commodity-based contracts, which do. In addition, gross margin allows us to make a meaningful comparison of the results of our commodity-based activities across different commodity price environments because it measures the spread between the product sales price and cost of products sold. Please read “Selected Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures.”

Operation and Maintenance Expenses

We seek to maximize the profitability of our operations by effectively managing operation and maintenance expenses. These expenses are comprised primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses. These expenses generally remain relatively stable across broad ranges of throughput volumes but can fluctuate from period to period depending on the mix of activities performed during that period and the timing of these expenses. We will seek to manage our maintenance expenditures on our assets by scheduling maintenance over time to avoid significant variability in our maintenance expenditures and minimize their impact on our cash flow.

The current high levels of crude oil exploration, development and production activities are increasing competition for personnel and equipment. This increased competition is placing upward pressure on the prices we pay for labor, supplies and miscellaneous equipment. To the extent we are unable to procure necessary services or offset higher costs, our operating results will be negatively impacted.

Adjusted EBITDA and Distributable Cash Flow

We define Adjusted EBITDA as net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results. Distributable cash flow will not reflect changes in working capital balances. Please read “Selected Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures.”

Note About Non-GAAP Financial Measures

Gross 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.

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

Management compensates for the limitations of gross margin, Adjusted EBITDA and distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between gross margin, Adjusted EBITDA and distributable cash flow, on the one hand, and revenue, net income and net cash provided by operating activities, on the other hand, and incorporating this knowledge into its decision-making processes. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. For a reconciliation of gross margin, Adjusted EBITDA and distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read “Selected Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures.”

Items Affecting the Comparability of Our Financial Results

Our future results of operations may not be comparable to our historical results of operations for the reasons described below.

Formation of Partnership. For accounting purposes, we treat the formation of our partnership on May 1, 2013 as an acquisition, with the partnership as the acquirer of Enogex. As a result, our historical results of operations for periods prior to May 1, 2013 do not include the results of operations of Enogex.

Operation and Maintenance Expenses. We have entered into services agreements with each of OGE Energy and CenterPoint Energy pursuant to which they perform certain administrative services for us that are generally consistent with the level and type of services they provided to each of their respective businesses prior to our formation. These services include accounting, finance, legal, risk management, information technology and human resources. We are required to reimburse OGE Energy and CenterPoint Energy for their direct expenses or, where the direct expenses cannot reasonably be determined, an allocated cost as set forth in the agreements. Our reimbursement obligations are capped at amounts set forth in our annual budget. The initial term of the services agreements ends in May 2016, after which date they continue on a year-to-year basis unless terminated by us upon 90 days' notice.

Historically, our general and administrative expenses included direct monthly charges for the management and operation of our logistics assets and certain expenses allocated by our sponsors for general corporate services, such as treasury, accounting and legal services. These expenses were charged or allocated to us based on conventions accepted by the regulators of OGE Energy's and CenterPoint Energy's regulated utility assets. For additional information, please see Note 10 to the Unaudited Condensed Combined and Consolidated Financial Statements for the nine months ended September 30, 2013 and 2012.

We also expect to incur approximately $3 million of incremental annual operation and maintenance expense as a result of being a publicly traded partnership.

Income Tax Expenses. Prior to our formation, our assets were included in CenterPoint Energy's consolidated federal income tax returns, which were taxed at the entity level as a C corporation. Following our formation, we are treated as a partnership for federal income tax purposes, with each partner being separately taxed on its share of taxable income; therefore, there is no income tax expense in our financial statements subsequent to May 1, 2013 (other than Texas state margin taxes). As a result of the conversion to a limited partnership, we recorded a one-time income tax benefit of $1.24 billion in the nine months ended September 30, 2013.

Financing. Upon our formation, we entered into our $1.05 billion three-year term loan facility, the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. In addition, upon our formation, we entered into a $1.4 billion five-year revolving credit facility. Initial advances under the revolving credit facility were used for general partnership purposes and to refinance the Enogex revolving credit facility, which was terminated in connection with our formation, and existing indebtedness owing by Enogex to OGE Energy as of May 1, 2013. Please read "—Liquidity and Capital Resources."

Cash Distributions. Following the closing of this offering, we intend to make cash distributions to our unitholders at an initial distribution rate of $ per unit per quarter ($ per unit on an annualized basis). Our partnership agreement requires that we distribute to our unitholders quarterly all of our available cash. As a result, we expect to fund future capital expenditures primarily from external sources, including borrowings under our revolving credit facility and future issuances of equity and debt securities.

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.

Natural Gas Supply and Demand Dynamics

Natural gas continues to be a critical component of energy supply and demand in the United States. Over the long term, we believe that the prospects for continued natural gas demand are favorable and will be driven by population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation due to the low prices of natural gas and stricter government environmental regulations on the mining and burning of coal. According to the EIA, demand for natural gas in the electric power sector is projected to increase from approximately 7.6 Tcf in 2011 to approximately 9.5 Tcf in 2040, with a portion of the growth attributable to the retirement of 49 gigawatts of coal-fired capacity by 2022. The EIA also projects that natural gas consumption in the industrial sector will be higher due to the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slow price growth, particularly from 2011 through 2019, when the price of natural gas is expected to remain below 2010 levels. However, the EIA expects growth in natural gas consumption for power generation and in the industrial sector to be partially offset by decreased usage in the residential sector related primarily to decreased demand for natural gas supplied home heating. We believe that increasing consumption of natural gas will continue to drive natural gas drilling and production over the long term throughout the United States.

Growth in Production of U.S. Shale Plays

Over the past several years, there has been a fundamental shift in U.S. natural gas production towards unconventional resources, which according to the EIA include natural gas produced from shale formations, tight gas and coal beds. The emergence of unconventional natural gas plays and advancements in technology have been crucial factors that have allowed producers to efficiently extract significant volumes of natural gas from these plays, and, more recently, crude oil from shale formation plays. According to the EIA, the dual application of horizontal drilling and hydraulic fracturing has been the primary driver of increases in shale gas production. The development of these unconventional sources has offset declines in other, more traditional U.S. natural gas supply sources, which has helped meet growing consumption and lowered the need for imported natural gas. In fact, the EIA predicts that the U.S. will become a net exporter of natural gas starting in 2020.

Growth in the Williston Basin

In the Williston basin, the Bakken Formation is located across the Northern Great Plains in Montana and North Dakota up into Canada. According to the EIA, the Bakken region now accounts for a little over 10% of total U.S. oil production and is expected to be the fourth region (along with the Gulf of Mexico, Eagle Ford basin and Permian basin) producing more than 1,000 MBbl/d in the nation in December 2013. The growth of crude oil production in the Bakken region is part of a longer-term trend in drilling efficiency gains and has led North Dakota to rank second in crude oil production in the United States, behind only Texas.

Interest Rates

Interest rates have been volatile in recent periods. If interest rates rise, our future financing costs under our revolving credit facility and any other debt instruments will increase accordingly. In addition, because our common units are yield-based securities, rising market interest rates could impact the relative attractiveness of our common units to investors, which could limit our ability to raise funds, or increase the price of raising funds, in the capital markets and may limit our ability to expand our operations or make future acquisitions.

Regulatory Compliance

The regulation of gathering and transmission pipelines, storage and related facilities by FERC and other federal and state regulatory agencies, including the DOT, has a significant impact on our business. For example, the DOT's Pipeline and Hazardous Materials Safety Administration, or PHMSA, has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase our compliance costs and increase the time it takes to obtain required permits. Additionally, increased regulation of oil and natural gas producers, including regulation associated with hydraulic fracturing, could reduce regional supply of oil and natural gas and therefore throughput on our gathering systems. For more information see "Business—Rate and Other Regulation."

Results of Operations—Pro Forma

The discussion of the results of operations presented below covers our pro forma results of operations. These pro forma results may not be indicative of future results or of actual historical results had the transactions described therein occurred as of the dates indicated or the results of operations that might be achieved for any future periods. Please read "Unaudited Pro Forma Condensed Combined Financial Statements."

The following table provides a summary of our results of operations on a pro forma basis for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, and for the year ended December 31, 2012.

Pro forma Nine Months Ended September 30, 2013	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$ 1,605	$ 1,082	$ (391)	$ 2,296
Cost of goods sold (excluding depreciation and amortization)	1,045	656	(389)	1,312
Gross margin on revenues	560	426	(2)	984
Operation and maintenance	202	166	(2)	366
Depreciation and amortization	126	79	—	205
Impairment	12	—	—	12
Taxes other than income	17	28	—	45
Operating income	$ 203	$ 153	$ —	$ 356
Equity in earnings of equity method affiliates	$ —	$ 9	$ —	$ 9

Pro forma Nine Months Ended September 30, 2012	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
	(In millions)			
Revenues	$ 1,242	$ 841	$ (217)	$ 1,866
Cost of goods sold (excluding depreciation and amortization)	709	388	(215)	882
Gross margin on revenues	533	453	(2)	984
Operation and maintenance	173	152	(2)	323
Depreciation and amortization	126	72	—	198
Gain on insurance proceeds	(8)	—	—	(8)
Taxes other than income	14	32	—	46
Operating income	$ 228	$ 197	$ —	$ 425
Equity in earnings of equity method affiliates	$ 5	$ 10	$ —	$ 15

Pro forma Year Ended December 31, 2012	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
		(in millions)		
Revenues	$ 1,728	$ 1,141	$ (305)	$ 2,564
Cost of goods sold (excluding depreciation and amortization)	991	550	(303)	1,238
Gross margin on revenues	737	591	(2)	1,326
Operation and maintenance	240	208	(2)	446
Depreciation and amortization	182	91	—	273
Gain on insurance proceeds	(8)	—	—	(8)
Taxes other than income	18	39	—	57
Operating income	$ 305	$ 253	$ —	$ 558
Equity in earnings of equity method affiliates	$ 5	$ 13	$ —	$ 18

Gathering and Processing

Our gathering and processing business segment reported pro forma operating income of $203 million in the nine months ended September 30, 2013 compared to $228 million in the nine months ended September 30, 2012. Pro forma operating income declined $25 million primarily due to an increase in operation and maintenance expenses of $29 million, an impairment of $12 million in the nine months ended September 30, 2013, and a $8 million gain on insurance proceeds recognized in the nine months ended September 30, 2012, partially offset by an increase in pro forma gross margin of $27 million. Our gathering and processing business segment reported pro forma operating income of $305 million in the year ended December 31, 2012.

Pro forma gross margin increased $27 million from the nine months ended September 30, 2012 to the nine months ended September 30, 2013 primarily due to the acquisition of Waskom and other acquisitions of $24 million and $9 million, respectively, higher gathering and processing fixed-fee volumes of $68 million, higher natural gas prices of $17 million and increased processing margins of $4 million, partially offset by a decline in customer volumes of $15 million and a decline in NGL price spreads between Conway and Mont Belvieu, along with the conversion of a processing contract from keep-whole to fixed-fee resulting in an $80 million decline. Our pro forma gross margin was $737 million in the year ended December 31, 2012.

Pro forma operation and maintenance expenses increased $29 million from the nine months ended September 30, 2012 to the nine months ended September 30, 2013 primarily due to an increase in general and administrative expenses related to an increase in payroll related expense of $18 million to support business growth, partially due to growth from other acquisitions and an increased headcount, $3 million in contract and service expenses, higher non-capital costs of $2 million, integration costs of $2 million, increased rental expense of $1 million due to additional leased compression, and an increase in amounts charged from affiliates of $1 million. Our pro forma operation and maintenance expense was $240 million in the year ended December 31, 2012.

The impairment charge of $12 million was a result of an impairment loss during the nine months ended September 30, 2013 on the assets of the Service Star business line, a component of the gathering and processing business segment that provides measurement and communication services to third parties. Upon formation as a private limited partnership on May 1, 2013, management of the partnership reassessed the long-term strategy related to Service Star. Based on forecasted future undiscounted cash flows, management determined that the carrying value of the Service Star assets were not fully recoverable. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the nine months ended September 30, 2013, the partnership recognized a $12 million impairment charge, consisting of a

$10 million write-down of property, plant and equipment and a $2 million write-down of materials and supplies inventory considered either excess or obsolete. We did not have any material impairment charges in the year ended December 31, 2012.

Pro forma gain on insurance proceeds related to the reimbursement costs incurred to replace the damaged train at the Cox City natural gas processed plant of $8 million in the nine months ended September 30, 2012. Our pro forma gain on insurance proceeds was $8 million in the year ended December 31, 2012.

Pro forma Equity Earnings. Our gathering and processing business segment recorded pro forma equity income of $5 million for the nine months ended September 30, 2012 from its 50% interest in Waskom. This amount is included in equity in earnings of equity method affiliates under the Other Income (Expense) caption in the Unaudited Pro Forma Statements of Condensed Combined and Consolidated Income. Beginning on August 1, 2012, financial results for Waskom are consolidated (combined) and included in pro forma operating income. Our pro forma equity in earnings was $5 million in the year ended December 31, 2012.

Transportation and Storage

Our transportation and storage business segment reported pro forma operating income of $153 million in the nine months ended September 30, 2013 compared to $197 million in the nine months ended September 30, 2012. Pro forma operating income decreased $44 million resulting primarily from a decline in gross margin of $27 million, an increase of $14 million in operation and maintenance expenses, and an increase of $7 million in depreciation and amortization. These decreases to operating income were partially offset by a decline of $4 million in taxes other than income taxes. Our transportation and storage business segment reported pro forma operating income of $253 million in the year ended December 31, 2012.

On a pro forma basis, gross margin decreased $27 million from the nine months ended September 30, 2012 to the nine months ended September 30, 2013 primarily due to a decline in gross margins attributable to lower volumes, primarily due to lower price differentials, which negatively impacted margins on ancillary services through a $7 million reduction in balancing services, a $5 million reduction in liquid sales, a $7 million reduction to margins on off-system transportation revenues, a $4 million decline in interruptible transportation fees, and a $5 million reduction to storage demand fees. Additionally, gross margin included a storage gas loss of $3 million in the nine months ended September 30, 2013. These decreases were partially offset by continued improvements to gross margin of $7 million due to the impact of the 10-year agreements, entered into in 2010, with natural gas distribution affiliates of CenterPoint Energy.

On a pro forma basis, operation and maintenance expenses increased $14 million from the nine months ended September 30, 2012 to the nine months ended September 30, 2013 primarily due to integration costs of $6 million, a litigation settlement reserve of $5 million, and an increase in corporate service costs provided by affiliates of $2 million. Our pro forma operation and maintenance expense was $208 million in the year ended December 31, 2012.

Pro forma depreciation and amortization increased $7 million due to additional assets in-service of $4 million and the implementation of MRT’s rate case settlement of $3 million during the nine months ended September 30, 2013. Our pro forma depreciation and amortization expense was $182 million in the year ended December 31, 2012.

Pro forma Equity Earnings. Our transportation and storage business segment reported pro forma equity income of $9 million and $10 million for the nine months ended September 30, 2013 and 2012, respectively, from our pro forma 24.95% interest in SESH. These amounts are included in equity in earnings of equity method affiliates under the Other Income (Expense) caption in the Unaudited Pro Forma Statements of Condensed Combined and Consolidated Income. Our pro forma equity in earnings was $13 million in the year ended December 31, 2012.

Combined and Consolidated Pro Forma Information

	Pro forma		
	Year ended December 31,	Nine Months Ended September 30,	
	2012	2013	2012
	(In millions)		
Operating Income	$ 558	$ 356	$ 425
Other Income (Expense):			
Interest expense	(45)	(35)	(33)
Equity in earnings of equity method affiliates	18	9	15
Step acquisition gain	136	—	136
Other, net	(4)	9	—
Total Other Income (Expense)	105	(17)	118
Income Before Income Taxes	663	339	543
Income tax expense	3	1	2
Net Income	$ 660	$ 338	$ 541
Less: Net income attributable to noncontrolling interest	2	2	2
Net Income attributable to Enable Midstream Partners, LP	$ 658	$ 336	$ 539

We reported pro forma net income of $338 million and $541 million in the nine months ended September 30, 2013 and 2012, respectively. The decrease in pro forma net income of $203 million was primarily attributable to a decline in pro forma operating income (discussed by segment above) of $69 million, the pro forma step acquisition gain incurred in the nine months ended September 30, 2012 on the acquisition of the previously outstanding 50% interest in Waskom of $136 million, and a decline in equity in earnings of equity method affiliates of $6 million attributable to the acquisition and consolidation (combination) of Waskom in August 2012. These decreases were partially offset by a pre-tax gain of $10 million, included in the Other, net caption in the Unaudited Pro Forma Statements of Condensed Combined and Consolidated Income, recognized in the nine months ended September 30, 2013 related to the sale of gathering assets on the Texas portion of Enogex's system. Pro forma net income was $660 million in the year ended December 31, 2012.

Historical Results of Operations—Interim Periods

The historical financial information included below reflects the assets, liabilities and operations of the entities comprising CenterPoint Energy's interstate pipelines and field services reportable business segments for periods ending prior to May 1, 2013 and the consolidated assets, liabilities and operations of these entities and Enogex for periods ending on or after May 1, 2013. With respect to these historical periods, we refer to CenterPoint Energy's Interstate Pipelines segment as our Transportation and Storage segment and CenterPoint Energy's Field Services segment as our Gathering and Processing segment.

Nine Months Ended September 30, 2013 compared to Nine Months Ended September 30, 2012

Historical Nine Months Ended September 30, 2013	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
		(In millions)		
Revenues	$ 1,135	$ 784	$ (254)	$ 1,665
Cost of goods sold (excluding depreciation and amortization)	673	406	(252)	827
Gross margin on revenues	462	378	(2)	838
Operation and maintenance	155	149	(2)	302
Depreciation and amortization	80	68	—	148
Impairment	12	—	—	12
Taxes other than income	13	24	—	37
Operating income	$ 202	$ 137	$ —	$ 339
Equity in earnings of equity method affiliates	—	$ 12	$ —	$ 12

Historical Nine Months Ended September 30, 2012	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
		(In millions)		
Revenues	$ 350	$ 374	$ (38)	$ 686
Cost of goods sold (excluding depreciation and amortization)	76	35	(36)	75
Gross margin on revenues	274	339	(2)	611
Operation and maintenance	82	111	(2)	191
Depreciation and amortization	35	43	—	78
Taxes other than income	4	24	—	28
Operating income	$ 153	$ 161	$ —	$ 314
Equity in earnings of equity method affiliates	$ 5	$ 20	$ —	$ 25

Gathering and Processing

Our gathering and processing business segment reported operating income of $202 million in the nine months ended September 30, 2013 compared to $153 million in the nine months ended September 30, 2012. Operating income increased $49 million primarily from increased margins of $188 million partially offset by an increase in operation and maintenance expenses of $73 million, an increase in depreciation and amortization of $45 million, an increase in taxes other than income of $9 million, and an impairment charge of $12 million discussed above, during the nine months ended September 30, 2013.

Gross margin increased $188 million primarily due to the acquisition of Enogex, Waskom and other acquisitions of $148 million, $24 million and $9 million, respectively, higher natural gas prices of $17 million and increased processing margins of $4 million, partially offset by a decline in customer volumes of $15 million.

Operation and maintenance expenses increased $73 million primarily due to the acquisition of Enogex, which contributed $57 million of operation and maintenance expenses, and an increase in general and administrative expenses related to an increase payroll related expense of $11 million to support business growth, partially due to growth from other acquisitions, $3 million in contract and service expenses and integration costs of $2 million.

Depreciation and amortization increased $45 million due to the additional assets placed in-service from the acquisition of Enogex and other additions of $34 million and $11 million, respectively, in the nine months ended September 30, 2013.

Taxes other than income increased $9 million due to increased ad valorem taxes as a result of additional assets placed in service from the acquisition of Enogex and other additions of $4 million and $3 million, respectively, as well as an increase in sales and use taxes in the business of $2 million.

The gathering and processing business segment recorded equity in earnings of equity method affiliates of $5 million for the nine months ended September 30, 2012 from its 50% interest in Waskom. These amounts are included in equity in earnings of equity method affiliates under the Other Income (Expense) caption in the Condensed Combined and Consolidated Statements of Income. Beginning on August 1, 2012, the financial results for Waskom are consolidated (combined) and included in operating income.

Transportation and Storage

Our transportation and storage business segment reported operating income of $137 million in the nine months ended September 30, 2013 compared to $161 million in the nine months ended 2012. Operating income decreased $24 million primarily resulting from an increase of $38 million in operation and maintenance expenses as well as $25 million in depreciation and amortization. These decreases to operating income were partially offset by an increase in gross margin of $39 million.

Gross margin increased $39 million primarily due to the acquisition of Enogex which contributed $56 million to gross margin, offset by a decline in gross margins attributable to lower volumes, primarily due to lower price differentials, which negatively impacted margins on ancillary services through a $7 million reduction in balancing services, a $5 million reduction in liquid sales, and a reduction to margins on off-system transportation revenues of $7 million. Additionally, gross margin included a storage gas loss reserve of $3 million in the nine months ended September 30, 2013. These decreases were partially offset by continued improvements to gross margin of $7 million due to the impact of the 10-year agreements, entered into in 2010, with natural gas distribution affiliates of CenterPoint Energy.

Operation and maintenance expenses increased $38 million primarily due to the acquisition of Enogex which contributed $22 million to operation and maintenance expenses and integration costs of $6 million, a litigation settlement reserve of $5 million, and an increase in corporate service costs provided by affiliates of $2 million recognized in the nine months ended September 30, 2013.

Depreciation and amortization increased $25 million primarily due to the additional assets in-service from the acquisition of Enogex of $21 million and asset additions of $2 million and the implementation of MRT’s rate case settlement of $3 million during the nine months ended September 30, 2013.

The transportation and storage business segment recorded equity in earnings of equity method affiliates of $12 million and $20 million for the nine months ended September 30, 2013 and 2012, respectively, from its interest in SESH, a jointly owned pipeline. The $8 million decline in equity in earnings of equity method affiliates in the nine months ended September 30, 2013 was attributable to the reduction to our 50% historical interest in SESH on May 1, 2013, when the partnership distributed a 24.95% interest in SESH to CenterPoint Energy, of $5 million and an increase in expenditures associated with unplanned pipeline maintenance.

Combined and Consolidated Interim Information

	Historical Nine Months Ended September 30, 2013	2012
	(In millions)	
Operating Income	$ 339	$ 314
Other Income (Expense):		
Interest expense	(53)	(65)
Equity in earnings of equity method affiliates	12	25
Interest income—affiliated companies	9	15
Step acquisition gain	—	136
Other, net	—	1
Total Other Income (Expense)	(32)	112
Income Before Income Taxes	307	426
Income tax expense (benefit)	(1,195)	160
Net Income	$ 1,502	$ 266
Less: Net income attributable to noncontrolling	2	—
Net Income attributable to Enable Midstream Partners, LP	$ 1,500	$ 266

Net Income. We reported net income of $1.5 billion and $266 million in the nine months ended September 30, 2013 and 2012, respectively. The increase in net income of $1.23 billion was primarily attributable to a positive impact from income taxes of $1.36 billion, the acquisition of Enogex on May 1, 2013 of $54 million, and a decrease in interest expense of $20 million (excluding the impact of interest on debt acquired with Enogex) offset by a decrease in operating income of $38 million (excluding the impact of the acquisition of Enogex and discussed by business segment above) and a decrease in equity earnings in equity method affiliates of $13 million (discussed by business segment above), and a decrease in interest income of $6 million as a result of the a reduction in notes receivable in the nine months ended September 30, 2013. Additionally, we recorded a step acquisition gain of $136 million in the nine months ended September 30, 2012 attributed to the acquisition of the outstanding 50% interest in Waskom in August 2012.

Interest Expense. Interest expense decreased $12 million primarily due to lower interest rates on the term loan facility and revolving credit facility, which were entered into May 1, 2013, and a reduction in borrowings of $20 million (excluding the impact of debt acquired with Enogex), offset by an increase in interest expense incurred on the debt assumed with the acquisition of Enogex of $8 million.

Income Tax Expense. Effective May 1, 2013, upon conversion to a limited partnership, the partnership's earnings are no longer subject to income taxes (other Texas state margin taxes). As a result of the conversion to a partnership, we derecognized our outstanding current income tax liabilities and deferred income tax asset and liabilities by recording a provision for income tax benefit equal to $1.24 billion. Consequently, the Condensed Combined and Consolidated Statement of Income for the nine months ended September 30, 2013 does not include an income tax provision for income earned on or after May 1, 2013 (other than Texas state margin taxes).

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Historical Results of Operations—Annual Periods

Historical Year Ended December 31, 2012	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
		(In millions)		
Revenues	$ 502	$ 502	$ (52)	$ 952
Cost of goods sold (excluding depreciation and amortization)	124	55	(50)	129
Gross margin on revenues	378	447	(2)	823
Operation and maintenance	114	155	(2)	267
Depreciation and amortization	50	56	—	106
Taxes other than income	5	29	—	34
Operating income	$ 209	$ 207	$ —	$ 416
Equity in earnings of equity method affiliates	$ 5	$ 26	$ —	$ 31

Historical Year Ended December 31, 2011	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
		(In millions)		
Revenues	$ 415	$ 553	$ (36)	$ 932
Cost of goods sold (excluding depreciation and amortization)	70	65	(34)	101
Gross margin on revenues	345	488	(2)	831
Operation and maintenance	111	154	(2)	263
Depreciation and amortization	37	54	—	91
Taxes other than income	5	32	—	37
Operating income	$ 192	$ 248	$ —	$ 440
Equity in earnings of equity method affiliates	$ 10	$ 21	$ —	$ 31

Historical Year Ended December 31, 2010	Gathering and Processing	Transportation and Storage	Eliminations	Enable Midstream Partners, LP
		(In millions)		
Revenues	$ 340	$ 601	$ (70)	$ 871
Cost of goods sold (excluding depreciation and amortization)	75	91	(68)	98
Gross margin on revenues	265	510	(2)	773
Operation and maintenance	80	155	(2)	233
Depreciation and amortization	25	52	—	77
Taxes other than income	4	33	—	37
Operating income	$ 156	$ 270	$ —	$ 426
Equity in earnings of equity method affiliates	$ 10	$ 19	$ —	$ 29

Gathering and Processing

2012 Compared to 2011. Our gathering and processing business segment reported operating income of $209 million for 2012 compared to $192 million for 2011. Operating income increased $17 million primarily from increased margins of $33 million due to gathering projects in the Haynesville shale, including revenues from throughput guarantees, growth in gathering services and retained natural gas volumes of $36 million, and acquisitions completed in 2012 of $34 million, partially offset by lower commodity prices of $28 million on sales of retained natural gas and a decline in processing revenues of $2 million and other contract revenue of $4 million. Operating income also increased $3 million due to the acquisition of the outstanding 50% interest in Waskom on July 31, 2012, which resulted in our consolidation (combination) of our 100% interest in Waskom, higher operation and maintenance expenses of $3 million and increased depreciation expense of $13 million attributable to additional in-service assets. Prior to August 2012, our 50% interest in Waskom was reported under equity in earnings of equity method affiliates.

2011 Compared to 2010. Our gathering and processing business segment reported operating income of $192 million for 2011 compared to $156 million for 2010. Operating income increased $36 million primarily from increased margins of $80 million due primarily to gathering projects in the Haynesville and Fayetteville shales and growth in core gathering services, including revenues from throughput guarantees of $88 million, partially offset by lower commodity prices of $10 million from sales of retained natural gas and reduced processing margins. Increases in operation and maintenance expenses of $31 million (discussed below), depreciation expense of $12 million due to an increase in assets in-service and taxes other than income of $1 million resulted primarily from the expansion of the Magnolia and Olympia gathering systems in North Louisiana. The increase in operation and maintenance in 2011 was the result of a 2010 benefit from a gain on the sale of non-strategic gathering assets by $21 million and an increase in payroll related expenses in 2011 of $7 million.

Equity Earnings. Our gathering and processing business segment recorded equity income of $5 million, $10 million and $10 million for the years ended December 31, 2012, 2011 and 2010, respectively, from its 50% interest in Waskom. These amounts are included in equity in earnings of equity method affiliates under the Other Income (Expense) caption in the Statements of Combined and Consolidated Income. Beginning on August 1, 2012, financial results for Waskom are consolidated (combined) and included in operating income.

Transportation and Storage

2012 Compared to 2011. Our transportation and storage business segment reported operating income of $207 million for 2012 compared to $248 million for 2011. Operating income decreased $41 million primarily due to lower margins resulting from a backhaul contract that expired in 2011 for $16 million, a reduction in compressor efficiency of $8 million on the Carthage to Perryville pipeline due to lower volumes, lower off-system transportation revenues of $8 million, lower seasonal and market-sensitive transportation contracts of $7 million and a decline in margin on ancillary services of $7 million. The margin declines were partially offset by the effects of the 10-year agreements with natural gas distribution affiliates of CenterPoint Energy, which we restructured in 2010 and increased gross margin by $5 million in 2012. In addition to the lower margins, operating income decreased due to higher operation and maintenance expenses of $1 million and higher depreciation and amortization expenses of $2 million due to additional in-service assets, offset by lower taxes other than income taxes of $3 million primarily related to a decline in sales and use taxes.

2011 Compared to 2010. Our transportation and storage business segment reported operating income of $248 million for 2011 compared to $270 million for 2010. Operating income decreased $22 million primarily due to a $22 million decline in gross margin due to a backhaul contract that expired in 2011 and lower system revenues of $11 million, as well as to increased depreciation and amortization expenses of $2 million related to additional in-service assets. The effects of the restructured 10-year agreements with natural gas distribution affiliates of CenterPoint Energy, which we restructured in 2010, resulted in a decrease to gross margin of $11 million in 2011. The gross margin decreases were offset by new firm transportation contracts and higher ancillary revenues increasing gross margin by $22 million in 2011. The decline in operating income was partially offset by lower operation and maintenance expenses of $1 million and lower taxes other than income of $1 million.

Equity Earnings. Our transportation and storage business segment recorded equity in earnings of equity method affiliates of $26 million, $21 million and $19 million for the years ended December 31, 2012, 2011 and 2010, respectively, from our 50% interest in SESH. The 2012 increase in equity earnings primarily resulted from restructuring and extending a long-term agreement with an anchor shipper at the end of 2011.

These amounts are included in equity in earnings of equity method affiliates under the Other Income (Expense) caption in the Combined Statements of Income for the years ended December 31, 2012, 2011 and 2010 and for the nine months ended September 30, 2012 and in the Condensed Combined and Consolidated Statement of Income for the nine months ended September 30, 2013.

Combined Annual Historical Information

	Historical Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Operating Income	$ 416	$ 440	$ 426
Other Income (Expense):			
Interest expense—affiliated companies	(85)	(90)	(83)
Equity in earnings of equity method affiliates	31	31	29
Interest income—affiliated companies	21	14	9
Step acquisition gain	136	—	—
Other, net	—	—	(2)
Total	103	(45)	(47)
Income Before Income Taxes	519	395	379
Income tax expense	203	163	155
Net Income Attributable to Enable Midstream Partners, LP	$ 316	$ 232	$ 224

2012 Compared to 2011.

Net Income. We reported net income of $316 million for 2012 compared to $232 million for the same period in 2011. The increase in net income of $84 million was primarily due to a $136 million step acquisition gain related to the acquisition of an additional 50% interest in Waskom, a $5 million decrease in interest expense due to lower levels of debt and a $7 million increase in interest income due to an increase in notes receivable—affiliated companies in 2012. These increases were partially offset by a $24 million decline in operating income (discussed by business segment above) and an increase of $40 million in income tax expense.

Income Tax Expense. We reported an effective tax rate of 39.1% for 2012 compared to 41.3% for the same period in 2011. The decrease in the effective tax rate of 2.2% was due primarily to a $3 million reduction in state income taxes on an increase of $124 million in income before income taxes.

2011 Compared to 2010.

Net Income. We reported net income of $232 million for 2011 compared to $224 million for the same period in 2010. The increase in net income of $8 million was primarily due to a $14 million increase in operating income (discussed by business segment above) and a $5 million increase in interest income due to increased outstanding notes receivable—affiliated companies, which were partially offset by a $7 million increase in interest expense due to higher levels of debt and a $8 million increase in income tax expense.

Income Tax Expense. We reported an effective tax rate of 41.3% for 2011 compared to 40.9% for the same period in 2010. The increase in the effective tax rate of 0.4% was due to a $6 million increase in income taxes in

2011, which was partially offset by a $4 million expense recorded in 2010 to reflect a tax law change impacting the deductibility of retiree health care costs.

Liquidity and Capital Resources

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

- cash generated from operations;
- retained proceeds of this offering;
- borrowings under our revolving 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 meet our requirements for working capital and capital expenditures for the foreseeable future.

Capital Requirements

The midstream business is capital intensive and can require significant investment to maintain and upgrade existing operations, connect new wells to the system, organically grow into new areas and comply with environmental and safety regulations. Going forward, our capital requirements will consist of the following:

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

As more completely discussed in “Cash Distribution Policy and Restrictions on Distributions—Significant Forecast Assumptions—Capital Expenditures,” for the twelve months ending December 31, 2014, we estimate that our maintenance and expansion capital expenditures will total approximately $647 million. Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, borrowings under our revolving credit facility or new debt offerings or the issuance of additional partnership units.

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 (an aggregate distribution of $ million per quarter, or $ million on an annualized basis, if the underwriters exercise their option to purchase additional common units). We do not have a legal obligation to make distributions except as provided in our partnership agreement.

In determining the amount of distributable cash flow, the board of directors of our general partner will determine the amount of cash reserves to set aside for our operations, including reserves for future working capital, maintenance capital expenditures, expansion capital expenditures, acquisitions and other matters, which will impact the amount of cash we are able to distribute to our unitholders. However, we expect that we will rely primarily upon external financing sources, including borrowings under our revolving credit facility and issuances of debt and equity securities, as well as cash reserves, to fund our expansion capital expenditures including acquisitions. To the extent we are unable to finance growth externally and are unwilling to establish cash reserves to fund future expansions, our distributable cash flow will not significantly increase. 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 expansion capital expenditures including acquisitions, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or in the terms of our revolving credit facility on our ability to issue additional units, including units ranking senior to the common units.

Revolving Credit Facility

On May 1, 2013, we entered into a $1.4 billion, five-year senior unsecured revolving credit facility (revolving credit facility). As of September 30, 2013, there was $142 million in principal advances and $1 million in letters of credit outstanding under the revolving credit facility. As of November 30, 2013, there was $325 million in principal advances and $1 million in letters of credit outstanding under the revolving credit facility.

Outstanding borrowings under the revolving credit facility bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at our election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of September 30, 2013, the applicable margin for LIBOR-based borrowings under the revolving credit facility was 1.625% based on our credit ratings. In addition, the revolving credit facility requires us to pay a fee on unused commitments. The commitment fee is based on our applicable credit rating from Moody’s Investors Service, Inc., Standard & Poor’s Ratings Services, a division of The McGraw-Hill Companies, and Fitch, Inc. As of September 30, 2013, the commitment fee under the revolving credit facility was 0.25% per annum based on our credit ratings.

Advances under the revolving credit facility are subject to certain conditions precedent, including the accuracy in all material respects of certain representations and warranties and the absence of any default or event of default. Initial advances under the revolving credit facility were used for general partnership purposes and to refinance the Enogex revolving credit facility, which was terminated in connection with our formation, and existing indebtedness owing by Enogex to OGE Energy as of May 1, 2013.

The revolving credit facility contains a financial covenant requiring us to maintain a ratio of consolidated funded debt to consolidated EBITDA as defined under the revolving credit facility as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for a certain period of time following the consummation by us or certain of our subsidiaries of any one or more related acquisitions with a purchase price of at least $50 million in the aggregate, the consolidated funded debt to consolidated EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The revolving credit facility also contains covenants that restrict us and certain subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the revolving credit facility), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. Borrowings under the revolving credit facility are subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany) of $100 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $100 million, and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Term Loan Facility

On May 1, 2013, we entered into a $1.05 billion three-year senior unsecured term loan facility (term loan facility), the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of our obligations under the term loan facility, which guarantee is subordinated to all senior debt of such wholly owned subsidiary of CenterPoint Energy.

Outstanding borrowings under the term loan facility bear interest at LIBOR and/or an alternate base rate, at our election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of September 30, 2013, the applicable margin for LIBOR-based borrowings under the term loan facility was 1.625% based on our credit ratings.

The term loan facility contains a financial covenant requiring us to maintain a consolidated funded debt to EBITDA ratio as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for a certain period of time following the consummation by us or certain of our subsidiaries of any one or more related acquisitions with a purchase price of at least $50 million in the aggregate, the consolidated funded debt to EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The term loan facility contains covenants that restrict us and certain subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the term loan facility), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. Borrowings under the term loan facility are subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany) of $100 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $100 million, and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Promissory Notes Payable to Sponsors

Certain of the entities contributed to us by CenterPoint Energy on May 1, 2013 were obligated on approximately $363 million of indebtedness owed to a wholly owned subsidiary of CenterPoint Energy. As of September 30, 2013, the $363 million notes payable—affiliated companies bear an annual interest rate of 2.10% to 2.45% and are scheduled to mature in 2017.

Enable Oklahoma Term Loan

Effective May 1, 2013 upon the acquisition of Enogex, our debt includes a $250 million variable rate term loan (Enable Oklahoma term loan).

Outstanding borrowings under the Enable Oklahoma term loan bear interest at LIBOR and/or an alternate base rate, at our election, plus an applicable margin. The applicable margin is based on Enable Oklahoma’s applicable credit ratings. As of September 30, 2013, the applicable margin for LIBOR-based borrowings under the term loan facility was 1.50%.

The Enable Oklahoma term loan contains a financial covenant requiring Enable Oklahoma to maintain a consolidated funded debt to EBITDA ratio as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for a certain period of time following the consummation by Enable Oklahoma or certain of its subsidiaries of any one or more related acquisitions with a purchase price of at least $25 million in the aggregate, the consolidated funded debt to EBITDA ratio as of the last day of each such fiscal quarter during such period is permitted to be up to 5.50 to 1.00.

The Enable Oklahoma term loan contains covenants that restrict Enable Oklahoma and certain of its subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the Enable Oklahoma term loan), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. The Enable Oklahoma term loan is subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany) of $65 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $65 million, and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Enable Oklahoma Senior Notes

Effective May 1, 2013 upon the acquisition of Enogex, our debt includes $200 million of 6.875% senior notes due July 2014 and $250 million of 6.25% senior notes due March 2020 (collectively, the Enable Oklahoma senior notes).

Contractual Obligations

In the ordinary course of business we enter into various contractual obligations for varying terms and amounts. The following table includes our contractual obligations and other commitments as of September 30, 2013 and our best estimate of the period in which the obligation will be settled:

	2013	2014-2015	2016-2017	After 2017	Total
			(In millions)		
Maturities of long-term debt(1)	$—	$ 450	$ 1,050	$ 392	$1,892
Notes payable—affiliated companies(2)	—	—	363	—	363
Noncancellable operating leases	2	10	2	—	14
Other purchase obligations and commitments	3	15	1	—	19
Total contractual obligations	5	475	1,416	392	2,288

(1) Estimated contractual interest payments associated with long-term debt are $7 million, $95 million, $42 million and $40 million in 2013, 2014 through 2015, 2016 through 2017 and after 2017, respectively. The revolving credit facility, term loan facility and Enable Oklahoma term loan estimated contractual interest payments are calculated utilizing the respective variable interest rates as of September 30, 2013.

(2) Estimated contractual interest payments associated with notes payable—affiliated companies are zero, $15 million, $15 million and zero in 2013, 2014 through 2015, 2016 through 2017 and after 2017, respectively.

Customer Concentration

We rely on certain key natural gas producer customers for a significant portion of our natural gas and NGLs supply. For the nine months ended September 30, 2013, on a pro forma basis, our top ten natural gas producer customers accounted for approximately 75% of our gathered volumes. These customers include affiliates of Encana, Shell, Exxon, Chesapeake, Apache, Continental, QEP, Devon, BP and Samson.

We rely on certain key utilities for a significant portion of our transportation and storage demand. For the nine months ended September 30, 2013, on a pro forma basis, our top transportation and storage customers by gross margin were affiliates of CenterPoint Energy, Laclede, Exxon, OGE Energy and AEP.

Our sources of liquidity have historically included cash generated from operations, our equity investments and our contributions by CenterPoint Energy, OGE Energy and ArcLight and borrowings under our revolving credit facility.

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, and the level and timing of spending for maintenance and expansion activity. As of September 30, 2013, we had a working capital deficit of $197 million due primarily to $200 million of the current portion of long-term debt due July 2014, excluding the premiums on senior notes, that we expect to repay in 2014 upon refinancing. We utilize the revolving credit facility to manage the timing of cash flows and fund short-term working capital deficits.

Cash Flows

The following tables reflect cash flows for the applicable periods:

	Nine months ended September 30,	
	2013	2012
	(In millions)	
Net cash provided by operating activities	$ 472	$ 357
Net cash provided by (used in) investing activities	63	(576)
Net cash provided by (used in) financing activities	(511)	221

	Year ended December 31,		
	2012	2011	2010
	(In millions)		
Net cash provided by operating activities	$ 451	$ 662	$ 308
Net cash used in investing activities	(645)	(560)	(800)
Net cash provided by (used in) financing activities	194	(102)	492

Operating Activities

The increase of $115 million, or 32%, in net cash provided by operating activities for the nine months ended September 30, 2013 as compared to the nine months September 30, 2012 was primarily due to:

- the acquisition of Enogex on May 1, 2013, which added $204 million in gross margin and $78 million in operation and maintenance expenses during the nine months ended September 30, 2013; and
- excluding the acquisition of Enogex:
  - higher Gathering and Processing gross margin of $40 million;
  - lower Transportation and Storage gross margin of $17 million;
  - integration costs of $8 million, higher payroll related expenses of $11 million and higher contracts and services expenses of $3 million, all within operation and maintenance expenses; and

- the impact of the timing of payments and receipts on changes in assets and liabilities.

The decrease of $211 million, or 32%, in net cash provided by operating activities for the year ended December 31, 2012 as compared to the year ended December 31, 2011 was primarily due to:

- higher gathering and processing gross margin of $33 million;
- lower transportation and storage gross margin of $41 million;
- higher operation and maintenance expenses of $4 million; and
- the impact of the timing of payments and receipts on changes in assets and liabilities.

The increase of $354 million in net cash provided by operating activities for the year ended December 31, 2011 as compared to the year ended December 31, 2010 was primarily due to:

- higher gathering and processing gross margin of $80 million;
- lower transportation and storage gross margin of $22 million;
- higher operation and maintenance expenses of $30 million, driven by the growth in our gathering and processing segment; and
- the impact of the timing of payments and receipts on changes in assets and liabilities.

Investing Activities

The increase of $639 million in net cash provided by investing activities for the nine months September 30, 2013 as compared to the nine months September 30, 2012 was primarily due to:

- lower gathering and processing capital expenditures of $127 million;
- higher transportation and storage capital expenditures of $16 million; and
- the receipt of $514 million on notes receivable—affiliated companies.

The increase of $85 million, or 15%, in net cash used in investing activities for the year ended December 31, 2012 as compared to the year ended December 31, 2011 was primarily due to:

- higher gathering and processing capital expenditures of $182 million;
- higher transportation and storage capital expenditures of $34 million; and
- the payment of $142 million on notes receivable—affiliated companies.

The decrease of $240 million, or 30%, in net cash used in investing activities for the year ended December 31, 2011 as compared to the year ended December 31, 2010 was primarily due to:

- lower gathering and processing capital expenditures of $373 million;
- lower transportation and storage capital expenditures of $4 million; and
- the receipt of $124 million on notes receivable—affiliated companies.

Financing Activities

The increase of $732 million in net cash used in financing activities for the nine months September 30, 2013 as compared to the nine months September 30, 2012 was primarily due to:

- the net cash used in financing activities of $450 million for the nine months ended September 30, 2013 resulting from the financing transactions associated with our formation and the acquisition of Enogex on May 1, 2013, compared to net cash provided from notes payable—affiliated companies of $221 million for the nine months ended September 30, 2012; and

- the distribution of $61 million to limited partners in the nine months ended September 30, 2013.

The increase of $296 million in net cash provided by financing activities for the year ended December 31, 2012 as compared to the year ended December 31, 2011 was primarily due to:

- the issuance of $363 million in long-term notes payable—affiliated companies; and
- a decrease in short-term notes payable—affiliated companies of $67 million.

The increase of $594 million in net cash used in financing activities for the year ended December 31, 2011 as compared to the year ended December 31, 2010 was primarily due to a decrease in short-term notes payable – affiliated companies of $594 million.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Credit Risk

We are exposed to certain credit risks relating to our ongoing business operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and the partnership could incur losses. 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.

Quantitative and Qualitative Disclosures about Market Risk

We are exposed to various market risks, including volatility in commodity prices and interest rates.

Commodity Price Risk

While we generate a substantial portion of our gross margin pursuant to long-term, fee-based contracts that include minimum volume commitment and/or demand fees, we are also exposed to changes in the prices for natural gas and NGLs at various market hubs. Our commodity-based margin is related to the realization of our natural gas, NGL and condensate commodity positions associated with the operations and contractual terms of our gathering and processing arrangements as well as fuel charges net of the fuel used to operate our system that is not otherwise subject to a fuel tracker system.

Based on our forecasted volumes, prices and contractual arrangements, we estimate approximately $305 million, or 22%, of our total gross margin for the twelve months ending December 31, 2014 is directly exposed to changes in commodity prices. Holding all other assumptions constant, we estimate that (i) a 10% increase or decrease in the price of natural gas from forecasted levels would result in an increase or decrease, respectively, of approximately $20 million in net income for the twelve months ending December 31, 2014 and (ii) a 10% increase or decrease in the price of NGLs from forecasted levels would result in an increase or decrease, respectively, of approximately $7 million in net income for the twelve months ending December 31, 2014.

We have not entered into any material derivative contracts to manage our exposure to commodity price risk for the twelve months ending December 31, 2014 or thereafter.

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness associated with our revolving credit facility and the refinancing of our existing term loans. The credit markets have recently experienced historical lows in interest rates. It is possible that interest rates could continue to rise from these low levels in the future, which would cause our financing costs on floating rate credit facilities and future debt offerings to be higher than current levels. Based upon the balance of revolving credit facility and existing term loans as of September 30, 2013, a hypothetical increase or decrease in interest rates of 1.0% would have increased or decreased annual interest charges under these agreements by $14 million.

Impact of Seasonality

While the results of our gathering and processing segment are not materially affected by seasonality, from time-to-time our operations can be impacted by inclement weather. Our transportation and storage segment experiences seasonal impacts associated with storage spreads, basis spreads on market-based pipelines, power plant demand and local distribution company customer demand.

Critical Accounting Policies and Estimates

Our financial statements and the related notes thereto contain information that is pertinent to Management's Discussion and Analysis. In preparing our financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the partnership's financial statements. However, the partnership believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the partnership that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the partnership where the most significant judgment is exercised for all partnership business segments includes the determination of impairment estimates of long-lived assets (including intangible assets) and goodwill, valuation of revenues, natural gas purchases, valuation of assets, depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets and commitments and contingencies. The selection, application and disclosure of the following critical accounting estimates have been discussed with the partnership's board of directors. The partnership discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 2 of the Notes to Combined Financial Statements and Note 1 of the Notes to Unaudited Condensed Combined and Consolidated Financial Statements.

Assessing Impairment of Long-lived assets (including Intangible Assets) and Goodwill

The partnership assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. During the nine months ended September 30, 2013, the partnership recorded a $12 million impairment on the Service Star business line, a component of our gathering and processing business segment. The partnership recorded no other material impairments in the nine months ended September 30, 2013 and 2012 or the years ended December 31, 2012, 2011 or 2010.

The partnership assesses its goodwill for impairment at least annually by comparing the fair value of the reporting unit with its book value, including goodwill. The partnership tested its goodwill for impairment on May 1, 2013 upon formation and following formation intends to begin testing annually on October 1. The partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. The partnership performs its goodwill impairment testing one level below the Transportation and Storage and Gathering and Processing business segment at the operating segment level.

Because quoted market prices for the partnership's reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management considered observable transactions in the market, as well as trading multiples and cost of capital for peers, to determine appropriate multiples and discount rates to apply against historical and forecasted cash flows. A lower fair value estimate in the future for any of the partnership's reporting units could result in a goodwill impairment. Factors that could trigger a lower fair value estimate include sustained price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets. Based on the partnership's most recent goodwill impairment test, management concluded that the fair value of each reporting unit exceeded the carrying value of the reporting unit and none of the reporting units was at risk of failing step one of the impairment test. The partnership recorded no impairments of goodwill in the nine months ended September 30, 2013 and 2012 or the years ended December 31, 2012, 2011 and 2010.

Revenues

Revenues for gathering, processing, transportation and storage services for the partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts Receivable on the Combined or Consolidated Balance Sheets and in Revenues on the Combined and Consolidated Statements of Income.

The partnership recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

The partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The partnership has no material deferred revenues on the Combined or Consolidated Balance Sheets as of September 30, 2013, December 31, 2012 or December 31, 2011.

Natural Gas Purchases

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Combined or Consolidated Balance Sheets and in Cost of Goods Sold, excluding depreciation and amortization on the Combined and Consolidated Statements of Income.

Valuation of Assets

The application of business combination and impairment accounting requires the partnership to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires the partnership to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. The partnership records intangible assets separately from goodwill and amortizes intangible assets with finite lives over their estimated useful life as determined by management. The partnership does not amortize goodwill but instead annually assesses goodwill for impairment.

In the nine months ended September 30, 2013 and 2012 and the year ended December 31, 2012, the partnership completed acquisitions accounted for as business combinations as discussed in Note 6 of the Notes to Combined Financial Statements and Note 3 of the Notes to Unaudited Condensed Combined and Consolidated Financial Statements. As part of these acquisitions, the partnership has engaged the services of third-party valuation experts to assist it in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of the partnership's management. The partnership bases its estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

Depreciable Lives of Property, Plant and Equipment and Amortization Methodologies Related to Intangible Assets

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Commitments and Contingencies

In the normal course of business, the partnership is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the partnership has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the partnership's Combined Financial Statements and Unaudited Condensed Combined and Consolidated Financial Statements.

Except as disclosed otherwise in this Form S-1, the partnership believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the partnership's consolidated financial position, results of operations or cash flows. See Note 10 of Notes to Combined Financial Statements, Note 11 of the Notes to Unaudited Condensed Combined and Consolidated Financial Statements and under "Business—Legal Proceedings" for a discussion of the partnership's commitments and contingencies.

INDUSTRY OVERVIEW

General

We provide gathering and processing and transportation and storage services to producers and users of natural gas. We own an emerging crude oil gathering business and are constructing additional crude oil gathering assets to provide gathering and processing services to producers and users of crude oil. The market we serve, which begins at the point of production and extends to the end-user customer, is commonly referred to as the "midstream" market.

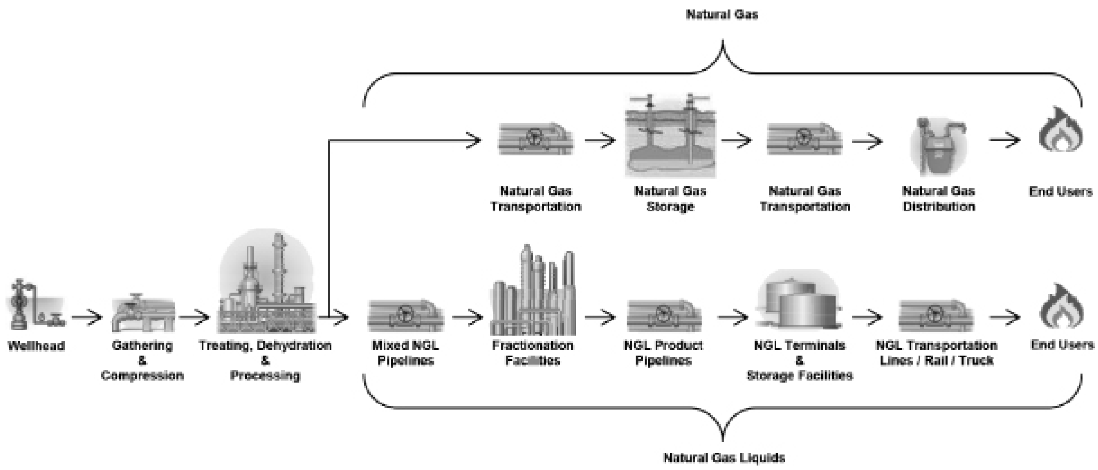
Natural Gas Industry Overview

The midstream natural gas industry is the link between the exploration and production of natural gas from the wellhead or lease and the delivery of the natural gas and its other components either to end-use markets, such as power generators and industrial consumers, or to LDCs, that make delivery to small commercial, industrial and residential consumers. Companies within this industry create value at various stages along the natural gas value chain by gathering natural gas from producers at the wellhead, processing and separating the hydrocarbons from impurities and into lean gas (primarily methane) and NGLs and then routing the separated lean gas and NGL streams for delivery to end-markets or to the next intermediate stage of the value chain.

A significant portion of natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically contains higher concentrations of NGLs than natural gas produced from gas wells. This rich natural gas is generally not acceptable for transportation in the nation's transmission pipeline system or for residential or commercial use. Processing plants extract the NGLs, leaving residual lean gas that meets transmission pipeline quality specifications for ultimate consumption. Furthermore, processing plants produce marketable NGLs, which, on an energy equivalent basis, typically have a greater economic value as a raw material for petrochemicals and motor gasolines than as a component of the natural gas stream.

Our gathering and processing operations provide gathering and processing of natural gas from Mid-Continent basins and then flow that gas into our transportation and storage systems. Our transportation and storage operations deliver and store gas from Mid-Continent producing basins to a range of customers, including LDCs and electric utilities in nine states, including Oklahoma, Texas, Arkansas, Louisiana, Illinois and Florida.

The following diagram illustrates the groups of assets commonly found along the natural gas value chain:



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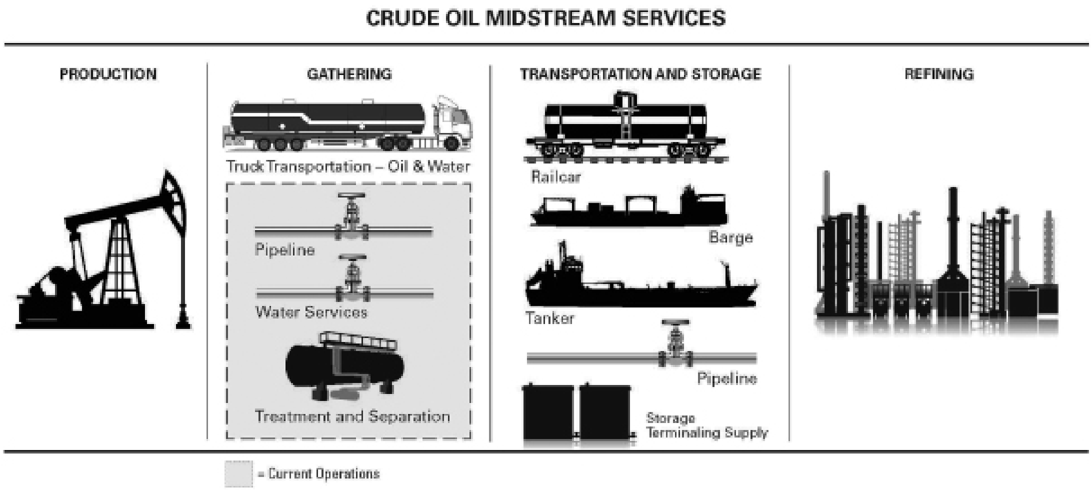
Crude Oil Industry Overview

Refined petroleum products, such as jet fuel, gasoline and distillate fuel oil, are all sources of energy derived from crude oil. The diagram below depicts the segments of the crude oil value chain:



Natural Gas Midstream Services

The services provided by us and other midstream natural gas companies are generally classified into the categories described below.

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, pad sites or other receipt points in the production area. These gathering systems transport natural gas from the wellhead to downstream pipelines or 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. A by-product of the gathering process is the recovery of condensate liquids, which are sold on the open market.

Compression

Gathering systems are operated at pressures intended to 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 to maintain throughput across the gathering system.

Treating and Dehydration

Treating and dehydration 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 cannot consume and 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 water and is chemically treated to separate the impurities from the natural gas stream.

Processing

Once the impurities are removed, pipeline-quality residue gas is separated from NGLs. Most rich natural gas is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components. The removal and separation of hydrocarbons during processing is possible because of the differences in physical properties between the components of the raw gas stream. There are four basic types of natural gas processing methods: cryogenic expansion, lean oil absorption, straight refrigeration and dry bed absorption. Cryogenic expansion represents the latest generation of processing, incorporating extremely low temperatures and high pressures to provide the best processing and most economical extraction.

Natural gas is processed not only to remove heavier hydrocarbon components that would interfere with pipeline transportation or the end use of the natural gas, but also to separate from the natural gas those hydrocarbon liquids that could have a higher value as NGLs than as natural gas. The principal component of residue gas is methane, although some lesser amount of entrained ethane typically remains. In some cases, processors have the option to leave ethane in the gas stream or to recover ethane from the gas stream, depending on ethane’s value relative to natural gas. The processor’s ability to “reject” ethane varies depending on the downstream pipeline’s quality specifications. The residue gas is sold to industrial, commercial and residential customers and electric utilities. We refer to the price of NGLs in relation to the price of natural gas as the “fractionation spread.”

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 other industrial end users. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids to take advantage of the difference in the boiling points of separate products.

Transportation and Storage

Once the raw natural gas has been treated or processed and the raw NGL mix fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. The U.S. natural gas pipeline grid transports natural gas from producing regions to customers, such as LDCs, industrial users and electric generation facilities. The concentration of natural gas production in a few regions of the United States generally requires transportation pipelines to transport gas not only within a state but also across state borders to meet national demand. Many pipeline systems have storage capacity connected to the pipeline network, ideally but not necessarily near major market centers, to help meet seasonal demand to manage daily supply-demand shifts on the network.

Interstate pipelines carry natural gas in interstate commerce and are subject to FERC regulation on (1) the rates charged for their services, (2) the terms and conditions of their services, and (3) the location, construction and abandonment of their facilities. Intrastate pipelines transport natural gas within a particular state and are typically not subject to plenary FERC regulation, but may be regulated by state agencies or commissions.

Natural gas storage plays a vital role in maintaining the reliability of gas available for deliveries. Natural gas is typically stored in underground storage facilities, including salt dome caverns and depleted reservoirs. Storage facilities are utilized by (1) pipelines, to manage temporary imbalances in operations, (2) natural gas end-users, such as LDCs, to manage the seasonality and variability of demand and to satisfy future natural gas needs and (3) independent natural gas marketing and trading companies in connection with the execution of their trading strategies.

Crude Oil Gathering

Pipeline transportation is generally the lowest cost method for shipping crude oil and transports about two-thirds of the petroleum shipped in the United States. Crude oil pipelines transport oil from the wellhead to logistics hubs and/or refineries. Common carrier pipelines have published tariffs that are regulated by the FERC or state authorities. Pipelines not engaged in the interstate transportation of crude may also be proprietary or leased entirely to a single customer. Crude oil gathering assets generally consist of a network of smaller diameter pipelines that are connected directly to the well site or central receipt points delivering into larger diameter trunk lines. Logistic hubs like Cushing, Oklahoma provide storage and connections to other pipeline systems and modes of transportation, such as barges, railroads and trucks. Trucking complements pipeline gathering systems by gathering crude oil from operators at remote wellhead locations not served by pipeline gathering systems. Trucking is generally limited to low volume, short haul movements because trucking costs escalate sharply with distance, making trucking the most expensive mode of crude oil transportation.

Barges and railroads provide additional transportation capabilities for shipping crude oil between gathering storage systems, pipelines, terminals and storage centers and end-users. Barge transportation is typically a cost-efficient mode of transportation that allows for the ability to transport large volumes of crude oil over long distances.

Competition in the crude oil gathering industry is typically regional and based on proximity to crude oil producers, as well as access to attractive delivery points. Overall demand for gathering services in a particular area is generally driven by crude oil producer activity in the area.

Contractual Arrangements

Midstream natural gas and crude oil services, other than transportation and storage, are usually provided under contractual arrangements that vary in the amount of commodity price risk they carry. Three typical types of contracts are described below.

- *Fee-Based Arrangements.* Under fee-based arrangements, the service provider typically receives a fee for each unit of natural gas gathered and compressed at the wellhead and an additional fee per unit of natural gas treated or processed at its facility. This fee is directly related to the volume of natural gas that flows through the gatherer’s or processor’s systems and is not directly dependent on commodity prices. Similarly, under fee-based crude oil arrangements, the service provider typically receives a fee tied to an applicable volumetric throughput tariff rate for each unit of crude oil gathered. As a result, the service provider bears no direct commodity price risk exposure. A sustained decline in commodity prices could, however, result in a decline in volumes and, thus, a decrease in the gatherer’s or processor’s fee revenues. These arrangements provide minimal, if any, upside in higher commodity price environments.
- *Percent-of-Proceeds and Percent-of-Liquids Arrangements.* Under these arrangements, the processor generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. The price paid to producers is based on an agreed percentage of the actual proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. We refer to contracts in which the processor shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements, and contracts in which the processor receives proceeds from the sale of a percentage of the NGLs or the NGLs themselves as compensation for processing services as percent-of-liquids arrangements. Under percent-of-proceeds arrangements, the processor’s margin correlates directly with the prices of natural gas and NGLs. Under percent-of-liquids arrangements, the processor’s margin correlates directly with the prices of NGLs.

- *Keep-Whole Arrangements.* Under these arrangements, the processor processes raw natural gas to extract NGLs and pays to the producer the gas equivalent Btu value of raw natural gas received from the producer in the form of either processed gas or its cash equivalent. The processor is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, the processor's margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the gas equivalent Btu value of those NGLs. The profitability of these arrangements is subject not only to the commodity price risk of natural gas and NGL, but also to the price of natural gas relative to NGL prices. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. In order to mitigate the downside risk to the processor associated with the price spread between natural gas and NGLs, several companies, including us, introduced a fee that stipulates a minimum amount to be paid to the processor if the market for downstream liquids is lower than the gas equivalent Btu value of the gas that is removed from the stream and that must be paid by the producer.

There are two levels of service provisions commonly utilized in contracts for the transportation and storage of natural gas. Each level of service governs the availability of capacity on the service provider's system for a specific customer and the priority of movement of a specific customer's products relative to other customers, especially in the event that total customer demand for services exceeds available system capacity.

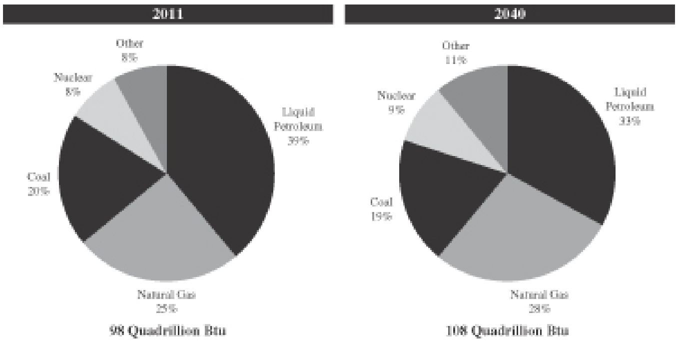
- *Firm.* Firm service requires the reservation of pipeline capacity by a customer between certain receipt and delivery points. Firm customers generally pay a "demand" or "capacity reservation" fee based on the amount of capacity being reserved, regardless of whether the capacity is used, plus a usage fee based on the amount of natural gas transported. Firm storage contracts involve the reservation of a specific amount of storage capacity, including injection and withdrawal rights, and generally include a capacity reservation charge based on the amount of capacity being reserved plus an injection and/or withdrawal fee.
- *Interruptible.* Interruptible service is typically short-term in nature and is generally used by customers that either do not need firm service or have been unable to contract for firm service. These customers pay a fee only for the volume of gas actually transported or stored. The obligation to provide this service is limited to available capacity not otherwise used by firm customers, and as such, customers receiving services under interruptible contracts are not assured capacity on the pipeline or at the storage facility.

U.S. Natural Gas Fundamentals

As indicated in the charts shown below, U.S. natural gas production and overall U.S. energy demand are expected to grow in the coming decades. Population is a large determinant of energy consumption through its influence on demand for travel, housing, consumer goods and services. The U.S. Energy Information Administration, or EIA, anticipates the total U.S. population will increase by approximately 29% from 2011 to 2040. Another important contributor to energy consumption is the industrial sector, with total consumption in this sector expected to grow to approximately 28.7 quadrillion Btu in 2040 compared to 24.0 quadrillion Btu in 2011, according to the EIA. According to the EIA, energy use is only projected to grow by approximately 10% from 2011 to 2040, and energy use per capita is expected to decline by approximately 15% over the same period. A review of other supply and demand elements follows.

Natural gas is a key component of energy consumption within the United States. According to the EIA, annual consumption of natural gas in the United States increased from approximately 24.3 quadrillion Btu in 2010 to approximately 24.9 quadrillion Btu in 2011. According to the EIA, natural gas consumption represented approximately 25% of total energy consumption in 2011, and the EIA projects that this percentage will increase to approximately 28% by 2040. The charts shown below illustrate energy consumption by fuel source in 2011 and expected energy consumption by fuel source in 2040.

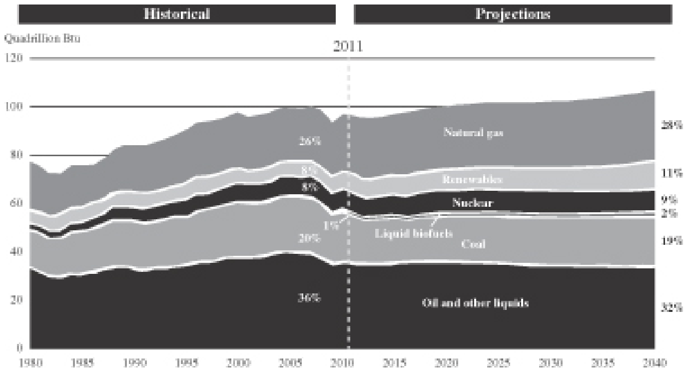
Energy Consumption by Fuel Source



Source: EIA, Annual Energy Outlook 2013 (April 2013).

The EIA expects that the growth of natural gas consumption relative to other fuel sources will be primarily driven by the use of natural gas electricity generation. According to the EIA, demand for natural gas in the electric power sector is projected to increase from approximately 7.6 Tcf in 2011 to approximately 9.5 Tcf in 2040, with a portion of the growth attributable to the retirement of 49 gigawatts of coal-fired capacity by 2022. The EIA also projects that natural gas consumption in the industrial sector will be higher due to the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slow price growth, particularly from 2011 through 2019, when the price of natural gas is expected to remain below 2010 levels. However, the EIA expects growth in natural gas consumption for power generation and in the industrial sector to be partially offset by decreased usage in the residential sector related primarily to decreased demand for natural gas supplied home heating.

U.S. Primary Energy Consumption by Fuel, 1980—2040



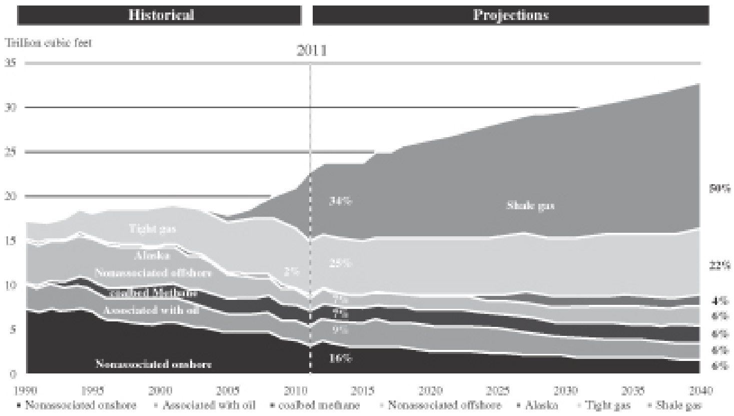
Source: EIA, Annual Energy Outlook 2013 (April 2013).

Domestic natural gas consumption today is satisfied primarily by production from onshore and offshore production in the lower 48 states, and is supplemented by production from historically declining pipeline imports from Canada, imports of LNG from foreign sources, and some Alaskan production.

In order to maintain current levels of U.S. natural gas supply and to meet the projected increase in demand, new sources of natural gas must continue to be developed to support consumption rates. Over the past several years, there has been a fundamental shift in U.S. natural gas production towards unconventional resources, which according to the EIA include natural gas produced from shale formations, tight gas and coal beds. The emergence of unconventional natural gas plays and advancements in technology have been crucial factors that have allowed producers to efficiently extract significant volumes of natural gas from these plays. According to the EIA, the dual application of horizontal drilling and hydraulic fracturing has been the primary driver of increases in shale gas production. As indicated by the diagram below, the development of these unconventional sources has offset declines in other, more traditional U.S. natural gas supply sources, which has helped meet growing consumption and lowered the need for imported natural gas. In fact, the EIA predicts that the United States will become a net exporter of natural gas starting in 2020.

As indicated by EIA forecasts shown in the diagram below, as the depletion of conventional onshore and offshore resources continues, natural gas from unconventional resource plays is forecasted to fill the void and continue to gain market share from higher-cost sources of natural gas. In fact, the EIA estimates that natural gas production from the major shale formations will provide the majority of the growth in domestically produced natural gas supply in coming years, increasing to approximately 50% in 2040 as compared with 34% in 2011. According to the EIA, shale gas will be the largest contributor to natural gas production growth. Tight gas and coal bed methane production will increase; however, the total composition of production from tight gas and coal bed methane will decline slightly.

U.S. Dry Natural Gas Production by Source, 1990—2040



Source: EIA, Annual Energy Outlook 2013 (Early Release Overview).

Overview of Areas of Operation

Our natural gas gathering, processing, transportation and storage assets and our crude oil gathering and processing assets are strategically located in four basins. We operate within multiple plays within these basins. These basins and plays are summarized below.

Anadarko Basin

The Anadarko basin is located across Western Oklahoma, southwestern Kansas, the northeastern part of the Texas Panhandle and the southeastern corner of Colorado. The Anadarko basin covers approximately 50,000 square miles. According to the U.S. Geological Survey, the basin has produced 2.3 billion barrels of oil and more than 65.5 Tcf of natural gas from 200,000 wells in its various formations. The Anadarko basin has recently been the focus of increased exploration activity. Horizontal drilling and multistate fracturing have resulted in the basin experiencing growth in oil and condensate production.

- *Cana Woodford Shale:* The Cana Woodford Shale (also known as the Anadarko Woodford) is found at depths ranging from 11,500 to 14,500 feet across Oklahoma. It is an extension of the Woodford Shale found in the Arkoma basin and produces rich gas from deeper formations. Operators have targeted the Woodford with horizontal laterals and multi-stage completions. As gas prices have fallen, operators have responded by moving rigs from the Arkoma basin Woodford in the east, which produces very lean gas, to southern zones of the Cana Woodford that have shown significant liquids content.
- *Granite Wash:* The Granite Wash Play spans an estimated 4,800 square miles across western Oklahoma and the north-eastern Texas Panhandle and is located at depths of 11,000 to 15,400 feet. Operators have drilled vertical wells in this part of the Anadarko basin for years. Production from the Granite Wash play in western Oklahoma and the Texas Panhandle dates back to the 1940s. Horizontal drilling and hydraulic fracturing have increased recovery factors significantly in recent years.
- *Mississippi Lime:* The Mississippi Lime play is located across Northern Oklahoma and Central and Northwestern Kansas. The formation has a relatively shallow depth, ranging from 3,000 to 6,000 feet. The Mississippian is a highly permeable oil play that is being developed by horizontal drilling.
- *South Central Oklahoma Oil Province (the SCOOP):* The SCOOP has a higher component of black oil than the northwest Cana Woodford. It covers much of four counties in south-central Oklahoma. The rock is an oil-rich portion of the Woodford Shale that lies beneath oil fields tapped by some of the state’s biggest producers.
- *Tonkawa/Cleveland Sands:* The Tonkawa and Cleveland Sands are shallow, oil-rich prospects that have recently seen an increase in drilling activity. The Cleveland formation was discovered in the mid 1950s and covers approximately 650 square miles. The Cleveland is a fine-grained, tight-gas formation that was initially developed using vertical wells. However, horizontal drilling has increased in the Cleveland as producers seek to maximize the production potential of the wells.

Ark-La-Tex Basin

The Ark-La-Tex basin is a mature, long-lived and prolific hydrocarbon producing province that produces oil and gas from several reservoirs and a variety of trap types. The basin has been a long-time target of conventional oil producers. As a result of technological advances, operators have recently begun exploring deeper into the more shale-like rock, which is contiguous across the basin. There are multiple oil-bearing targets within the basin.

- *Haynesville/Lower Bossier Shale:* The Haynesville/Bossier Shale is located in east Texas and western Louisiana and is found at intervals greater than 10,000 feet below the surface. The shale interval in east Texas is known as the Lower Bossier, and the shale interval in western Louisiana is referred to as the Haynesville. These formations are of a type once considered too costly to explore. However, in 2008, newer technology and processes led to increased activity as energy exploration companies began to lease property in preparation for possible drilling and production.
- *Cotton Valley:* The Cotton Valley formation is a tight gas play in northeast Texas and northwest Louisiana located just above the Haynesville/Bossier Shale. It consists of sandstone, limestone and shale. The depth of the Cotton Valley formation is roughly 7,800 to 10,000 feet. Although it is mainly a natural gas play, some oil has been produced in parts of the play.

Arkoma Basin

Located in west-central Arkansas and southeastern Oklahoma, the Arkoma basin is a historically prolific, largely gas-prone basin. The basin encompasses an area of approximately 33,800 square miles. The successful development of unconventional plays in the Arkoma basin is largely driven by the application of horizontal drilling and hydraulic fracture stimulation techniques to shale gas and tight gas plays.

- *Fayetteville Shale*: The Fayetteville Shale is situated in northern Arkansas and eastern Oklahoma and is located at depths of 1,000 to 7,000 feet. The total area for the Fayetteville shale play is 9,000 square miles. Horizontal drilling and hydraulic fracturing techniques made this play economical.

Williston Basin

According to the U.S. Department of Energy, the Williston Basin has seen strong production growth driven by the implementation of methods such as horizontal drilling and hydraulic fracturing. The basin spans eastern Montana, North Dakota and northwestern South Dakota in the United States and southern Saskatchewan and Manitoba in Canada. The Williston basin is approximately 300,000 square miles.

- *Bakken Shale Formation*: The Bakken shale formation is located across approximately 200,000 square miles of eastern Montana and North Dakota in the United States and southern Saskatchewan and Manitoba in Canada. The Bakken shale formation is an unconventional “continuous-type” oil resource, according to the EIA. In recent years, the success of the Bakken shale formation can be attributed to new drilling and completions technology. According to the EIA, North Dakota is now the nation’s second largest oil-producing state. Furthermore, the region now accounts for a little over 10% of total U.S. oil production according to the EIA. As reported in November 2013 by the EIA, the Bakken continues to grow, and producers in North Dakota’s Bakken shale formation will increase oil output to a record 1,002 MBbl/d by December 2013.

BUSINESS

Overview

We are a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. We serve key current and emerging production areas in the United States, including several premier, unconventional shale resource plays and local and regional end-user markets in the United States. Our assets and operations are organized into two business segments: (i) gathering and processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. In both business segments, we generate a substantial portion of our gross margin under long-term, fee-based agreements that minimize our direct exposure to commodity price fluctuations.

Our natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in some of the most productive regions of the Anadarko, Arkoma and Ark-La-Tex basins. These basins have experienced a strong increase in investment and drilling activity by exploration and production companies in recent years. We also own an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. We are continuing to construct additional crude oil gathering capacity in this area. Our natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Upon our formation in May 2013 as a limited partnership among OGE Energy, CenterPoint Energy and ArcLight, we became one of the largest midstream partnerships in the United States based on total assets. As of September 30, 2013, our portfolio of energy infrastructure assets included approximately 11,000 miles of gathering pipelines, 11 major processing plants with approximately 1.9 Bcf/d of processing capacity, approximately 7,800 miles of interstate pipelines (including SESH), approximately 2,300 miles of intrastate pipelines and eight storage facilities comprising 86.5 Bcf of storage capacity. We believe our scale benefits our customers by providing them with fully integrated midstream services and improved access from the wellhead to the marketplace. In addition, we believe our scale and scope will position us to be more competitive in developing new energy infrastructure assets and adding complementary services and business lines.

From the year ended December 31, 2010 through the nine month period ended September 30, 2013, on a pro forma basis, we grew the volume of natural gas gathered on our systems by 17%. Over the same time period, the volume of gas processed on our systems grew by 49% on a pro forma basis. We expect to continue to grow our business by providing midstream services to our customers' rapidly growing upstream development projects. We expect our customers' activity in the basins in which we operate to result in higher throughput on our systems and additional organic growth opportunities to expand the capacity and utilization of our assets. We also expect to grow our business and distributable cash flow by developing new energy infrastructure projects to support new and existing customers as they expand beyond our current footprint, as well as through third-party acquisitions. For the years ended December 31, 2011 and 2012, on a pro forma basis, we invested $831 million and $912 million, respectively, in expansion capital expenditures. During the nine months ended September 30, 2013, on a pro forma basis, we invested $405 million in expansion capital expenditures. We expect that our expansion capital expenditures will be $448 million for the year ending December 31, 2014.

We believe that our contractual arrangements provide a strong platform to support established operations and future organic growth. For the nine months ended September 30, 2013, on a pro forma basis, approximately 75% of our gross margin was generated from contracts that are fee-based, and approximately 50% of our gross margin was attributable to firm contracts or contracts with minimum volume commitment features.

For the nine months ended September 30, 2013, on a pro forma basis, we generated $984 million of gross margin, $586 million of Adjusted EBITDA and $338 million of net income. Gross margin and Adjusted EBITDA are non-GAAP financial measures. For definitions of gross margin and Adjusted EBITDA and a reconciliation to their most directly comparable financial measures calculated in accordance with GAAP, please read "Summary—Summary Historical and Pro Forma Financial and Operating Data—Non-GAAP Financial Measures."

Gathering and Processing. We provide gathering, processing, treating, compression, dehydration and NGL fractionation for natural gas producers. Our gathering and processing assets are strategically located in established and actively developing basins in the United States and are interconnected with our interstate and intrastate pipelines and with third-party pipelines, which provides our customers with the benefits of a flexible and efficient transportation and storage system. On a pro forma basis for the nine months ended September 30, 2013, our top customers by volumes gathered were affiliates of Encana, Shell, Exxon, Chesapeake, Apache, Continental, QEP, Devon, BP and Samson.

The following table sets forth certain information regarding our gathering and processing assets on a pro forma basis as of or for the nine months ended September 30, 2013:

Asset/Basin	Length (miles)	Compression (Horsepower)	Average Gathering Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (Bbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	6,550	594,500	1.3	8	1,245	42,700	4.7
Arkoma Basin	2,700	115,600	1.0	1	60	4,700	1.2
Ark-La-Tex Basin(1)	1,600	182,900	1.3	2	545	10,900	0.7
Total	10,850	893,000	3.6	11	1,850	58,300	6.6

(1) Ark-La-Tex basin assets also include 14,500 Bbl/d of fractionation capacity and 6,300 Bbl/d of ethane pipeline capacity, which are not listed in the table.

Five of our processing plants in the Anadarko basin are interconnected via our large-diameter, rich gas gathering system in western Oklahoma, which spans 18 counties and has approximately 1.0 Bcf/d of processing capacity. Our 4.7 million gross acres of acreage dedications in the Anadarko basin area are served by this system, which we refer to as our "super-header" system. We have configured this system to optimize the flow of natural gas and the utilization of the processing plants connected to it, which we believe provides us with strategic growth opportunities. We have made investments to expand the super-header system and continue to grow its capacity through the planned addition of two new cryogenic processing plants and related gathering pipelines. One of these two new plants, which is located in Custer County, Oklahoma (the McClure Plant), will increase our natural gas processing capacity in the basin by over 15%, providing an additional 200 MMcf/d of natural gas processing capacity. The McClure Plant is expected to be completed in the first quarter of 2014. The other new plant, which will be located in Grady County, Oklahoma (the Bradley Plant), will provide an additional 200 MMcf/d of processing capacity and is expected to be completed in the first quarter of 2015.

We believe our contract structures provide us with stable cash flows in our major operating basins. For the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, we generated 60% and 56%, respectively, of our gathering and processing gross margin under long-term, fee-based agreements, and of this fee-based margin, approximately 38% and 40%, respectively, was attributable to gathering and processing contracts containing minimum volume commitment features. Under our minimum volume commitment contracts, our customers commit to ship a minimum annual volume of natural gas on our gathering system, or, in lieu of shipping such volumes, to pay us periodically as if that minimum amount had been shipped. As of September 30, 2013, we had minimum volume commitments in lean natural gas developments of 1.6 Bcf/d with a weighted average remaining term of over nine years. We also have an emerging crude oil gathering business in the Bakken shale formation with a similar minimum volume commitment contract structure that we believe will provide us with an additional source of stable cash flows.

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Under our acreage dedication contracts, our customers are generally required to deliver all of their production within the dedicated area to our gathering system for processing over the period of the contract. As of September 30, 2013, we had acreage dedications in rich natural gas developments covering more than 5.7 million acres that generally have long lived reserves with a weighted average remaining term of approximately nine years. As of September 30, 2013, our gathering and processing contracts for our top ten natural gas producer customers, which accounted for approximately 75% of our gathered volumes for the nine months ended September 30, 2013, on a pro forma basis, had a volume-weighted average remaining term of approximately nine years.

For the nine months ended September 30, 2013, on a pro forma basis, our gathering and processing business segment generated $560 million of gross margin and $338 million of Adjusted EBITDA.

Transportation and Storage. Our natural gas transportation and storage business segment consists of our interstate pipelines, our intrastate pipelines and our storage assets. We provide pipeline takeaway capacity for natural gas producers from supply basins to market hubs and critical natural gas supply for industrial end users and utilities, such as LDCs and power generators. Our interstate pipeline system, including SESH, includes approximately 7,800 miles of transportation pipelines and extends from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois. Our eight storage facilities in Oklahoma, Louisiana and Illinois have 86.5 Bcf of storage capacity and strategically complement our pipeline systems.

The following table sets forth certain information regarding our transportation and storage assets as of September 30, 2013:

Asset	Length (miles)	Capacity	Total Firm Contracted Capacity (Bcf/d)	Average Throughput Volume (Tbtu/d)	Percent of Capacity under Firm Contracts	Weighted Average Remaining Firm Contract Life (years)
Interstate Transportation(1)	7,800	8.4 Bcf/d	7.2	3.5(2)	86%	4.1
Intrastate Transportation	2,300	1.9 Bcf/d(3)	—	1.6	—	5.4
Storage	—	86.5 Bcf	67.9	—	79%	4.7

(1) Except with respect to length, this information does not include amounts for SESH. SESH is a non-consolidated entity in which we own a 24.95% ownership interest.

(2) Actual volumes transported per day may be less than total firm contracted capacity based on demand.

(3) This represents the maximum single day receipts on the intrastate systems. Our Oklahoma intrastate pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits our ability to determine an overall system capacity. During the nine months ended September 30, 2013, the peak daily throughput was 1.9 TBtu or, on a volumetric basis, 1.9 Bcf/d.

We generate revenue primarily by charging demand fees pursuant to applicable tariffs for the transportation and storage of natural gas on our system. We generate 96% of our transportation and storage gross margin under fee-based agreements with a weighted average remaining contract life of approximately five years as of September 30, 2013. Demand-based margin for this period represented 89% of the fee-based margin. We generally do not take ownership of the natural gas that we transport and store.

For the nine months ended September 30, 2013, on a pro forma basis, our top customers by gross margin were affiliates of CenterPoint Energy, Laclede, Exxon, OGE Energy and AEP. Our transportation and storage assets were designed and built to serve affiliates of CenterPoint Energy, Laclede, OGE Energy and AEP and are competitively positioned to serve other large natural gas and electric utility companies, such as Ameren and Entergy.

For the nine months ended September 30, 2013, on a pro forma basis, our transportation and storage business segment generated $426 million of gross margin and $248 million of Adjusted EBITDA.

Business Strategies

Our primary business objective is to practice operational excellence and to grow our business responsibly, enabling us to increase the amount of cash distributions we make to our unitholders over time while maintaining our financial stability. We intend to accomplish this objective by executing the strategies listed below:

- *Capitalize on Organic Growth Opportunities Associated with Our Strategically Located Assets.* We own and operate assets servicing four of the largest basins in the United States, including some of the most productive shale developments in these basins. We believe current high levels of natural gas and crude oil exploration, development and production activities within our areas of operation present significant opportunities for organic growth and increasing throughput on our system. Over 200 drilling rigs were deployed in our areas of operation as of September 30, 2013, which represents a 12% increase over December 2012. As a result of this expanding activity, we are constructing two processing facilities in Oklahoma that are expected to provide an additional combined 400 MMcf/d in processing capacity. We are currently evaluating other expansion opportunities to further enhance our existing systems.
- *Continue to Minimize Direct Commodity Price Exposure Through Long-Term, Fee-Based Contracts.* We continually seek ways to minimize our exposure to commodity price risk, and we believe that our focus on fee-based revenues reduces our direct commodity price exposure and is essential to maintaining stable cash flows and increasing our quarterly distributions over time. Since 2009, we have focused on increasing the percentage of long-term, fee-based contracts with our customers. For the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, 75% of our gross margin was generated from fee-based contracts. As we grow, we intend to maintain our focus on long-term, fee-based contracts.
- *Maintain Strong Customer Relationships to Attract New Volumes and Expand Beyond Our Existing Asset Footprint and Business Lines.* We plan to grow our business through our strong relationships with existing customers. We believe that we have built a strong and loyal customer base through exemplary customer service and reliable project execution. We have invested in multiple organic growth projects in support of our existing and new customers. For example, in 2012, an existing customer invited us to participate in the construction of a gas gathering system in the Ark-La-Tex basin, and in 2013, a second customer invited us to develop a crude oil gathering system in the Williston basin. We expect to maintain and build relationships with key producers and suppliers to continue to attract new volumes and expansion opportunities.
- *Grow Through Accretive Acquisitions and Disciplined Development.* We plan to pursue accretive acquisitions of complementary assets that provide attractive potential returns in new operating regions or midstream business lines. From January 1, 2010 through September 30, 2013, on a pro forma basis, we have invested approximately $639 million in acquisitions of new assets (including our Waskom processing plant, Cordillera gathering system and Amoruso gathering system) and investments in joint ventures (including SESH), and we have invested an additional $160 million in expansion capital associated with these projects. We also have the ability to acquire CenterPoint Energy's remaining 25.05% interest in SESH by 2015. We will continue to analyze acquisition opportunities using disciplined financial and operating practices, including a process for evaluating and managing risks to cash distributions.
- *Leverage the Scale of Our Existing Assets to Realize Significant Synergies.* Given the complementary features of our assets, we expect operating synergies from the interconnection and optimization of our

systems to increase our cash flows over time. We expect to achieve operational and commercial synergies of $12.5 million through December 31, 2014, net of integration costs, and we expect additional synergies over time as we create a combined midstream service platform and are able to offer new and existing customers new and more efficient services.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully because of the following competitive strengths:

- *Significant Capability, Scale and Stability of Our Diversified Midstream Business.* With approximately $11 billion in assets as of September 30, 2013 across ten states and multiple midstream business lines, we have an enhanced ability to provide customers with access to diverse services and end markets. We have approximately 11,000 miles of gathering pipelines and 11 major processing plants with approximately 1.9 Bcf/d of processing capacity spanning the Anadarko, Arkoma and Ark-La-Tex basins. Our natural gas processing plants produced 58.3 MBbl/d of NGLs, on a pro forma basis, for the nine months ended September 30, 2013, making us one of the largest producers of NGLs in the United States. Our network of interstate and intrastate pipelines covers approximately 7,800 miles (including SESH) and 2,300 miles, respectively, and is complemented by our 86.5 Bcf of storage capacity. We believe our size, scale and stability are competitive strengths and enhance our ability to provide reliable and increasing cash flows to our unitholders.
- *Strategically Located Assets that Provide a Strong Platform for Growth and Operational Flexibility to Our Customers.* Our assets are strategically configured in and around four of the most prominent natural gas and crude oil producing basins in the country and support a diversified midstream business that we believe will deliver reliable distributions and steady growth to our unitholders. Our assets transport natural gas to delivery points across the United States through 97 interconnects as of September 30, 2013. A portion of our system also serves local natural gas demand at LDCs, natural gas-fired power plants and industrial load in the regions in which we operate. We believe that our assets provide operational flexibility and delivery options for producers transporting natural gas from a mix of rich and lean natural gas plays to multiple market hubs within our region. Our assets also provide outlets for suppliers from other regions seeking to provide natural gas to on-system markets that we serve. We believe that our competitors would require significant capital expenditures to provide comparable services to these customers, providing us with a significant competitive advantage as demand for natural gas grows over time.
- *Strong Relationships with a Large and Diverse Customer Base.* We serve a broad range of customers across both of our business segments, and many of our customers rely on us for multiple midstream services. We believe that our track record of executing large infrastructure projects and meeting target in-service dates has allowed us to build a reputation as a reliable operator that provides high-quality services and focuses on the needs of our customers. On a pro forma basis for the nine months ended September 30, 2013, our top gathering and processing customers by volumes gathered were affiliates of Encana, Shell, Exxon, Chesapeake, Apache, Continental, QEP, Devon, BP and Samson and our top transportation and storage customers by gross margin were affiliates of CenterPoint Energy, Laclede, Exxon, OGE Energy and AEP. We believe that our relationships and reputation will continue to create opportunities with new and existing customers.
- *Stable Cash Flows as a Result of Fee-Based Revenues Under Long-Term Contracts.* For both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, we generated approximately 75% of our gross margin from fee-based contracts, primarily with creditworthy counterparties. We believe that our long-term, fee-based contracts, many of which include minimum volume commitments and/or acreage dedications, minimize our commodity price exposure and enhance the predictability of our financial performance.

- *Strong and Flexible Capital Structure.* We have a disciplined financial policy and maintain a strong and flexible capital structure to allow us to execute our identified growth projects and acquisitions even in challenging market environments. On May 1, 2013, we entered into our $1.4 billion five-year senior unsecured revolving credit facility, and we expect to have approximately $ million of available borrowing capacity under this facility upon the closing of this offering. We believe our strong credit profile, including our investment-grade credit ratings, and the liquidity provided by our revolving credit facility give us a significant advantage over many of our competitors that may be more limited in their access to capital to pursue organic growth and acquisition opportunities.
- *Experienced Management Team and Key Operational Personnel with a Proven Record of Asset Operation, Acquisition, Construction, Development and Integration Expertise.* Our management team has an average of over years of experience in the energy industry in operating, acquiring, constructing, developing and integrating midstream assets, and understands the service requirements of our customers. Our management team has established strong relationships with producers, marketers and other end-users of natural gas throughout the U.S. upstream and midstream industries, which we believe will be beneficial to us in pursuing acquisition and organic expansion opportunities. We also employ skilled engineering, construction and operations teams that have significant experience in designing, constructing and operating large midstream energy projects.

Our Sponsors

OGE Energy and CenterPoint Energy are aligned with us to grow our distributions. Following the completion of this offering, OGE Energy and CenterPoint Energy will retain a significant interest in us through their approximate % and % limited partner interests in us, respectively. OGE Energy and CenterPoint Energy will each own 50% of the management rights of our general partner and will own all of our incentive distribution rights.

OGE Energy (NYSE: OGE) is the parent company of OG&E, a regulated electric utility serving approximately 805,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas. OG&E furnishes retail electric service in 268 communities and their contiguous rural and suburban areas. OG&E's service area includes Oklahoma City, Oklahoma and Fort Smith, Arkansas, the second largest city in that state. Of the 268 communities that OG&E serves, 242 are located in Oklahoma and 26 are located in Arkansas. As of September 30, 2013, OGE Energy had total assets of $9.1 billion and a market capitalization of $7.2 billion.

CenterPoint Energy (NYSE: CNP) is a public utility holding company whose indirect wholly owned subsidiaries include (i) CenterPoint Energy Houston Electric, LLC, which provides electric transmission and distribution services to retail electric providers serving over two million metered customers in a 5,000-square-mile area of the Texas Gulf Coast that has a population of approximately six million people and includes the city of Houston; and (ii) CenterPoint Energy Resources Corp., which owns and operates natural gas distribution systems serving more than three million customers in six states, including customers in the metropolitan areas of Houston, Texas; Minneapolis, Minnesota; Little Rock, Arkansas; Shreveport, Louisiana; Biloxi, Mississippi; and Lawton, Oklahoma. As of September 30, 2013, CenterPoint Energy had total assets of $21.6 billion and a market capitalization of $10.3 billion.

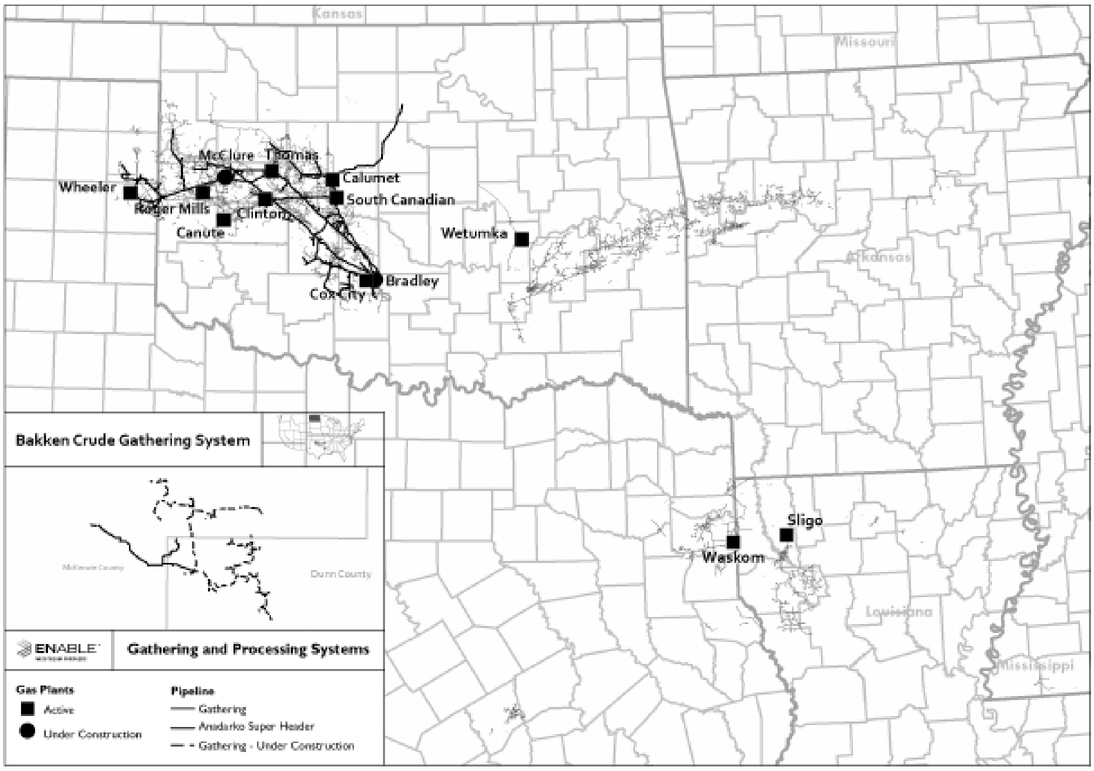
Our sponsors are also significant customers of our transportation and storage business segment and continue to own and operate a substantial portfolio of energy assets. For both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 4% of our total gross margin was derived from contracts servicing electric power generation with OGE Energy. For both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 7% of our total gross margin was derived from contracts servicing LDCs owned by CenterPoint Energy.

Our sponsors entered into a number of agreements in connection with our formation. Please read "Certain Relationships and Related Party Transactions" for a detailed description of these agreements, as well as other agreements affecting us and our sponsors.

Our Assets and Operations

Our assets and operations are organized into two business segments: gathering and processing and transportation and storage.

Gathering and Processing



General. We own and operate approximately 11,000 miles of natural gas gathering pipelines in the Anadarko, Arkoma and Ark-La-Tex basins with approximately 893,000 horsepower of compression and 11 natural gas processing plants with approximately 1.9 Bcf/d of processing capacity as of September 30, 2013. We provide gathering, compression, treating, dehydration, processing and NGL fractionation for producers who are active in the areas in which we operate. For the nine months ended September 30, 2013, on a pro forma basis, our assets gathered an average of approximately 3.6 TBtu/d of natural gas. In addition, we have the capacity to treat and process up to 1.9 Bcf/d of natural gas. For the nine months ended September 30, 2013, on a pro forma basis, we processed approximately 1.46 TBtu/d of natural gas and produced approximately 58.3 MBbl/d of NGLs. We also have an emerging crude oil gathering business and are currently constructing additional crude oil gathering assets in the Bakken shale formation, principally located in the Williston basin, that commenced initial operations in November 2013.

We serve some of the most prolific shale developments in the country through our operations in the following basins:

- *Anadarko Basin (Oklahoma, Texas Panhandle).* We currently operate in the liquids-rich Granite Wash, Cleveland, Tonkawa, Cana Woodford, SCOOP and Mississippi Lime plays. As of September 30, 2013, our assets include approximately 6,550 miles of natural gas gathering pipelines and eight natural gas processing plants. We also have two processing plants under construction that will add 400 MMcf/d of processing capacity. For the nine months ended September 30, 2013, on a pro forma basis, this system had average daily gathered throughput of approximately 1.3 TBtu/d of natural gas and produced 42,700 Bbl/d of NGLs. We have secured 4.7 million gross acres dedicated via long-term contracts in this basin. The majority of these arrangements are fee-based with long-term acreage dedications. These contracts provide for gathering and compression services, which are typically fee-based, and processing services under fee-based, percent-of-liquids or percent-of-proceeds structures.
  - In the Greater Granite Wash area, we currently serve over 97 producers and have approximately 2.7 million gross acres dedicated through long-term contracts. These contracts provide for gathering and compression services, which are typically fee-based, and processing services under fee-based, percent-of-liquids or percent-of-proceeds structures.
  - In the Cana/Woodford Shale area we currently serve 119 producers and have over 1.1 million gross acres dedicated through long-term contracts. These contracts are long-term and provide for processing of rich gas via fee-based and fee-enhanced percent-of-proceeds structures. This area consists of the Northwest Cana area, which is generally considered a lean gas area, and the SCOOP, which is generally considered a rich gas area. In June 2012, we entered into a contract with a producer that covers over 0.5 million gross acres across portions of seven counties in the SCOOP area of the Cana/Woodford. This contract is long-term and structured as a fee-enhanced percent-of-proceeds contract.
  - We have recently expanded into the Mississippi Lime area of northern Oklahoma with 0.4 million gross acres dedicated.
- *Arkoma Basin (Oklahoma, Arkansas).* In Oklahoma, we operate in the rich and lean gas areas of the western portion of the Arkoma basin. In Arkansas, we operate in the eastern Arkoma and the Fayetteville shale play. As of September 30, 2013, our assets include approximately 2,700 miles of natural gas gathering pipelines and one natural gas processing plant. For the nine months ended September 30, 2013, on a pro forma basis, this system had average daily gathered throughput of approximately 1.0 TBtu/d of natural gas and produced 4,700 Bbl/d of NGLs. We currently serve over 220 producers in these areas and have secured over 1.2 million acres dedicated via long-term contracts in this basin. Additionally, in the lean gas area of the Fayetteville shale we have secured contracts that are volume-based, providing certainty of minimum revenues in time periods when natural gas prices are depressed.
- *Ark-La-Tex Basin (Arkansas, Louisiana and Texas).* We operate primarily in the Haynesville, Cotton Valley and the lower Bossier shale plays. As of September 30, 2013, our assets include approximately 1,600 miles of natural gas gathering pipelines, two natural gas processing plants, an NGL fractionation facility and approximately 40 miles of ethane pipelines. For the nine months ended September 30, 2013, on a pro forma basis, this system had average daily gathered throughput of approximately 1.3 TBtu/d of natural gas and produced 10,900 Bbl/d of NGLs. We currently serve over 110 producers in these areas and have secured over 0.7 million gross acres dedicated via long-term contracts in this basin. Additionally, in the lean gas area of the Haynesville shale we have secured contracts that are volume-based, providing certainty of minimum revenues in periods of time when natural gas prices are depressed.
- *Williston (North Dakota)*. We have recently expanded our service offerings with a long-term, minimum volume commitment agreement with an affiliate of Exxon to provide crude oil gathering in the Bakken shale formation, principally in the Williston basin, along with water transportation and other complementary services. In November 2013, we commenced initial operations on a new crude oil

gathering pipeline system in North Dakota's oil-rich Bakken shale formation, and we expect to place additional related assets in service in 2014. The gathering system, located in Dunn and McKenzie Counties in North Dakota, has a planned capacity of up to 19,500 barrels per day, all of which is contracted through September 2028.

We believe that our assets are strategically positioned to provide customers with access to preferred pipelines and premium markets. We also believe our businesses are positioned to capture new growth opportunities, such as crude oil production and NGL services, in our existing areas of operation and new areas across the United States.

As of September 30, 2013, our processing system consisted of 11 plants located in the Anadarko, Arkoma and Ark-La-Tex basins. The assets serving the Anadarko basin consist of eight processing plants, five of which are interconnected through our super-header system, and are configured to facilitate the flow of natural gas from western Oklahoma and the Wheeler County area in the Texas Panhandle to the Cox City, Thomas, Calumet, South Canadian or Wheeler processing plants. In addition, we are currently constructing a cryogenic processing facility (the McClure Plant) connected to our super-header system in Custer County, Oklahoma, which is expected to add 200 MMcf/d in throughput capacity and is expected to be completed in the first quarter of 2014. We are also currently constructing a cryogenic processing facility (the Bradley Plant) connected to our super-header system in Grady County, Oklahoma, which is expected to add 200 MMcf/d of natural gas processing capacity and is expected to be completed in the first quarter of 2015. This flexible gathering system is intended to allow us to optimize the economics of our natural gas processing and to improve system utilization and reliability. The plant in the Arkoma basin serves the rich gas western portion of the area. The two plants in the Ark-La-Tex basin serve the Haynesville, Cotton Valley and the lower Bossier plays.

The following table sets forth information with respect to our natural gas processing plants as of or for the nine months ended September 30, 2013:

Processing Plant	Year Installed	Type of Plant	Average Daily Inlet Volumes (MMcf)	Inlet Capacity (MMcf)
Anadarko				
Bradley	2015[1]	Cryogenic	—	200
McClure	2014[2]	Cryogenic	—	200
Wheeler	2012	Cryogenic	155	200
South Canadian	2011	Cryogenic	192	200
Clinton	2009	Cryogenic	84	120
Roger Mills[3]	2008	Refrigeration	31	100
Canute	1996	Cryogenic	54	60
Cox City	1994	Cryogenic	146	180
Thomas	1981	Cryogenic	117	135
Calumet	1969	Lean Oil	68	250
Ark-La-Tex				
Sligo[4]	2004	Refrigeration	65	225
Waskom	1940[5]	Cryogenic	230	320
Arkoma				
Wetumka	1983	Cryogenic	32	60
Total			1,174	2,250

(1) The Bradley Plant is under construction and estimated to be in service in the first quarter of 2015.
(2) The McClure Plant is under construction and estimated to be in service in the first quarter of 2014.
(3) All of our processing plants are located on properties that are owned by us except for Roger Mills, which is located on property that is leased.

(4) Average daily inlet volumes and inlet capacity includes 25 MMcf/d related to a separate cryogenic unit.
(5) A processing plant has been in operation on the Waskom plant site since 1940. The Waskom plant was upgraded to cryogenic in 1995.

Off-System Delivery Points. Our gathering lines interconnect with both our interstate and intrastate pipelines, as well as other interstate and intrastate pipelines, including the ETC Tiger, Acadian, Texas Eastern Transmission, Gulf South, Gulf Crossing, Panhandle Eastern, ANR, NGPL and Northern Natural pipelines. These connections provide producers with access to a diverse set of natural gas market hubs.

A significant amount of our NGLs are delivered into third-party pipelines and transported to Conway, Kansas or Mont Belvieu, Texas, where the NGLs are sold under contract or on the spot market. We sell the remaining NGLs as propane at the tailgate of three of our processing plants into local markets. Additionally, at our Waskom processing plant, we sell propane, butane and natural gasoline to local markets, and we operate a fractionator and an ethane pipeline and sell ethane to a single customer.

The natural gas that remains after processing is primarily taken in-kind by the producer customers into our pipelines for redelivery either to on-system customers, such as electric generation facilities and other end-users, or into downstream interstate pipelines. NGLs are typically sold to NGL marketers and end-users, and condensate liquid production is typically sold to marketers and refineries.

Customers. We generate revenues from several of the largest and most active producers in the basins in which we operate. On a pro forma basis for the nine months ended September 30, 2013, our top gathering and processing customers by volumes gathered were affiliates of Encana, Shell, Exxon, Chesapeake, Apache, Continental, QEP, Devon, BP and Samson. For the nine months ended September 30, 2013, on a pro forma basis, our top ten natural gas producer customers accounted for approximately 75% of our gathered volumes.

Contracts. We derive revenue pursuant to a variety of arrangements, including fee-based, percent-of-proceeds, percent-of-liquids and keep-whole arrangements. For the nine months ended September 30, 2013, on a pro forma basis, 60% of our gathering and processing gross margin is generated under long-term, fee-based contracts.

The remaining 40% of margin for the nine months ended September 30, 2013 came from commodity-based contracts, such as percent-of-proceeds, percent-of-liquids or keep-whole arrangements. For the nine months ended September 30, 2013, on a pro forma basis, contracts generating 38% of our fee-based percentage had minimum volume commitments with remaining terms ranging from five to 14 years. Under a minimum volume commitment, a customer commits to ship a minimum volume of natural gas over a period of time on our gathering system, or, in lieu of shipping such volumes, to pay as if that minimum amount had been shipped and the sale of commodities gathered through the operation of our gathering business.

In addition, as of September 30, 2013, our agreements also have acreage dedications with original terms ranging up to 15 years, which generally require that production by our customers within the acreage dedication be delivered to our gathering system for processing. As of September 30, 2013, our gathering agreements had acreage dedications of 6.6 million gross acres with a volume weighted average remaining term of approximately nine years.

The following table sets forth information with respect to our processing contracts for the periods indicated below, on a pro forma basis.

	Processing Arrangements		
	Fee-Based	Percent-of-Proceeds/ Percent-of-Liquids	Keep-Whole
Nine months ended September 30, 2013	47%	45%	7%
Year ended December 31, 2012	38%	44%	18%
Year ended December 31, 2011	39%	39%	22%
Year ended December 31, 2010	38%	35%	27%

We have the ability to enhance gross margin generated from our gathering and processing contracts through the use of multiple processing plant locations and our processing super-header. Our large diameter, rich gas gathering pipelines in western Oklahoma are configured to allow natural gas from western Oklahoma and the Wheeler County area in the Texas Panhandle to flow to the Cox City, Thomas, Calumet, South Canadian or Wheeler processing plants and to maximize margins from our contracts by choosing the most economical operational configuration given the market conditions at the time, including ethane rejection scenarios.

Competition. Competition to gather and process natural gas is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. We believe that we are well positioned to compete on these bases. Our gathering and processing systems compete with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. Our primary competitors are master limited partnerships who are active in the regions where we operate. In the process of selling NGLs, we compete against other natural gas processors extracting and selling NGLs.

Growth Opportunities for Gathering and Processing Business Segment

Over the past several years we have initiated multiple organic growth projects, investing heavily in the expansion of our gathering and processing footprint, primarily in the rich gas Anadarko and Arkoma basins. Since January 2010, on a pro forma basis, we have invested over $2.9 billion in total gathering and processing infrastructure in order to capture natural gas resulting from the surge in drilling. Our spending has been influenced by several recent producer trends and other current market conditions, including the shift in focus to rich gas plays and crude oil plays across the basins we serve. We believe that this increased interest in crude oil plays with significant associated natural gas, together with increased demand for water transportation and other complementary transportation services, will offer attractive opportunities to expand our gathering footprint and to broaden our service offerings.

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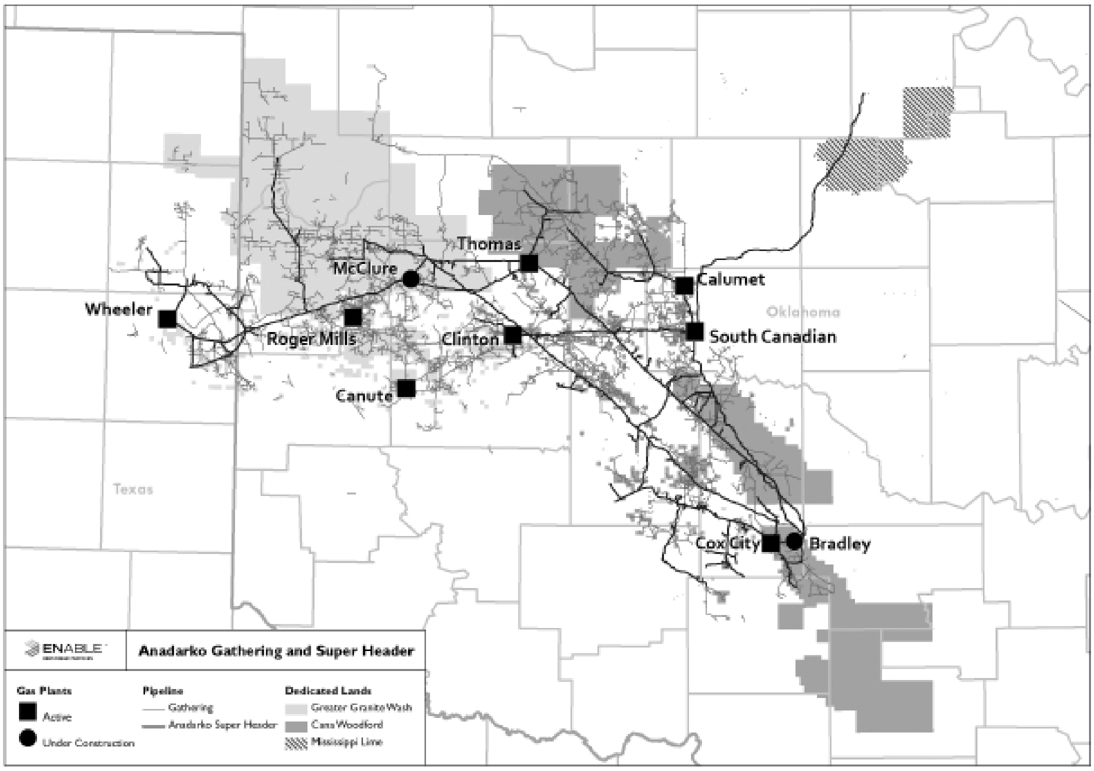
The following is a summary of our recent and planned growth activities by basin:

Anadarko Basin



We are primarily focused on gathering and processing expansions on the west side of our gathering system (Oklahoma and Texas) to support producer drilling, primarily in the Greater Granite Wash area (which includes the Granite Wash, Tonkawa, Marmaton and Cleveland Sands plays), the Cana/Woodford Shale area (which includes the SCOOP) and the Mississippi Lime plays.

We expect that our expansion capital expenditures in the Anadarko basin will be approximately $345 million for the twelve months ending December 31, 2014. We believe we are well-positioned to capture incremental third-party volumes and additional acreage dedications. We have an extensive gathering and processing system coupled with an expansive transportation and storage system that together provides customers with superior access to capacity and pricing for their product.

Greater Granite Wash

We believe drilling in the Greater Granite Wash area will remain robust due to drilling economics in the rich gas plays and the crude oil plays that produce rich associated gas. We expect that our expansion capital expenditures in this area will be approximately $86 million for the twelve months ending December 31, 2014.

To support volume growth in this area we are currently constructing a cryogenic processing plant (the McClure Plant) in Custer County, Oklahoma, which is expected to add 200 MMcf/d of natural gas processing capacity. This plant will be connected to our super-header system and is expected to be in service by the first quarter of 2014.

Cana/Woodford Shale

We believe drilling in the Cana/Woodford Shale area will remain robust due to drilling economics in the rich gas plays and the crude oil plays that produce rich associated gas. We expect that our expansion capital expenditures in this area will be approximately $256 million for the twelve months ending December 31, 2014. To support volume growth in this area we are currently constructing an additional cryogenic processing plant (the Bradley Plant) in Grady County, Oklahoma, which is expected to add 200 MMcf/d of natural gas processing capacity. This plant will be connected to our super-header system and is expected to be in service by the first quarter of 2015.

Mississippi Lime

We recently converted a 65 mile 24-inch pipeline to rich gas gathering service, which connects the Mississippi Lime area to our super-header system. We expect that our expansion capital expenditures in this area will be approximately $3 million for the twelve months ending December 31, 2014.

Arkoma Basin

In the Arkoma basin we are primarily focused on the Western Arkoma (rich and lean Woodford) and the Eastern Arkoma (lean Woodford and the Fayetteville shale). We expect that our expansion capital expenditures in the Aroma basin will be approximately $6 million for the twelve months ending December 31, 2014.

Ark-La-Tex Basin

In the Ark-La-Tex basin we are primarily focused on the relatively rich gas areas of the Haynesville, Bossier and Cotton Valley plays. We expect that our expansion capital expenditures in the Ark-La-Tex basin will be approximately $63 million for the twelve months ending December 31, 2014. The Waskom plant is capable of processing approximately 320 MMcf/d of natural gas, and includes NGL railcar loading capabilities. The gathering assets owned by Waskom are capable of gathering approximately 75 MMcf/d of natural gas.

Williston Basin

In November 2013, we commenced initial operations on a new crude oil gathering pipeline system in North Dakota's oil-rich Bakken shale formation, and we expect to place additional related assets in service in 2014. We expect that our expansion capital expenditures in the Williston basin will be $15 million for the twelve months ending December 31, 2014. We provide crude oil gathering service, water transportation and other complementary transportation services over a gathering system in Dunn and McKenzie counties in North Dakota with a capacity of up to 19,500 barrels per day. We believe this project positions us to expand our emerging crude oil gathering business and allow us to compete for additional third-party volumes in the Bakken as well as in other oil-rich shale plays.

Transportation and Storage

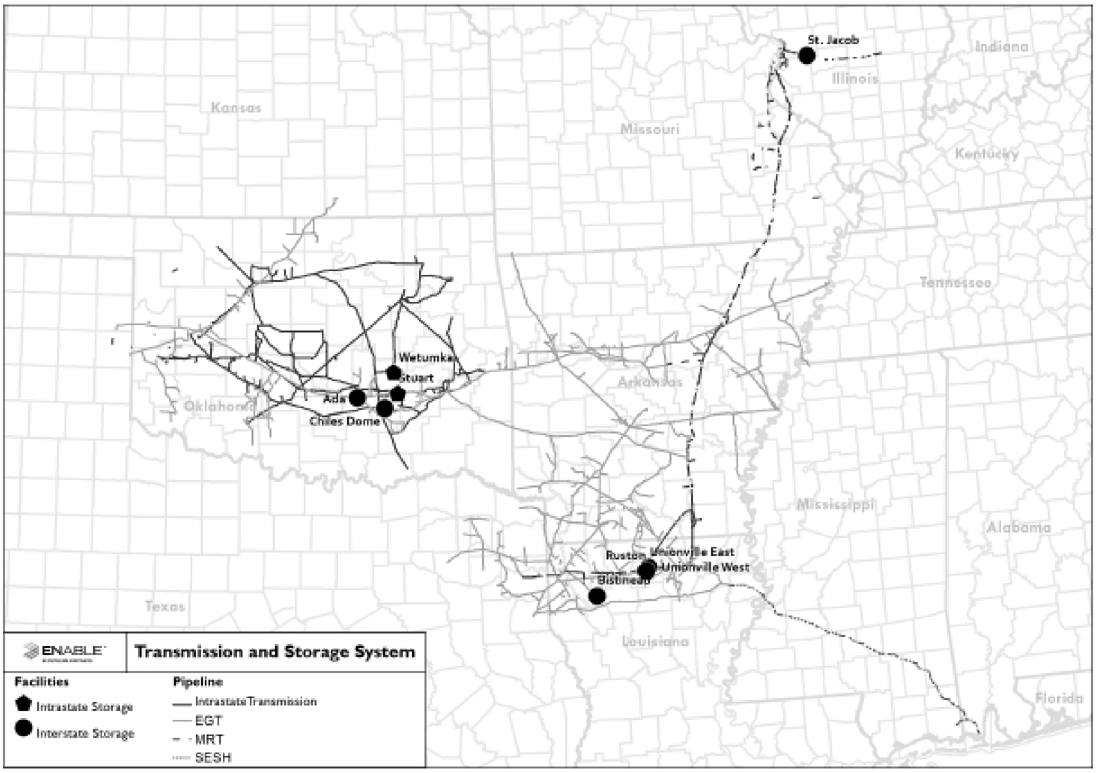
We provide fee-based interstate and intrastate transportation and storage services across nine states. We own and operate approximately 7,800 miles (including SESH) of interstate transportation pipelines with average firm contracted capacity of 7.2 Bcf/d (excluding SESH). for the nine months ended September 30, 2013, on a pro forma basis excluding SESH. In addition, we own and operate approximately 2,300 miles of intrastate transportation pipelines with average aggregate throughput of 1.6 Tbtu/d for the nine months ended September 30, 2013, on a pro forma basis.

We also own and operate eight natural gas storage facilities with approximately 86.5 Bcf of aggregate working gas capacity and approximately 1.9 Bcf/d of aggregate daily deliverability as of September 30, 2013. In addition, we own a 8% contractual interest in Gulf South's Bistineau storage facility located in Bienville Parish, Louisiana, with 8.0 Bcf of working gas and 100 MMcf/d of deliverability as of September 30, 2013. Additionally, we lease 3.5 Bcf of high deliverability salt dome storage capacity from Cardinal in the Perryville and Arcadia natural gas storage fields. Our storage operations are located in Louisiana, Oklahoma and Illinois.

Both our intrastate and interstate storage facilities benefit customers by providing a full suite of storage services including no notice, load-following storage services and pipeline balancing. Our storage revenues are 100% fee-based and are derived from both firm and interruptible contacts. These contracts are often combined with transportation agreements to provide an overall solution for our customers. Our intrastate storage assets offer both fee-based firm and interruptible storage services. Interstate storage services offered by our intrastate storage facilities are provided at market-based rates under Section 311 of the NGPA pursuant to terms and conditions specified in our statements of operating conditions.

We divide our transportation and storage assets into three categories: (1) interstate pipelines, (2) intrastate pipelines, and (3) storage. Our interstate pipelines consist of EGT, MRT and a minority interest in the SESH pipeline. Our intrastate pipelines include the Enable Oklahoma Intrastate Pipelines and the Enable Illinois Intrastate Transmission Company, which is operated commercially in conjunction with MRT.

Our transportation and storage assets were designed and built, and are competitively positioned, to serve large natural gas and electric utility companies in our areas of operation. On a pro forma basis for the nine months ended September 30, 2013, our top customers by gross margin were affiliates of CenterPoint Energy, Laclede, Exxon, OGE Energy and AEP. We are also well positioned to serve other current utility customers such as Ameren and Entergy. Our EGT and MRT pipelines connect to our SESH pipeline in Perryville, Louisiana, where we perform our Perryville Hub™ services, which provides access to Gulf Coast natural gas supplies and to natural gas-consuming markets in the Southeast, Northeast and Midwestern United States.



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Interstate Pipelines

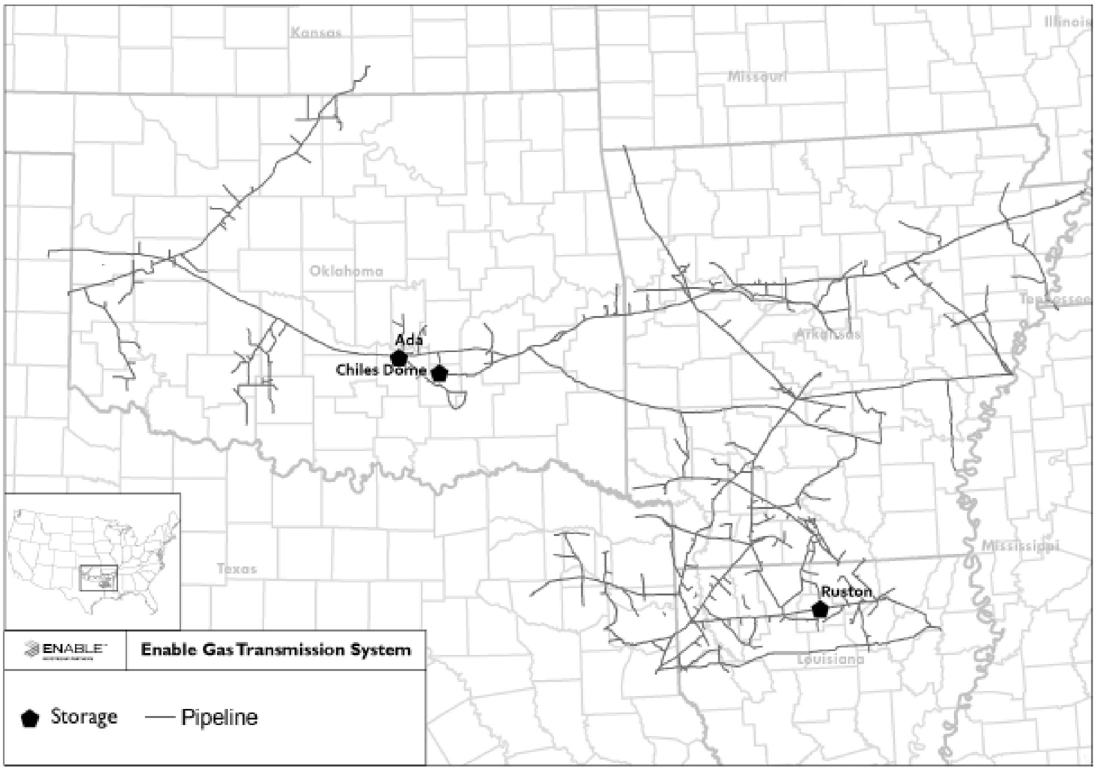
The following table sets forth certain information regarding our interstate pipeline assets as of September 30, 2013:

Interstate Pipelines(1)

Asset	Length (miles)	Compression (Horsepower)	Average Throughput (Tbtu/d)	Capacity (Bcf/d)	Storage Capacity (Bcf)
EGT	5,954	362,591	2.9	6.6	30.5
MRT	1,560	118,912	0.6	1.8	32.0
Total	7,514	481,503	3.5	8.4	62.5

(1) Excludes SESH, which is accounted for as an equity investment and described under "—Other Assets" below.

EGT



General. EGT is a 5,954-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas. The system could transport 6.6 Bcf/d of natural gas as of September 30, 2013. During the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, we transported an average of approximately 2.9 and 3.1 Tbtu/d, respectively, on this system. The system has pipeline diameters ranging from two to 42 inches and has 27 compressor stations. The system also had 30.5 Bcf of working natural gas storage capacity as of September 30, 2013.

Off-System Delivery Points. Shippers on EGT have the ability to access almost every major natural gas-consuming market east of the Mississippi River. These include the growing Southeast power generation sector via SESH, as well as the ANR, SONAT, Tennessee Gas, Texas Gas, Texas Eastern, Gulf South, Trunkline, Columbia Gas and Midcontinent Express (MEP) pipelines, which are interconnected with EGT at Perryville, Louisiana, which includes consuming markets in the Northeast and Midwest United States by utilizing our Perryville Hub™ services.

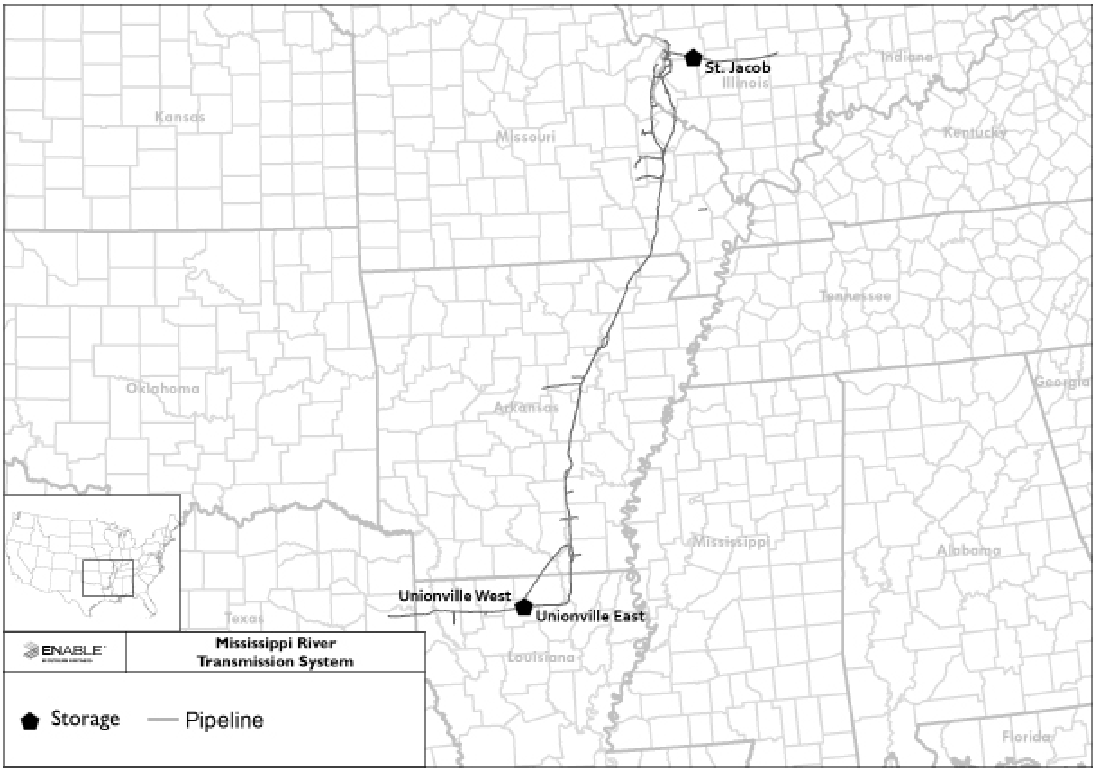
Customers. The primary customers for our EGT system are the local gas distribution divisions of CenterPoint Energy, gas producers who hold contracts for their Barnett and Haynesville shale production, gas-fired power generators and other industrial and local third-party distribution companies. For the twelve months ended December 31, 2012, approximately 24% of EGT's total operating gross margin was attributable to services provided to subsidiaries of CenterPoint Energy. EGT's customers are primarily located in Arkansas, Louisiana, Oklahoma and Texas.

Contracts. EGT's services are typically provided under firm storage and transportation agreements. For each of the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 53% and 52% of total transportation and storage business segment gross margins, respectively, were derived from demand charges under EGT's firm contract arrangements. As of September 30, 2013, approximately 83% of EGT's capacity was under contract with an average remaining contract life of 4.3 years. The primary terms of EGT's firm transportation and storage contracts with CenterPoint Energy will expire in 2018.

EGT established maximum rates for interstate transportation and storage services on its system as required by the FERC, though EGT is authorized to enter into negotiated rate and discounted rate agreements with customers. In October 2012, we initiated a process with EGT's customers to reach an agreed-upon rate, or settlement rate, that will allow us to recover on the increased costs associated with maintaining a safe and reliable system. If an agreement between EGT and its customers is reached, EGT will submit the settlement agreement to FERC for approval. Should these discussions fail, we will consider filing with the FERC for a general rate increase in 2014 in which we will need to support the requested rates in an administrative proceeding. EGT is under no obligation to initiate a rate proceeding by a date certain.

Storage. EGT's storage assets include two underground natural gas storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which operate at a combined working gas level of 30.5 Bcf with 674 MMcf/d of aggregate maximum withdrawal and injection capacity as of September 30, 2013.

MRT



General. MRT is a 1,560-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois. This system provides market access for producers from the Haynesville and Fayetteville shale plays. The system could transport 1.8 Bcf/d of natural gas as of September 30, 2013. During both the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, we transported an average of approximately 0.8 TBtu/d on this system. The system has pipeline diameters ranging from two to 26 inches and has 17 compressor stations. The system also had 32.0 Bcf of working natural gas storage capacity as of September 30, 2013.

Delivery Points. MRT's primary delivery points are to LDCs and industrial markets in the St. Louis market area. MRT's shippers access natural gas at Perryville, Louisiana and East Texas markets and, via EGT interconnects, the Mid-Continent.

Customers. MRT derives a significant portion of its gross margin from an affiliate of Laclede, the local natural gas distribution company serving the St. Louis market area, which comprised 54% of MRT's gross margin for the year ended December 31, 2012, on a pro forma basis. MRT's other customers include subsidiaries of Ameren and subsidiaries of CenterPoint Energy and other industrial companies. MRT's customers are primarily located in Arkansas, Illinois and Missouri.

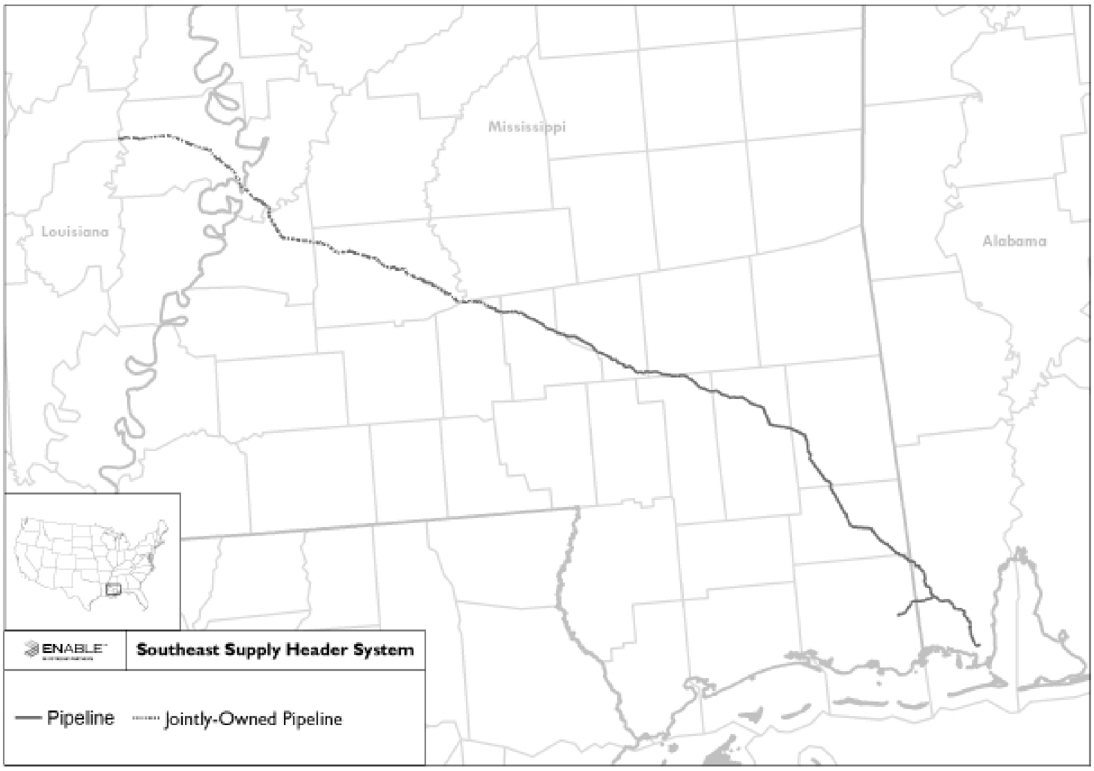
Contracts. MRT's services to its customers are typically provided under firm storage and transportation agreements. For the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, approximately 13% and 12%, respectively, of total transportation and storage business segment gross margins were derived from demand charges under MRT's firm contract arrangements. As of September 30, 2013, approximately 94% of MRT's capacity was under contract with an average remaining contract life of 3.5

years. MRT's firm transportation and storage contracts with Laclede were recently extended and are scheduled to expire in 2015 and 2016.

We made a rate filing with the FERC pursuant to Section 4 of the Natural Gas Act in which we requested an annual cost of service of $104 million (an increase of approximately $47 million above the annual cost of service underlying the current FERC approved maximum rates for MRT's pipeline). On July 30, 2013, MRT filed with the FERC an uncontested Stipulation and Agreement and Offer of Settlement, resolving all issues in the rate case. The settlement specifies few particulars, other than setting an annual overall cost-of-service for MRT of $84 million and increasing the depreciation rates for certain asset classes. In September 2013, the FERC approved the settlement. Although the settlement became effective November 1, 2013, the settlement rates are effective as of March 1, 2013. As a result, MRT will be making refunds to certain of its customers for amounts collected between the requested $104 million cost of service and the $84 million settlement cost of service, which amounts had previously been reserved.

Storage. MRT's storage assets include two underground natural gas storage facilities in Louisiana and one underground natural gas storage facility in Illinois, which operate at a combined working gas level of 32.0 Bcf with 576 MMcf/d of aggregate maximum withdrawal and injection capacity as of September 30, 2013.

Other Assets



SESH is a 274-mile interstate pipeline that provides natural gas transportation and pipeline services. We own a 24.95% interest in SESH and operate the pipeline. We have the ability to acquire CenterPoint Energy's remaining 25.05% of SESH by 2015. Please read "Certain Relationships and Related Party Transactions—Master Formation Agreement—Acquisition of Remaining CenterPoint Energy Interest in SESH." The remaining 50% of

SESH is owned by affiliates of Spectra Energy Corp, who are responsible for the pipeline's back office and marketing operations.

The SESH pipeline runs from Perryville, Louisiana to southeastern Alabama near the Gulf Coast, where most of the gas transported by the pipeline is transported by third-party pipelines to companies generating electricity for the Florida power market. As of September 30, 2013, the system could transport 1.5 Bcf/d of natural gas from Perryville to Gwinville, Mississippi, and 1.0 Bcf/d of natural gas to the pipeline's end point in Alabama. During the nine months ended September 30, 2013 and the year ended December 31, 2012, on a pro forma basis, an average of approximately 0.9 Bcf/d and 1.0 Bcf/d, respectively, was transported on this system. The system has pipeline diameters ranging from 16 to 42 inches and has 3 compressor stations.

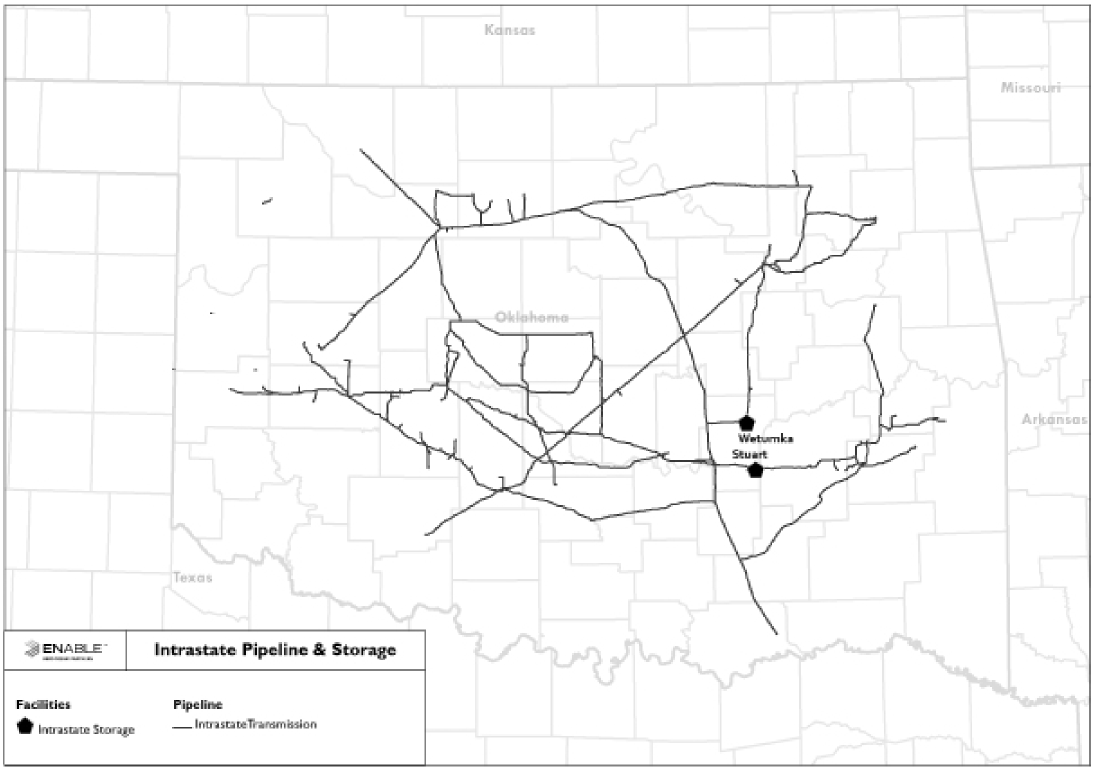
The SESH pipeline has 11 interconnections with existing natural gas pipelines and access to three high deliverability storage facilities: Mississippi Hub Storage, Petal Gas Storage and Southern Pines Energy Center.

The primary customers for the SESH pipeline are companies that generate electricity using natural gas in the Florida market area. The rates charged by SESH for interstate transportation services are regulated by the FERC. Service on SESH is largely provided under long-term, negotiated rate agreements with customers.

Competition

Our interstate pipelines compete with other interstate and intrastate pipelines. The principal elements of competition among pipelines are rates, terms of service, and flexibility and reliability of service.

Intrastate Pipelines



General. Our intrastate pipelines consist of approximately 2,300 miles of intrastate transportation pipeline system in Oklahoma with 1.6 Tbtu/d of average daily throughput for the twelve months ended December 31, 2012 on a pro forma basis and approximately 20 miles of intrastate transportation pipeline in Illinois. Our intrastate systems deliver natural gas to interstate and intrastate pipelines and end users primarily connected to the systems from the Arkoma and Anadarko basins, including growth activity in the Cana Woodford, Granite Wash, Cleveland, Tonkawa, SCOOP and Mississippi Lime shale plays in western Oklahoma and the Texas Panhandle.

Delivery Points. Our intrastate pipelines are connected to our EGT system and 12 third-party natural gas pipelines and have 62 interconnect points. These third-party natural gas pipelines include ANR Pipeline, El Paso Natural Gas Pipeline, Gulf Crossing Pipeline Company LLC, MEP, Natural Gas Pipeline Company of America, Northern Natural Gas Company, ONEOK Gas Transmission, Ozark Gas Transmission, L.L.C., Panhandle Eastern Pipe Line, Postrock KPC Pipeline, LLC, Southern Star Central Gas Pipeline (formerly Williams Central) and Western Farmers Electric Cooperative. In addition, our intrastate pipelines are connected to 36 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

Customers. Our major transportation customers are OG&E, our affiliate, and Public Service Company of Oklahoma, an affiliate of AEP (PSO), the two largest electric utilities in Oklahoma. We provide gas transmission delivery services to all of OG&E's and PSO's natural gas-fired electric generation facilities in Oklahoma under firm intrastate transportation contracts. Customer demand for natural gas on our system is usually greater during the summer, primarily due to demand by natural gas-fired electric generation facilities to serve residential and commercial electricity requirements.

Contracts. The intrastate pipelines provide fee-based firm and interruptible transportation services on both an intrastate basis and, pursuant to Section 311 of the NGPA, on an interstate basis. Transportation services are offered under Section 311 of the NGPA pursuant to terms and conditions specified in our statement of operating conditions for natural gas transportation. We derive a substantial portion of our transportation gross margins from firm transportation services subject to reservation charges. To the extent pipeline capacity is not needed for such firm transportation services and contracted capacity, we offer interruptible transportation services.

For the nine months ended September 30, 2013, on a pro forma basis, approximately 17% of our total transportation and storage business segment gross margins were derived from demand charges under firm contract arrangements for our intrastate pipelines. Our contracts with PSO and OG&E provide for a monthly demand charge plus variable transportation charges including fuel. The stated term of the PSO contract expired January 1, 2013, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least six months prior to the commencement of the succeeding annual period. Because neither party provided notice of termination six months prior to January 1, 2014, the PSO contract will remain in effect at least through January 1, 2015. The stated term of the OG&E contract expired April 30, 2009, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 90 days prior to the commencement of the succeeding annual period. As part of the no-notice load-following contract with OG&E, we provide natural gas storage services for OG&E. We have been providing natural gas storage services to OG&E since August 2002 when we acquired the Stuart Storage Facility located in Hughes County, Oklahoma.

Storage. Our intrastate storage assets include two underground natural gas storage facilities in Oklahoma, which operate at a combined working gas level of 24 Bcf with 650 MMcf/d of aggregate maximum withdrawal and injection capacity as of September 30, 2013.

Competition

Our intrastate pipeline system competes with numerous interstate and intrastate pipelines, including several of the interconnected pipelines discussed above, and storage facilities in providing transportation services for natural gas. The principal elements of competition are rates, terms of services, flexibility and reliability of service. Natural gas-fired electric generation facilities contribute their highest value when they have the capability to provide load following service to the customer (*i.e.*, the ability of the generation facility to regulate generation to respond to and meet the instantaneous changes in customer demand for electricity). While the physical characteristics of natural gas-fired electric generation facilities are known to provide quick start-up, on-line functionality and the ability to efficiently provide varying levels of electric generation relative to other forms of generation, a key part of their effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond quickly to meet their corresponding fluctuating fuel needs. We believe that we are well positioned to compete for the needs of these generators due to the ability of our transportation and storage assets to provide no-notice load following service.

Growth Opportunities for Transportation and Storage Business Segment

Our transportation systems are well-positioned to grow as environmental concerns drive the conversion of more coal-fired power generation to natural gas. We believe our system is also well-positioned to transport additional volumes of natural gas as regional premiums to benchmark prices, known as basis spreads, become more favorable. In addition, we expect the significant growth in the Oklahoma producing areas will provide growth opportunities for our entire transportation and storage systems as producers look for options to deliver their natural gas to market. The Perryville Hub is an integral part of our customer service offerings and provides a pathway to the important southeast power generation and industrial markets as well as the high-demand northeast markets.

Over the past several years, we have initiated multiple organic growth projects to increase capacity across our system, including expansions related to our expanding gathering and processing operations.

We believe that throughput on our EGT system will continue to grow due to increasing production in rich gas plays such as the Cana Woodford, Granite Wash, Mississippi Lime and East Texas/Cotton Valley plays. In 2014, we plan to invest $18 million of expansion capital in order to construct additional pipeline laterals to this system to accommodate this increasing production.

Since 2004, we have invested approximately $582 million on the SESH pipeline. We believe that throughput on the SESH pipeline will continue to grow due to increasing demand for natural gas across the southeastern United States. In order to expand throughput, we expect to spend approximately $6 million on growth projects through December 31, 2014, which we expect to place into service in the second half of 2014. This amount represents our share of the forecasted expansion capital for the joint venture.

Rate and Other Regulation

Federal, state, and local regulation of pipeline gathering and transportation services may affect certain aspects of our business and the market for our products and services.

Interstate Natural Gas Pipeline Regulation

Our interstate pipeline systems—EGT, MRT, and SESH—are subject to regulation by FERC under the NGA and are considered natural gas companies. Natural gas companies may not charge rates that have been determined to be unjust or unreasonable by the FERC. In addition, the FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities or expansion of existing facilities;
- extension or abandonment of services and facilities;

- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate natural gas sales, purchases or transportation; and
- various other matters.

Under the NGA, the rates for service on interstate facilities must be just and reasonable and not unduly discriminatory. Generally, the maximum filed recourse rates for interstate pipelines are based on the pipeline's cost of service including recovery of and a return on the pipeline's actual prudent investment cost. Key determinants in the ratemaking process are costs of providing service, allowed rate of return, volume throughput and contractual capacity commitment assumptions. Our interstate pipelines business operations may be affected by changes in the demand for natural gas, the available supply and relative price of natural gas in the Mid-continent and Gulf Coast natural gas supply regions and general economic conditions.

Tariff changes can only be implemented upon approval by the FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with the FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. FERC will provide notice to the public through publication of the notice in the Federal Register. If the FERC determines that a proposed change is just and reasonable, the FERC will accept the proposed change and the pipeline will implement such a change in its tariff, normally 30 days after filing. However, if the FERC determines that a proposed change may not be just and reasonable then the FERC may suspend such a change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by the FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, the FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If the FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

Market Behavior Rules; Posting and Reporting Requirements

On August 8, 2005, Congress enacted the EPAct of 2005. Among other matters, the EPAct of 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 regulation 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 provisions of the EPAct of 2005. 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 not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The 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 anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering to the extent such transactions do not have a “nexus” to jurisdictional transactions. The EPAct of 2005 also amends the NGA and the NGPA to give the FERC authority to impose civil penalties for violations of these statutes and FERC’s regulations, rules, and orders, up to $1 million per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, the FERC issued a revised 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, rules, regulations and orders, we could be subject to substantial penalties and fines. In addition, the CFTC is directed under the Commodities Exchange Act, or CEA, to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act and other authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1 million or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA.

The EPAct of 2005 also added 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 order 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 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 information 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 FERC’s periodic review of the rates charged by the subject pipelines from three to five years. Order No. 735 became effective on April 1, 2011. In December 2010, the FERC issued Order No. 735-A. In Order No. 735-A, the FERC 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.

On November 15, 2012, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether to amend its regulations under the natural gas market transparency provisions of Section 23 of the NGA, as adopted by EPAct of 2005, to consider the extent to which quarterly reporting of every natural gas transaction within the FERC’s NGA jurisdiction that entails physical delivery for the next day or next month would provide useful information for improving natural gas market transparency. On July 9, 2013, the FERC provided notice that it was making a data request of certain natural gas marketers to better assess the reporting requirements. FERC has not yet issued an order.

Intrastate Natural Gas Pipeline and Storage Regulation

Our transmission lines are subject to state regulation of rates and terms of service. In Oklahoma, our intrastate pipeline system is subject to regulation by the Oklahoma Corporation Commission, or the OCC. Oklahoma has a non-discriminatory access requirement, which is subject to a complaint-based review. In Illinois, our intrastate pipeline system is subject to regulation by the Illinois Commerce Commission.

Intrastate natural gas transportation is largely regulated by the state in which the transportation takes place. An intrastate natural gas pipeline system may transport natural gas in interstate commerce provided that the rates, terms, and conditions of such transportation service comply with FERC regulation and Section 311 of the NGPA and Part 284 of the FERC's regulations. The NGPA regulates, among other things, the provision of transportation and storage services by an intrastate natural gas pipeline on behalf of an interstate natural gas pipeline or a LDC served by an interstate natural gas pipeline. Under Section 311, rates charged for 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 are maximum rates and we may negotiate contractual rates at or below such maximum rates. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. 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 services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, or failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the assertion of federal NGA jurisdiction by FERC and/or the imposition of administrative, civil and criminal penalties, as described in the "—Interstate Natural Gas Pipeline Regulation" section above.

The transportation rates charged by Enable Oklahoma Intrastate Transmission, LLC for natural gas transportation in interstate commerce on intrastate pipelines are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Enable Oklahoma currently has two zones under its Section 311 transportation rate structure—an East Zone and a West Zone. Enable Oklahoma historically offered only interruptible Section 311 service in both zones. Enable Oklahoma began to offer firm Section 311 service in the East Zone on April 1, 2009 and in the West Zone on March 1, 2011. For Section 311 service, Enable Oklahoma may charge up to its maximum established zonal East and West interruptible transportation rates for interruptible transportation in one zone or cumulative maximum rates for transportation in both zones. Enable Oklahoma may charge up to its maximum established firm rate for firm Section 311 transportation in its East and West Zones. Finally, Enable Oklahoma may charge the applicable fixed zonal fuel percentage(s) for the fuel used in transporting natural gas under Section 311 on our system. The fuel percentages are the same for firm and interruptible Section 311 services.

We also have a pipeline in Illinois that is subject to regulation by the Illinois Commerce Commission as a so-called "Hinshaw pipeline." Under Section 1(c) of the NGA, a Hinshaw pipeline is exempt from FERC's NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission. A Hinshaw pipeline may, and our Illinois pipeline does, provide services in interstate commerce pursuant to limited jurisdiction certificate authority under Section 284.224(c) of FERC's regulations, thereby subjecting itself to the same type of limited FERC jurisdiction imposed on intrastate pipelines engaged in Section 311 service.

Our intrastate storage assets at the Wetumka Storage Field offer both fee-based firm and interruptible storage services under Section 311 of the NGPA pursuant to terms and conditions specified in our statement of operating conditions for gas storage at market-based rates. Our intrastate Stuart Storage Field currently is used exclusively to provide intrastate storage service, even though FERC previously authorized the use of that storage facility for Section 311 interstate service.

Natural Gas Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. Although the FERC has not made formal determinations with respect to all of our facilities we consider to be gathering facilities, 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 is subject to change based on future determinations by the FERC, the courts or Congress. 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 and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the rate established by the FERC.

States may regulate gathering pipelines. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, requirements prohibiting undue discrimination, and in some instances complaint-based rate regulation. Our gathering operations may be subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase 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. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Oklahoma and Texas have each adopted a form of complaint-based regulation of gathering operations that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering open access and rate discrimination. Texas has also adopted a complaint based regulation, known as the lost and unaccounted for gas bill, which gives the Texas Railroad Commission the authority to issue orders for purposes of preventing waste in specific situations. To date, neither the gathering regulations nor the lost and unaccounted for gas bill have had a significant impact on our operations in Oklahoma or Texas. However, we cannot predict what effect, if any, either of these regulations might have on its gathering operations in Oklahoma or Texas in the future.

Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations could also be subject to additional safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance 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 its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Sales of Natural Gas

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

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

Crude Oil Gathering Regulation

Crude oil gathering pipelines that provide interstate transportation service may be regulated as a common carrier by the FERC under the ICA, the Energy Policy Act of 1992, and the rules and regulations promulgated under those laws. The ICA and FERC regulations require that rates for interstate service pipelines that transport crude oil and refined petroleum products (collectively referred to as "petroleum pipelines") and certain other liquids, be just and reasonable and are to be non-discriminatory or not confer any undue preference upon any shipper. FERC regulations also require interstate common carrier petroleum pipelines to file with the FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service. Under the ICA, the FERC or interested persons may challenge existing or changed rates or services. The FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. A successful rate challenge could result in a common carrier paying refunds together with interest for the period that the rate was in effect. The FERC may also order a pipeline to change its rates, and may require a common carrier to pay shippers reparations for damages sustained for a period up to two years prior to the filing of a complaint.

If our rate levels were investigated by the FERC, the inquiry could result in a comparison of our rates to those charged by others or to an investigation of our costs, including:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the regulated entity;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity and interest rates on debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

For some time now, the FERC has been issuing regulatory assurances that necessarily balance the anti-discrimination and undue preference requirements of common carriage with the expectations of investors in new and expanding petroleum pipelines. There is an inherent tension between the requirements imposed upon a common carrier and the need for owners of petroleum pipelines to be able to enter into long-term, firm contracts with shippers willing to make the commitments which underpin such large capital investments. For example, the FERC has found that shipper contract rates are not per se violations of the duty of non-discrimination, provided that such rates are available to all similarly-situated shippers. In the same vein, the FERC has approved varying term commitments with tiered rate discounts on the basis that committed shippers were not similarly situated with uncommitted shippers and further that different types of committed shippers were not similarly situated with each other if their commitment level materially differed. The FERC has also found that shippers making certain commitments to the pipeline can take advantage of priority or firm service, which is service that is not subject to typical capacity allocation requirements, so long as any interested shipper has an equal opportunity to make such a commitment to the carrier. The FERC's solution has been to allow carriers to hold an "open season" prior to the in-service date of pipeline, during which time interested shippers can make commitments to the proposed pipeline project. Throughput commitments from interested shippers during an open season can be for firm service or for non-firm service. Typically, such an open season is for a 30-day period, must be publicly announced, and culminates in interested parties entering into transportation agreements with the carrier. Under FERC precedent, a carrier typically may reserve up to 90% of available capacity for the provision of firm service to shippers making a commitment. At least 10% of capacity ordinarily is reserved for "walk-up" shippers.

Under the ICA, the FERC does not have authority over the siting of oil transportation assets nor over the abandonment of facilities or services. Accordingly, no approval from the FERC is necessary prior to placing a new petroleum pipeline project in operation. However, the FERC highly encourages carriers to file a Petition for Declaratory Order (PDO) to seek regulatory assurances for key terms of service offered during an open season. As long as the shippers on our Bakken crude oil gathering system move oil in interstate commerce, our crude oil gathering system will not be regulated by the North Dakota Public Service Commission.

Safety and Health Regulation

Certain of our facilities are subject to pipeline safety regulations. PHMSA regulates safety requirements in the design, construction, operation and maintenance of jurisdictional natural gas and hazardous liquid pipeline facilities. All natural gas transmission facilities, such as our interstate natural gas pipelines, are subject to PHMSA's pipeline safety regulations, but natural gas gathering pipelines are subject to the pipeline safety regulations only to the extent they are classified as regulated gathering pipelines. In addition, several NGL pipeline facilities and crude oil pipeline facilities are regulated as hazardous liquids pipelines. Currently, each such NGL or crude oil facility is excepted from many of the requirements of PHMSA's regulations applicable to hazardous liquids pipelines based on the facility's location, product transported, and/or the low stress level at which it operates.

Pursuant to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Hazardous Liquid Pipeline Safety Act of 1979, or HLPSA, as amended by the Pipeline Safety Act of 1992, or PSA, the Accountable Pipeline Safety and Partnership Act of 1996, or APSA, the Pipeline Safety Improvement Act of 2002, or PSIA, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or the PIPES Act, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the 2011 Pipeline Safety Act, the DOT, through PHMSA, regulates pipeline safety and integrity. 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, or HCAs.

NGL and crude oil pipelines are subject to regulation by PHMSA under the HLPSA which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations. The PSA added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the APSA, which limited the operator identification requirement to operators of pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management.

PHMSA has developed regulations that require natural gas pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

Although many of our pipeline facilities fall within a class that is currently not subject to these integrity management requirements, we may incur significant costs and liabilities associated with repair, remediation, preventive or mitigating measures associated with our non-exempt pipelines. In 2012, we incurred $32 million of capital expenditures and operating costs for pipeline integrity management. We currently estimate that we will incur capital expenditures and operating costs of between $425 million and $450 million from 2013 to 2017 in connection with pipeline integrity management to complete the testing required by existing DOT regulations and their state counterparts. The estimated capital expenditures and operating costs include our estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary. At this time, we cannot predict the ultimate costs of our integrity management program and compliance with these regulations because those costs will depend on the number and extent of any repairs found to be necessary and the degree to which newly proposed pipeline safety regulations may apply to our pipeline systems. We will continue to assess, remediate and maintain the integrity of our pipelines. The results of these activities could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of our pipelines. 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 managements program to currently unregulated pipelines, including gathering lines, our costs associated with compliance may have a material effect on our operations.

The 2011 Pipeline Safety Act 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 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in HCAs. Effective October 25, 2013, PHMSA adopted new rules increasing the maximum administrative civil penalties for violations of the pipeline safety laws and regulations after January 3, 2012 to $0.2 million per violation per day, with a maximum of $2 million for a related series of violations. 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. PHMSA also published advance notice of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including changes to those rules that would apply to gathering lines and removal of an exemption for natural gas pipelines installed before 1970. In May 2012, PHMSA published an advisory bulletin stating that operators of gas and hazardous liquid pipeline facilities should verify records relating to operating specifications for maximum allowable operating pressure, MAOP, for gas pipelines and maximum operating pressure, or MOP, for hazardous liquid pipelines. For natural gas transmission pipelines located within Class 3 and Class 4 locations or in Class 1 and Class 2 locations in HCAs, PHMSA modified its annual report form to require operators to report the number of verified miles of pipeline on their systems. This report was due and filed in June 2013. No MOP reporting requirements were imposed on operators of hazardous liquid pipeline for the 2012 calendar year reports. Our current practice is to continually monitor and update our records with respect to MAOP of our gas pipelines. Future PHMSA rulemakings and/or industry commitments could have a material impact on our operations.

While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly through more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes will provide sufficient time to come into compliance with the new requirements, the costs associated with compliance may have a material effect on our operations.

States are preempted by federal law from imposing pipeline safety standards below the minimum federal standards established by DOT, but they may establish more rigorous standards for intrastate gas and hazardous liquids pipelines. State agencies may also assume responsibility for enforcing intrastate pipeline regulations as a cooperating agency. In practice, states vary considerably in their authority and capacity to address pipeline safety. In the state of Oklahoma, the OCC's Transportation Division, acting through the Pipeline Safety Department, administers the OCC's intrastate regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. The OCC develops regulations and other approaches to assure safety in design, construction, testing, operation, maintenance and emergency response to pipeline facilities. The OCC derives its authority over intrastate pipeline operations through state statutes and certification agreements with the DOT. A similar regime for safety regulation is in place in Texas and is administered by the Texas Railroad Commission. Our natural gas transmission and DOT regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We have incorporated all existing requirements into our programs by the required regulatory deadlines, and are continually incorporating the new requirements into procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and forecasted changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity transported by our system, or a regulatory inspection identifies a deficiency in our required programs.

In addition to these pipeline safety requirements, we are subject to a number of federal and state laws and regulations, including the Occupational Safety and Health Act of 1970 (OSHA) and comparable state statutes, whose purpose is to protect the safety and health of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the 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 this information be provided to employees, state and local government authorities and citizens. We 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. We have an internal program of inspection designed to monitor and enforce compliance with worker safety and health requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker safety and health.

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.

While we are not currently subject to governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered by the U.S. Congress and by U.S. Executive Branch departments and agencies, including the Department of Homeland Security, and we may become subject to such standards in the future. We have systems in place to monitor and address the risk of cyber-security breaches in our business, operations and control environments. We routinely review and update those systems as the nature of that risk requires. We are not aware of any cyber-security breach affecting any of our business, operations or control environments. A significant cyber-attack could have a material effect on our operations and those of our customers.

Environmental Matters

General

Our activities are subject to stringent and complex federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact our business activities in many ways, such as restricting the way we can handle or dispose of our wastes, requiring remedial action to mitigate pollution conditions that may be caused by our operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. We believe that our operations are in substantial compliance with current federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of our facilities and has the potential to restrict or delay our operations and development projects, particularly pipeline projects. Historically, our total expenditures for environmental control measures and for remediation have not been significant in relation to our consolidated financial position or results of operations. We believe, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

We estimate that our routine environmental expenses for 2013 for technical support, fees, sampling, testing and other similar items will be $10 million. Reciprocating internal combustion engines maximum achievable control technology (RICE MACT) and greenhouse gases (GHG) expenses for 2013 are estimated to be $4 million. Routine expenses for 2014 to 2016 are expected to average $10 million per year, and RICE MACT and GHG costs are expected to average $3 million per year over the same timeframe. Costs for incidental environmental activities, such as permitting as part capital projects and waste disposal, are included in routine capital and operating expenses. Management continues to evaluate our compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Air

Our operations are subject to the federal Clean Air Act, as amended (CAA), and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions (including greenhouse gas emissions as discussed below), obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Climate Change

More stringent laws and regulations relating to climate change and GHGs may be adopted in the future and could cause us to incur material expenses in complying with them. Both houses of Congress have actively considered legislation to reduce emissions of GHGs, but no legislation has passed. In the absence of comprehensive federal legislation on GHG emission control, the EPA has adopted rules under the CAA to regulate GHGs as pollutants under the CAA. The EPA has adopted the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule), which phases in permitting requirements for stationary sources of GHGs, beginning January 2, 2011. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Our operations are subject to these permitting requirements, and if additional changes or other similar requirements are enacted, our facilities could be subject to significant additional costs to control our emissions and comply with regulatory requirements. Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Oklahoma, Arkansas, Louisiana, Kansas, Missouri, Illinois, Tennessee, Mississippi, Alabama, North Dakota and Texas are not among them. If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of carbon dioxide and other GHGs on our facilities, this could result in significant additional compliance costs that would affect the our future financial position, results of operations and cash flows.

In 2009, the EPA adopted a comprehensive national system for reporting emissions of carbon dioxide and other GHGs produced by major sources in the United States known as the Greenhouse Gas Mandatory Reporting Rule. The reporting requirements apply to large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year which included certain of our facilities. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in 2009 to include natural gas processing, transmission, storage and distribution activities. Beginning in September of 2012 with 2011 data, certain midstream facilities are now required to submit annual reports of GHG emissions to the EPA.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas we gather, treat and transport. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

National Environmental Policy Act (NEPA)

NEPA provides for regulatory review in connection with certain projects that involve federal lands or require certain actions by federal agencies, which implicates a number of other laws and regulations such as the Endangered Species Act, Migratory Bird Treaty Act, Rivers and Harbors Act, Clean Water Act, Bald and Golden

Eagle Protection Act, Fish and Wildlife Coordination Act, Marine Mammal Protection Act and National Historic Preservation Act. The NEPA review process can be lengthy and subjective and can cause delays in projects. Some of our projects that require NEPA review are related to pipeline integrity. Ineffective implementation of this process could cause significant impacts to commercial and compliance projects.

Endangered Species

Certain federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the Endangered Species Act, or ESA, by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our customer's exploration and production activities that could have an adverse impact on demand for our services. Portions of the basins we serve are designated as critical or suitable habitat for endangered species. If additional portions of the basins we serve were designated as critical or suitable habitat for endangered species, it could aversely impact the cost of operating our systems and of constructing new facilities. We believe that we are in substantial compliance with all applicable laws providing special protection to designated species.

Hazardous Substances and Waste

Our operations are subject to federal and state environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. For instance, our operations are subject to the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA or Superfund) and comparable state cleanup laws that impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Because we utilize various products and generate wastes that are considered hazardous substances for purposes of CERCLA, we could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to us.

Our operations also generate solid and hazardous wastes that are subject to the federal Resource Conservation and Recovery Act of 1976 (RCRA) as well as comparable state laws. While RCRA regulates both solid and hazardous wastes, it imposes detailed requirements for the handling, storage, treatment and disposal of hazardous waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as 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. Such changes to the law could have an impact on our capital expenditures and operating expenses. Further, these RCRA-exempt oil and gas exploration and production wastes may still be regulated under state law or RCRA's less stringent solid waste requirements. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or a comparable state law regime.

Water

Our operations are subject to the federal Clean Water Act and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. In addition, the federal 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 some of our facilities. The federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with many of these requirements.

The primary federal law related to oil spill liability is the Oil Pollution Act (the OPA) which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and a small percentage of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is regulated by state agencies, typically the state's oil and gas commission. A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for our customers to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the volume of natural gas that our customers produce, and could thereby adversely affect our revenues and results of operations.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 10 to Notes to Combined Financial Statements.

Employees

As of September 30, 2013, approximately 1,900 individuals were providing services to us as seconded employees by OGE Energy and CenterPoint Energy, and other individuals were providing services to us pursuant to services agreements with OGE Energy or CenterPoint Energy. We did not have any direct employees. Please read "Certain Relationships and Related Party Transactions—Employee Agreements" for a description of the agreements governing these relationships.

Properties

Our real property falls into two categories: (i) parcels that we own in fee and (ii) 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. Certain of our processing plants and related facilities are located on land we own in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plants and related facilities are located is held by us pursuant to ground leases between us, or our subsidiaries, as lessee, and the fee owner of the lands, as lessors. We, or our predecessors, have leased 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 to 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.

Record title to some of our assets may reflect names of prior owners until we have made the appropriate filings in the jurisdictions in which such assets are located. Title to some of our assets may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of our properties or our interest in those properties or should materially interfere with our use of them in the operation of our business. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent owners of record of the properties. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the rights-of-way grants.

We currently occupy 134,219 square feet of office space at One Leadership Square, 211 North Robinson Avenue, Suite 950, Oklahoma City, Oklahoma 73102 under a lease that expires March 31, 2017. Although we may require additional office space as our business expands, we believe that our current facilities are adequate to meet our needs for the immediate future. In addition to our executive offices, we own numerous facilities throughout our service territory that support our operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, compressor station facilities, operation support and other properties.

During the three years ended December 31, 2012, on a pro forma basis, our gross property, plant and equipment (excluding construction work in progress) additions were $3 billion and gross retirements were $212 million (including assets held for sale of $26 million). These additions were provided by cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper), long-term borrowings and permanent financings. The additions during this three-year period amounted to 37% of gross property, plant and equipment (excluding construction work in progress) at December 31, 2012.

Legal Proceedings

In the normal course of business, we are confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, we have incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in our Consolidated Financial Statements. At the present time, based on currently available information, we believe that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to our financial statements and would not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

MANAGEMENT

Management of Enable Midstream Partners, LP

Our general partner will manage our operations and activities on our behalf through its directors and officers. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. The directors of our general partner will oversee our operations. Unitholders will not be entitled to elect the directors of our general partner, who will all be appointed by OGE Energy and CenterPoint Energy, or directly or indirectly participate in our management or operations. However, our general partner owes a duty to our unitholders. 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 expressly non-recourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are non-recourse to it.

The board of directors of our general partner is comprised of four directors. We intend to increase the size of the board of directors to seven members upon the completion of this offering. We intend to further increase the size of the board of directors to eight directors within twelve months of the date of this prospectus. OGE Energy and CenterPoint Energy have each appointed two members to the board of directors of our general partner, and our President and Chief Executive Officer will join the board upon the completion of this offering. The remaining directors will be chosen by unanimous vote of OGE Energy and CenterPoint Energy. When the size of the board increases to seven directors, we will have two directors who are independent as defined under the independence standards established by the NYSE. When the size of the board increases to eight directors, we will have three directors who are independent under such standards. The NYSE does not require a publicly traded limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation or a nominating and corporate governance committee. We are, however, required to have an audit committee of at least three members who meet the independence and experience tests established by the NYSE and the Exchange Act within twelve months of the date our common units are first traded on the NYSE.

In compliance with the requirements of the NYSE, prior to the closing of this offering, OGE Energy and CenterPoint Energy will have appointed two independent members to the board of directors of our general partner. OGE Energy and CenterPoint Energy will appoint a third independent director within twelve months of the date of this prospectus. Independent members of the board of directors of our general partner will serve as the initial members of the audit and the conflicts committees of the board of directors of our general partner.

In identifying and evaluating candidates as possible director-nominees of our general partner, OGE Energy and CenterPoint Energy will assess the experience and personal characteristics of the possible nominee against the following individual qualifications, which OGE Energy and CenterPoint Energy may modify from time to time:

- possesses appropriate skills and professional experience;
- has a reputation for integrity and other qualities;
- possesses expertise, including industry knowledge, determined in the context of the needs of the board of directors of our general partner;
- has experience in positions with a high degree of responsibility;
- is a leader in the organizations with which he or she is affiliated;
- is diverse in terms of geography, gender, ethnicity and age;
- has the time, energy, interest and willingness to serve as a member of the board of directors of our general partner; and
- meets such standards of independence and financial knowledge as may be required or desirable.

The officers of our general partner will manage the day-to-day affairs of our business. We will also utilize a significant number of employees of OGE Energy and CenterPoint Energy to operate our business and provide us with general and administrative services pursuant to seconding agreements and services agreements. Please see "Certain Relationships and Related Party Transactions."

Directors and Executive Officers of Enable GP, LLC

The following table shows information regarding the current directors and executive officers of Enable GP, LLC. Directors are elected for one-year terms. The business address of each of the directors and officers is listed below.

Name	Age	Position with Enable GP, LLC
Scott M. Prochazka(1)	47	Director and Interim Chairman
Gary L. Whitlock(1)	64	Director
Peter B. Delaney(2)	59	Director
Sean Trauschke(2)	46	Director
Lynn L. Bourdon, III	51	Director Nominee and President and Chief Executive Officer(4)
Stephen E. Merrill(3)	49	Executive Vice President of Finance and Chief Administrative Officer
E. Keith Mitchell(3)	51	Chief Operating Officer
Mark C. Schroeder(1)	57	General Counsel

(1) 1111 Louisiana Street, Houston, Texas 77002
(2) 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101
(3) One Leadership Square, 211 North Robinson Avenue, Suite 950, Oklahoma City, Oklahoma 73102
(4) Mr. Bourdon was appointed as President and Chief Executive Officer of our general partner effective February 1, 2014. Mr. Bourdon will assume a position on the board of directors of our general partner upon completion of this offering.

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors of our general partner. There are no family relationships among any of our directors or executive officers.

Scott M. Prochazka has been a director of our general partner since November 2013. Mr. Prochazka has served as Executive Vice President and Chief Operating Officer of CenterPoint Energy since August 1, 2012. He previously served as Senior Vice President and Division President, Electric Operations of CenterPoint Energy from May 2011 through July 2012; as Division Senior Vice President, Electric Operations of CenterPoint Energy's wholly owned subsidiary, CenterPoint Energy Houston Electric, LLC, from February 2009 to May 2011; as Division Senior Vice President Regional Operations of CenterPoint Energy's wholly owned subsidiary, CenterPoint Energy Resources Corp., from February 2008 to February 2009; and as Division Vice President, Customer Service Operations, from October 2006 to February 2008. We believe Mr. Prochazka's extensive knowledge of the industry and us, our operations and people, gained in his years of service with CenterPoint Energy in positions of increasing responsibility provides the board with valuable experience.

Gary L. Whitlock has been a director of our general partner since May 2013. From May 1, 2013 to December 11, 2013, he served as Acting Chief Financial Officer of our general partner. He has served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since September 2002. He served as Executive Vice President and Chief Financial Officer of the Delivery Group of Reliant Energy from July 2001 to September 2002. Mr. Whitlock served as the Vice President, Finance and Chief Financial Officer of Dow

AgroSciences, a subsidiary of The Dow Chemical Company, from 1998 to 2001. He currently serves on the Board of Directors of KiOR, Inc. We believe Mr. Whitlock's energy industry and financial experience provides the board of directors with valuable experience in our financial and accounting matters.

Peter B. Delaney has been a director of our general partner since May 2013. Mr. Delaney is Chairman, President and Chief Executive Officer of OGE Energy and Chairman and Chief Executive Officer of OG&E. From December 2011 to July 2013, Mr. Delaney was Chairman, President and Chief Executive Officer of OGE Energy and OG&E. From January 2011 to December 2011, Mr. Delaney was Chairman and Chief Executive Officer of OGE Energy and OG&E. From September 2007 to December 2010, Mr. Delaney was Chairman, President and Chief Executive Officer of OGE Energy and OG&E. From January 2007 to September 2007, Mr. Delaney was President and Chief Operating Officer of OGE Energy and OG&E. From 2004 to January 2007, he was Executive Vice President and Chief Operating Officer of OGE Energy and OG&E. From 2002 to 2004, Mr. Delaney was Executive Vice President, Finance and Strategic Planning for OGE Energy and served from 2002 to 2013 as the Chief Executive Officer of Enogex LLC. Mr. Delaney is a member of the Board of Directors of the Federal Reserve Bank of Kansas City. Mr. Delaney has been a director of OGE Energy and OG&E since January 2007. We believe his extensive knowledge of the industry and us, our operations and people, gained with OGE Energy and its affiliates in positions of increasing responsibility provides the board with valuable experience.

Sean Trauschke has been a director of our general partner since May 2013. From May 1, 2013 to December 11, 2013, he served as Acting Chief Financial Officer of our general partner. Mr. Trauschke has been the Vice President and Chief Financial Officer of OGE Energy and OG&E since 2009 and President of OG&E since July 2013. He was Chief Financial Officer of Enogex Holdings from 2010 to 2013 and Chief Financial Officer of Enogex LLC from 2009 to 2013. From 2008 to 2009, Mr. Trauschke was the Senior Vice President—Investor Relations and Financial Planning of Duke Energy. We believe Mr. Trauschke's energy industry and financial experience provides the board of directors with valuable experience in our financial and accounting matters.

Lynn L. Bourdon, III was appointed as President and Chief Executive Officer of our general partner effective February 1, 2014. Mr. Bourdon will assume a position on the board of directors of our general partner upon completion of this offering. Mr. Bourdon was Group Senior Vice President, NGL and Natural Gas Marketing of the general partner of Enterprise Products Partners L.P. from April 2012 until January 2014 and Senior Vice President (Supply & Marketing) from 2004 to April 2012. Mr. Bourdon has also served as Senior Vice President and Chief Commercial Officer with Orion Refining Corporation, as a Partner in En*Vantage, Inc., as Senior Vice President of Commercial Operations for PG&E Gas Transmission and as Vice President, NGL Marketing & Development at its predecessor company, Valero Energy Corporation. Earlier in his career, Mr. Bourdon served 12 years with Dow Chemical Company in the engineering, business and commercial areas. We believe that Mr. Bourdon's substantial prior experience as an executive officer of companies engaged in energy-related businesses, together with his service as the President and Chief Executive Officer of our general partner, will provide the board with valuable insight.

Stephen E. Merrill was appointed as Executive Vice President of Finance and Chief Administrative Officer of our general partner in December 2013. Mr. Merrill has been the Chief Operating Officer of Enogex LLC since 2011. From 2009 to 2011, Mr. Merrill was the Vice President–Human Resources of OGE Energy Corp. and OG&E and was the Vice President and Chief Financial Officer of Enogex LLC from 2008 to 2009.

E. Keith Mitchell has been the Chief Operating Officer of our general partner since July 2013. From 2011 to August 2013, Mr. Mitchell was President and Chief Operating Officer of Enogex Holdings and President of Enogex LLC. From 2008 to 2011, Mr. Mitchell was Senior Vice President and Chief Operating Officer of Enogex LLC.

Mark C. Schroeder has been the General Counsel of our general partner since July 2013. Mr. Schroeder is the senior vice president and deputy general counsel of Regulation for CenterPoint Energy and has worked in CenterPoint Energy's legal department for 10 years. From 2003 to 2011, Mr. Schroeder was general counsel of CenterPoint Energy's midstream business unit. He also worked for El Paso Energy.

Board Leadership Structure

Under the limited liability company agreement of our general partner, the right to appoint the chairman of the board of our general partner will rotate between OGE Energy and CenterPoint Energy every two years. The term of the initial chairman of the board will expire on May 1, 2015, at which time will have the right to appoint the next chairman. Although the board of directors of our general partner has no policy with respect to the separation of the offices of chairman of the board and chief executive officer, we do not expect these positions to be occupied by the same individual due to the rotating chairmanship provision in the general partner's limited liability company agreement. Members of the board of directors of our general partner are appointed by OGE Energy and CenterPoint Energy. Accordingly, unlike holders of common stock in a corporation, our unitholders will have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Board Role in Risk Oversight

Our corporate governance guidelines will provide that the board of directors of our general partner is responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility will be largely satisfied by the audit committee, which is responsible for reviewing and discussing with management and our registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies.

Committees of the Board of Directors

Audit Committee

Within twelve months of the date our common units are first traded on the NYSE, our general partner will have an audit committee comprised of at least three directors who meet the independence and experience standards established by the NYSE and the Exchange Act. The audit committee will assist the board of directors of our general partner in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee will have the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee.

Conflicts Committee

At least two members of the board of directors of our general partner will serve on our conflicts committee. The conflicts committee will determine if the resolution of any conflict of interest referred to it by our general partner is in our best interests. There is no requirement that our general partner seek the approval of the conflicts committee for the resolution of any conflict. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, may not hold an ownership interest in the general partner or its affiliates other than common units or awards under any long-term incentive plan, equity compensation plan or similar plan implemented by the general partner or the partnership, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors. Any matters approved by the conflicts committee in good faith will be deemed to be approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. Any unitholder challenging any matter approved by the conflicts committee will have the burden of proving that the members of the conflicts committee did not believe that the matter was in the best interests of our partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal counsel, accountants, appraisers, management consultants and investment bankers, where our general partner (or any members of the board of directors of our general partner including any member of the conflicts committee) reasonably believes the advice or opinion to be within such person's professional or expert competence, will be conclusively presumed to have been done or omitted in good faith.

Reimbursement of Expenses of Our General Partner

Our general partner will not receive any management fee or other compensation for its management of our partnership; however, our general partner will be reimbursed by us for (i) all salary, bonus, incentive compensation and other amounts paid to any employee of the general partner that manages our business and (ii) all overhead and general and administrative expenses allocable to us that are incurred by the general partner. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us.

Director Compensation

The officers or employees of our general partner or of either of our sponsors who also serve as directors of our general partner will not receive additional compensation for their service as a director of our general partner. Directors of our general partner who are not officers or employees of our general partner or of either of our sponsors, or "independent directors," will receive compensation as described below. In addition, independent directors will be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees. Each director will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

Each of our general partner's independent directors will receive an annual compensation package, which is initially expected to consist of $ in annual cash compensation. In addition, independent directors who chair the Audit and Conflicts committees will receive an additional $ in cash compensation.

Compensation Discussion and Analysis

Except for our President and Chief Executive Officer, who will be employed by one of our subsidiaries, all of our executive officers and other personnel necessary for our business to function are employed and compensated by OGE Energy or CenterPoint Energy, to whom we reimburse certain costs pursuant to the terms of transitional seconding agreements or transitional services agreements with each. Under the seconding agreements, we are required to reimburse OGE Energy and CenterPoint Energy for certain employment-related costs, including base salary and short and long-term compensation costs and OGE Energy's and CenterPoint Energy's share of costs related to taxes, insurance and other benefit matters. Under the services agreements, we are required to reimburse OGE Energy and CenterPoint Energy for their direct expenses or, where the direct expenses cannot reasonably be determined, an allocated cost as set forth in the agreements. Please see "Certain Relationships and Related Party Transactions—Services Agreements" and "—Employee Agreements." The officers of our general partner (excluding our President and Chief Executive Officer), as well as the employees of OGE Energy and CenterPoint Energy who provide services to us, may participate in employee benefit plans and arrangements sponsored by OGE Energy or CenterPoint Energy, respectively, including plans that may be established in the future.

Our President and Chief Executive Officer, Mr. Bourdon, will be employed directly by one of our subsidiaries. We expect that Mr. Bourdon will join the board of directors of our general partner upon the completion of this offering. The board of directors of our general partner, excluding Mr. Bourdon, has ultimate decision-making authority with respect to Mr. Bourdon's compensation.

Responsibility and authority for compensation-related decisions for executive officers of our general partner employed by OGE Energy or CenterPoint Energy will reside with OGE Energy or CenterPoint Energy and their committees, as applicable, so long as such officers are employed by OGE Energy or CenterPoint Energy pursuant to the terms of the transitional seconding agreements or transitional services agreements and subject to consultation with the board of our general partner. Any such compensation decisions will not be subject to any approvals by the board of directors of our general partner or any committees thereof. Please read "Certain Relationships and Related Party Transactions—Employee Agreements" and "—Services Agreements."

In this section, we describe and discuss the principles and policies used in setting the compensation of our Chief Operating Officer (who, as of December 31, 2013, was our principal executive officer), Executive Vice President of Finance and Chief Administrative Officer and our General Counsel, whom we collectively refer to as our "named executive officers." The board of directors of our general partner appointed a new President and Chief Executive Officer effective February 1, 2014. Compensation paid or awarded by us in 2013 with respect to our Chief Operating Officer and our Executive Vice President of Finance and Chief Administrative Officer, each of whom has been seconded to our general partner, reflects only the portion of compensation expense that is payable by us, which will be determined based on the amount of time each named executive officer spent working for us relative to the amount of time each spent working for OGE Energy or CenterPoint Energy, as applicable. We are not providing detailed compensation information with respect to our two former Acting Chief Financial Officers, Mr. Whitlock and Mr. Trauschke, or our General Counsel, Mr. Schroeder, each of whom provided services to us pursuant to the services agreements. Amounts allocated to us by OGE Energy and CenterPoint Energy for the services provided by these individuals were based on an allocation of overhead and other costs of the services provided. Please read "Certain Relationships and Related Party Transactions—Services Agreements."

On or prior to December 31, 2014, we will provide offers of employment to those seconded employees that we determine to hire, including those we determine to hire as executive officers of our general partner. Until those seconded employees become our employees, we expect that they will be compensated in a manner similar to the compensation of the executive and non-executive officers of OGE Energy, in the case of current employees of OGE Energy, and CenterPoint Energy, in the case of current employees of CenterPoint Energy.

The following discussion relating to compensation paid to named executive officers of OGE Energy and CenterPoint Energy is based on information provided to us by OGE Energy and CenterPoint Energy and does not purport to be a complete discussion and analysis of OGE Energy's and CenterPoint Energy's executive compensation philosophy and practices. OGE Energy's and CenterPoint Energy's compensation policies with respect to their other executive officers are generally consistent with the policies discussed below, except that compensation decisions are made by management, rather than at the board level. Unless and until they become our employees, the elements of compensation discussed below, and OGE Energy's and CenterPoint Energy's decisions with respect to future changes to the levels of such compensation related to our named executive officers are subject to the discretion of OGE Energy, in the case of Mr. Mitchell and Mr. Merrill, and CenterPoint Energy, in the case of Mr. Schroeder.

OGE Energy's Compensation Philosophy

General

OGE Energy's compensation committee administers its executive compensation program, which is premised on two basic principles. First, overall compensation levels must be sufficiently competitive to attract and retain talented leaders. At the same time, OGE Energy believes that compensation should be set at reasonable and responsible levels, consistent with its continuing focus on controlling costs. Second, the executive compensation program should be substantially performance-based and should align the interests of executives with those of shareholders.

Three key components of OGE Energy's executive compensation program are salary, annual incentive awards under its Annual Incentive Plan and long-term incentive awards under its Stock Incentive Plan. Salaries are a critical element of executive compensation because they provide executives with a base level of monthly income. OGE Energy's compensation committee's intent in setting salaries is to pay competitive rates based on an individual's responsibilities, experience and level of performance. The annual and long-term incentive awards of an executive's compensation are directly linked to performance. Payouts of these portions of an executive's compensation are placed at risk and require the accomplishment of specific results that are designed to benefit OGE Energy and its shareholders, both in the long and short term.

Base Salary

The base salaries for executive officers are designed to be competitive with a predetermined peer group. Base salaries of executive officers were determined based primarily on an individual's annual performance evaluation, using as a guideline the salaries at the median of the range for executives with similar duties in the appropriate survey group.

Annual Incentive Compensation

Annual incentive awards with respect to performance were made under OGE Energy's Annual Incentive Plan, which provides executive officers with annual incentive awards, the payment of which is dependent entirely on the achievement of OGE Energy's performance goals that were established by its compensation committee.

The amount of the award for each executive officer is expressed as a percentage of salary (the "targeted amount"), with the officer having the ability, depending upon achievement of OGE Energy's performance goals, to receive from 0 percent to 150 percent of such targeted amount.

Long-Term Incentive Compensation

Long-term incentive awards also are made under OGE Energy's Stock Incentive Plan, which provides for the grant of any or all of the following types of awards: stock options, SARs, restricted stock and performance units; however, OGE Energy's compensation committee has not granted stock options or SARs since 2004 and has no intention to issue stock options or SARs in the foreseeable future. OGE Energy's compensation committee sets a targeted amount of long-term incentive compensation to be awarded each executive officer, which amount is expressed as a percentage of the individual's base salary that is approved by OGE Energy's compensation committee, with the officer having the ability, depending upon achievement of OGE Energy's performance goals, to receive from 0 to 200 percent of such targeted amount.

OGE Energy's compensation committee makes annual awards of long-term compensation to executive officers solely in the form of performance units with payout of the performance units being dependent on achievement of OGE Energy's performance goals set by the compensation committee. In connection with the annual award of performance units for each of the last five years, the compensation committee has used two OGE Energy performance goals, with payout of 75 percent of the performance units awarded annually being based on the relative total shareholder return of the OGE Energy's common stock over a three-year period compared to a peer group and the remaining 25 percent being based on the growth in the OGE Energy's EPS over the same period compared to an earnings growth target set by the compensation committee.

Other Benefits

OGE Energy also provides a basic benefits package generally to all employees, which includes health, disability and life insurance.

CenterPoint Energy's Compensation Philosophy

General

CenterPoint Energy tries to provide compensation that is competitive, both in total level and in individual components, with the companies it believes are its peers and other likely competitors for executive talent. By competitive, it means that total compensation and each element of compensation corresponds to a market-determined range. CenterPoint Energy targets the market median (50th percentile) for each major element of compensation because it believes the market median is a generally accepted benchmark of external competitiveness.

To help ensure market-based levels of compensation, CenterPoint Energy measures the major elements of compensation annually for a position against available data for similar positions in other companies. The salary level and short term and long term incentive target percentages are based on market data for the officer's position. Compensation levels can vary compared to the market due to a variety of factors such as experience, scope of responsibilities, tenure and individual performance. CenterPoint Energy also motivates its executives to achieve individual and business performance objectives by varying their compensation in accordance with the success of its businesses. Actual compensation in a given year will vary based on CenterPoint Energy's performance, and to a lesser extent, on qualitative appraisals of individual performance.

Base Salary

Base salary is the foundation of total compensation. Base salary recognizes the job being performed and the value of that job in the competitive market. Base salary must be sufficient to attract and retain the executive talent necessary for CenterPoint Energy's continued success and provides an element of compensation that is not at risk in order to avoid fluctuations in compensation that could distract executives from the performance of their responsibilities. CenterPoint Energy's intent is that base salary for most senior executives will be positioned near the 50th percentile of base salaries in the peer group and published compensation surveys.

Short Term Incentives

CenterPoint Energy's short term incentive plan provides an annual cash award that is designed to link each employee's annual compensation to the achievement of annual performance objectives for CenterPoint Energy and the individual's business unit, as well as to recognize the employee's performance during the year. The target for each employee is expressed as a percentage of base salary earned during the year.

CenterPoint Energy's compensation committee determines short term incentive targets by taking into account the market analysis performed annually by its consultant as described above and recommendations from the chief executive officer for officers other than himself. The achievement of the performance objectives approved by the compensation committee determines the funding of the short term incentive plan for the year. The compensation committee establishes and approves the specific performance objectives based on possible objectives included in the short term incentive plan. Performance objectives are based on company and business unit financial and operational factors determined to be critical to achieving CenterPoint Energy's desired business plans. Performance objectives are designed to reflect goals and objectives to be accomplished over a 12-month measurement period; therefore, incentive opportunities under the plan are not impacted by compensation amounts earned in prior years.

Long Term Incentives

CenterPoint Energy provides a long term incentive plan in which each of its executive officers and certain other management-level employees participate. Its long term incentive plan is designed to reward participants for sustained improvements in CenterPoint Energy's financial performance and increases in the value of its common stock and dividends over an extended period.

The compensation committee authorizes grants annually at a regularly scheduled meeting during the first quarter of the year. Grants can be made from a variety of award types authorized under its long term incentive plan. In recent years, CenterPoint Energy has emphasized performance-based shares. CenterPoint Energy has also granted restricted stock unit awards, which it sometimes refers to as "stock awards", which vest based on continued service over a three-year period and the achievement of a performance goal based on the level of dividends declared over the vesting period. Over a period of years, if CenterPoint Energy achieves expected business performance, it expects that the long term incentive plan should pay out at target levels.

Other Benefits

CenterPoint Energy also provides a basic benefits package generally to all employees, which includes health, disability and life insurance.

Retention and Severance Agreements

In November 2013, an affiliate of OGE Energy entered into a retention agreement with Mr. Mitchell. Pursuant to the terms of the retention agreement, Mr. Mitchell will be entitled to receive a retention benefit of $500,000 if he (A) is continuously employed by OGE Holdings, us, our general partner or an affiliate of us or our general partner (a Successor Employer) as of January 2, 2016, (B) is terminated by OGE Holdings or a Successor Employer without cause (as defined therein) prior to January 2, 2016 or (C) ceases to be employed by OGE Holdings or a Successor Employer prior to January 2, 2016 due to his death or disability (as defined therein) (in each case, the Vesting Date). If Mr. Mitchell's employment is terminated prior to the Vesting Date (i) by OGE Holdings or a Successor Employer for cause or (ii) by Mr. Mitchell other than due to death or disability, then Mr. Mitchell will not be entitled to receive the retention benefit. The retention benefit is in addition to, and not in lieu of, all other accrued or vested or earned compensation, rights, options or benefits payable under any retirement plan, bonus, savings or other compensation plan, stock incentive plan, life insurance plan, health plan, or disability plan or any amounts otherwise payable to Mr. Mitchell under the severance plan discussed below.

Our sponsors have adopted severance plans for certain of their officers, including Mr. Mitchell and Mr. Merrill, whose employment has been seconded to us or our general partner. Under the terms of the plans, if a participant's employment with the applicable sponsor and its affiliates, including us and our general partner, is terminated for reasons other than death, disability (as defined therein) or cause (as defined therein) prior to December 31, 2014, such participant is entitled, subject to limited exceptions, to severance benefits.

If the terminated participant has not received an offer from the applicable sponsor or any affiliate of comparable employment with relocation (as defined therein) as of his or her termination date such participant will be entitled to a lump-sum cash severance benefit in an amount equal to (i) 52 weeks of the participant's weekly compensation plus (ii) such participant's target award under such sponsor's short-term incentive plan.

If the terminated participant has received and declined an offer from the applicable sponsor or any affiliate of comparable employment with relocation as of his or her termination date such participant shall be entitled to a lump sum cash severance benefit in an amount equal to (i) two (2) weeks of the participant's weekly compensation multiplied by the number of full years of service credited to the participant as of his or her termination date, provided that such cash severance benefit shall not be less than 12 weeks of the participant's weekly compensation nor more than 36 weeks of the participant's weekly compensation and (ii) such participant's target award under the applicable sponsor's short term incentive plans, if any, based upon the participant's actual eligible earnings through the participant's termination date.

The participant also is entitled to continued medical, dental and vision benefits (provided that such participant is eligible for and timely elects continuation of coverage in accordance with the Consolidated Omnibus Budget Reconciliation Act of 1985 (COBRA) for the applicable period required by COBRA). A participant who has not received an offer from the applicable sponsor or any affiliate of comparable employment with relocation as of his or her termination date will be entitled to receive outplacement services, not to exceed a maximum of nine months, provided the participant initiates such services within 60 days of his or her termination date.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our units that will be owned upon the consummation of this offering by:

- each person known by us to be a beneficial owner of more than 5% of the units;
- all of the directors and director nominees of our general partner;
- each named executive officer of our general partner; and
- all directors, director nominees and executive officers of our general partner as a group.

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. 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.

Percentage of total units to be beneficially owned after this offering is based on common units outstanding. The table assumes that the underwriters' option to purchase additional units is not exercised.

Name of Beneficial Owner	Common Units to be Beneficially Owned	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
OGE Energy Corp.(1) 321 North Harvey Oklahoma City, Oklahoma 73101					
CenterPoint Energy, Inc.(2) 1111 Louisiana Houston, Texas 77002					
ArcLight Capital Partners, LLC(3) 200 Clarendon Street, 55th Floor Boston, Massachusetts 02117					
Scott M. Prochazka					
Gary L. Whitlock					
Peter B. Delaney					
Sean Trauschke					
Lynn L. Bourdon, III					
Stephen E. Merrill					
E. Keith Mitchell					
Mark C. Schroeder					
All directors and executive officers as a group (8 persons)					

(1) OGE Energy Corp. owns all of the outstanding membership interests in OGE Enogex Holdings LLC, which is the record holder of the common units and subordinated units. OGE Energy Corp. is the beneficial owner of all common and subordinated units held by OGE Enogex Holdings LLC.

(2) CenterPoint Energy, Inc. indirectly owns all of the outstanding equity interests in CenterPoint Energy Resources Corp., which is the record holder of the common units and subordinated units. CenterPoint Energy, Inc. is the beneficial owner of all common and subordinated units held by CenterPoint Energy Resources Corp.

(3) ArcLight owns all of the outstanding membership interests in Enogex Holdings LLC and Bronco Midstream Infrastructure, LLC, which are the record holders of the common units. ArcLight Capital Partners, LLC is the investment adviser of ArcLight and may be deemed to be the beneficial owner of all common held by Enogex Holdings LLC.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, OGE Energy and CenterPoint Energy collectively will own our general partner and common units and subordinated units representing an aggregate % limited partner interest in us. ArcLight also will own common units representing a % limited partner interest in us. In addition, our general partner will own a non-economic general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and Its Affiliates

The following information summarizes the distributions and payments made or to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and any liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, may not equal the distributions and payments that would result from arm's-length negotiations.

Formation Stage

The aggregate consideration received by our general partner and its affiliates for the contribution of certain assets and liabilities to us:

- 498,866,993 common units;
- a non-economic general partner interest;
- all of the incentive distribution rights; and
- repayment of $1.05 billion of intercompany indebtedness owed by us to CenterPoint Energy with the proceeds of our term loan facility.

In connection with this offering, of CenterPoint Energy's common units and of OGE Energy's common units will be converted into subordinated units.

Operational Stage

Distributions of Available Cash to Our General Partner and Its Affiliates. We will generally make cash distributions to unitholders pro rata, including affiliates of our general partner as holders of an aggregate of common units and all of the subordinated units. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target level.

Payments to Our General Partner and Its Affiliates. Pursuant to the services agreements, we will reimburse OGE Energy and CenterPoint Energy and their respective affiliates for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. Please see "—Services Agreements."

Our general partner and its affiliates will be entitled to reimbursement for any other expenses they incur on our behalf and any other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business to the extent not otherwise covered by the services agreements. Our partnership agreement provides that our general partner will determine any such expenses that are allocable to us in good faith.

Withdrawal or Removal of Our General Partner. If our general partner withdraws or is removed, 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 the General Partner."

Liquidation Stage

Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Agreements Governing the Offering Transactions

We have entered into various documents and agreements with our sponsors and ArcLight related to our formation. Some of these agreements are not the result of arm's-length negotiations, and they, or any of the transactions that they provide for, are not and may not be effected on terms at least as favorable to the parties to these agreements as could have been obtained from unaffiliated third parties. Because some of these agreements relate to formation transactions that, by their nature, would not occur in a third-party situation, it is not possible to determine what the differences would be in the terms of these transactions when compared to the terms of transactions with an unaffiliated third party. We believe the terms of these agreements to be comparable to the terms of agreements used in similarly structured transactions.

Master Formation Agreement

Pursuant to a master formation agreement among (i) ArcLight, (ii) CenterPoint Energy and (iii) OGE Energy:

- CEFS was converted into a Delaware limited partnership that became Enable Midstream Partners, LP;
- CenterPoint Energy indirectly contributed to CEFS, CenterPoint Energy's equity interests in each of CenterPoint Energy Gas Transmission Company, LLC, a Delaware limited liability company, CenterPoint Energy—Mississippi River Transmission, LLC, a Delaware limited liability company, certain of its other midstream subsidiaries and a 24.95% interests in SESH; and
- OGE Energy indirectly contributed 100% of the equity interests in Enogex to Enable Midstream Partners, LP.

As consideration for these assets and agreements, we issued 141,956,176 common units (28.456% of our limited partner interests) to an affiliate of OGE Energy, 291,002,583 common units (58.333% of our limited partner interests) to an affiliate of CenterPoint Energy and 65,908,224 common units (13.212% of our limited partner interests) to ArcLight. In connection with this offering, of CenterPoint Energy's common units and of OGE Energy's common units will be converted into subordinated units. We also issued incentive distribution rights to Enable GP, and 40% of such incentive distribution rights were allocated to CenterPoint Energy and 60% of such incentive distribution rights were allocated to OGE Energy. CenterPoint Energy and OGE Energy were each allocated 50% of Enable GP's management units.

Acquisition of Remaining CenterPoint Energy Interest in SESH

CenterPoint Energy owns a 25.05% interest in SESH. The remaining 24.95% and 50.0% ownership interests are held by us and affiliates of Spectra Energy Corp, respectively. Under the master formation agreement, CenterPoint Energy has certain put rights, and we have certain call rights, exercisable with respect to the aggregate 25.05% interest in SESH retained by CenterPoint Energy. Specifically, the rights are exercisable with respect to a 24.95% interest in SESH (which may be exercised no earlier than May 2014) and a 0.1% interest in SESH (which may be exercised no earlier than May 2015). Under the put and call rights, CenterPoint Energy would contribute to us its interest in SESH at a price equal to the fair market value of the interest at the time the put right or call right is exercised. If CenterPoint Energy were to exercise its put rights or we were to exercise our call rights, CenterPoint Energy would contribute to us its 24.95% interest in SESH in exchange for common units and its 0.1% interest in SESH in exchange for common units. In each case, subject to certain restrictions, a cash payment may be required to be made, payable either from CenterPoint Energy to us or from us to CenterPoint Energy, in an amount such that the total consideration exchanged is equal in value to the fair market value of the contributed interest in SESH. Our rights in connection with the interest in SESH retained by CenterPoint Energy will be exercised by the directors of our general partner appointed by OGE Energy. Please read "Risk Factors—Risks Related to Our Business—Under certain circumstances, affiliates of Spectra Energy Corp will have the right to purchase an ownership interest in SESH at fair market value."

Services Agreements

We have entered into services agreements with each of OGE Energy and CenterPoint Energy pursuant to which they perform certain administrative services for us that are generally consistent with the level and type of services they provided to each of their respective businesses prior to our formation. These services include accounting, finance, legal, risk management, information technology and human resources. We are required to reimburse OGE Energy and CenterPoint Energy for their direct expenses or, where the direct expenses cannot reasonably be determined, an allocated cost as set forth in the agreements. Unless otherwise approved by the board of directors of our general partner, our reimbursement obligations are capped at amounts set forth in our annual budget, which are $44 million and $30 million for CenterPoint Energy and OGE Energy, respectively, for the year ended December 31, 2013. The initial term of the services agreements ends in May 2016, after which date they continue on a year-to-year basis unless terminated by us upon 90 days' notice. We may terminate each services agreement, or the provision of any services thereunder, upon approval by the board of directors of our general partner and 180 days' notice to OGE Energy or CenterPoint Energy, as applicable.

Omnibus Agreement

We have entered into an omnibus agreement with OGE Energy, CenterPoint Energy and ArcLight that addresses competition and indemnification matters.

Competition

Subject to the exceptions described below, each of OGE Energy and CenterPoint Energy is required to hold or otherwise conduct all of its respective midstream operations located within the United States through us. This requirement will cease to apply to both OGE Energy and CenterPoint Energy as soon as either OGE Energy or CenterPoint Energy ceases to hold any interest in our general partner or at least 20% of our common units. "Midstream operations" generally means, subject to certain exceptions, the gathering, compression, treatment, processing, blending, transportation, storage, isomerization and fractionation of crude oil and natural gas, its associated production water and enhanced recovery materials such as carbon dioxide, and its respective constituents and the following products: methane, NGLs (Y-grade, ethane, propane, normal butane, isobutane and natural gasoline), condensate, and refined products and distillates (gasoline, refined product blendstocks, olefins, naphtha, aviation fuels, diesel, heating oil, kerosene, jet fuels, fuel oil, residual fuel oil, heavy oil, bunker fuel, cokes, and asphalts), to the extent such activities are located within the United States.

If OGE Energy or CenterPoint Energy intends to cease using the assets of such restricted business within 12 months of the acquisition of such business, then the restrictions discussed immediately above do not apply; provided, however, that OGE Energy or CenterPoint Energy, as applicable, must notify us following completion of such acquisition.

In addition, if OGE Energy or CenterPoint Energy acquires any assets or equity of any person engaged in midstream operations with such midstream operations having a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired midstream operations that have not been offered to us), the acquiring party will be required to offer to us the opportunity to acquire such assets or equity for such value; however, the acquiring party will not be obligated to offer any such assets or equity to us if the acquiring party intends to cease using them in midstream operations within 12 months of their acquisition. If we do not exercise this option then the acquiring party will be free to retain and operate such midstream operations; however, if the fair market value of such midstream operations is greater than 66 $^2/_3$% of the fair market value of all of the assets being acquired in such transaction, then the acquiring party must use commercially reasonable efforts to dispose of such midstream operations within 24 months from the date on which our option to purchase has expired.

Indemnification

Under the omnibus agreement, OGE Energy and CenterPoint Energy are obligated to indemnify us for specified breaches of representations and warranties in the master formation agreement pursuant to which we were formed related to:

- their authority to enter into the transactions that formed us and the capitalization of the entities contributed to us;
- permits related to the operation of the assets contributed to us;
- compliance with environmental laws;
- title to properties and rights of way;
- the tax classification of the entities contributed to us;
- indemnified taxes; and
- events and conditions associated with their ownership and operation of the contributed assets.

ArcLight is obligated to indemnify us with respect to the first bullet point above and shares an indemnification obligation with OGE Energy with respect to the sixth and seventh bullet points above.

OGE Energy's and CenterPoint Energy's maximum liability for this indemnification obligation with respect to permit, environmental and title representations will not exceed $250 million, and neither OGE Energy nor CenterPoint Energy will have any obligation under this indemnification until our aggregate indemnifiable losses exceed $25 million.

OGE Energy's and CenterPoint Energy's indemnification obligations will survive (i) for permit matters until May 1, 2014, (ii) for environmental and title and rights of way matters until May 1, 2016 and (iii) for tax classification matters and indemnified taxes until 30 days following the expiration of the applicable statute of limitations. Indemnification for authority and capitalization matters survives indefinitely.

Names and Insignia and Other Matters

The omnibus agreement also addresses our use of certain names and insignia. We have agreed not to use or otherwise exploit any service marks, trade names, logos or similar property including the words "CenterPoint Energy," "OGE" or "Enogex." We have also agreed, prior to May 1, 2014, to use commercially reasonable efforts to remove such names and insignia from our assets.

Registration Rights Agreement

Pursuant to a registration rights agreement we entered into with affiliates of OGE Energy, CenterPoint Energy and ArcLight, those affiliates have specified demand and piggyback registration rights with respect to the registration and sale of their common units. In particular, beginning 180 days after the closing of this offering, affiliates of OGE Energy and CenterPoint Energy will each have the right to cause us to prepare and file a registration statement with the SEC covering the offering and sale of their common units. At any time following the time when we are eligible to file a registration statement on Form S-3, ArcLight will have the right to cause us to prepare and file a registration statement on Form S-3 with the SEC covering the offering and sale of its common units. We are not obligated to effect more than (i) three such demand registrations for OGE Energy and CenterPoint combined, or (ii) two such demand registrations (and no more than one in any twelve-month period) for ArcLight. If we propose to file a registration statement (other than pursuant to a demand registration discussed above, or other than for an employee benefit plan), OGE Energy, CenterPoint Energy and/or ArcLight may request to "piggyback" onto such registration statement in order to offer and sell their common units. We have agreed to pay all registration expenses in connection with such demand and piggyback registrations.

Registration expenses do not include underwriters' compensation, stock transfer taxes or counsel fees. We have also agreed to pay reasonable fees and expenses of counsel incurred by Enogex Holdings, LLC in connection with our initial public offering registration; provided, however, that such fees shall not exceed $250,000 if our initial public offering occurs on or before December 31, 2013, which amount shall increase by $25,000 per quarter (and partial quarter) after such date until our initial public offering occurs. In addition, Enogex Holdings, LLC retains the right to be involved in the planning and negotiating of the terms of our initial public offering, provided that Enogex Holdings, LLC holds a certain percentage of our common units.

Employee Agreements

We have entered into an employee transition agreement with OGE Energy and CenterPoint Energy and a transitional seconding agreement with each of OGE Energy and CenterPoint Energy, pursuant to which they have agreed to second certain of their employees to us. Each of the seconded employees works full time for us and our subsidiaries but remains employed by OGE Energy or CenterPoint Energy. We are required to reimburse OGE Energy and CenterPoint Energy for certain employment-related costs, including base salary and short and long-term compensation costs and CenterPoint Energy's and OGE Energy's share of costs related to taxes, insurance and other benefit matters. On or prior to December 31, 2014, we will provide offers of employment to those seconded employees that we determine to hire. As of September 30, 2013 all of the individuals providing services to us were doing so as seconded employees by OGE Energy and CenterPoint Energy or pursuant to services agreements with OGE Energy or CenterPoint Energy, and we did not have any direct employees.

Tax Sharing Agreements

We have entered into a tax sharing agreement with OGE Energy, CenterPoint Energy and Enable GP pursuant to which we have agreed to reimburse them for state income and franchise taxes attributable to our activity (including the activities of our direct and indirect subsidiaries) that is reported on their state income or franchise tax returns filed on a combined or unitary basis. Our general partner is responsible for determining whether OGE Energy or CenterPoint Energy is required to include our activities on a consolidated, combined or unitary tax return. Reimbursements under the agreement equal the amount of tax that we and our subsidiaries would be required to pay if we were to file a consolidated, combined or unitary tax return separate from OGE Energy or CenterPoint Energy. We are required to pay the reimbursement within 90 days of OGE Energy or CenterPoint Energy filing the combined or unitary tax return on which our activity is included, subject to certain prepayment provisions.

Contracts with Affiliates

Transportation and Storage Agreement with OG&E

Our current contract with OG&E provides for no-notice load-following transportation services and storage services. The stated term of the OG&E contract expired April 30, 2009, but the contract remains in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 90 days prior to the commencement of the succeeding annual period. In the year ended December 31, 2012, on a pro forma basis, we recorded revenues from OG&E of $34.8 million for transportation services and $12.9 million for natural gas storage services.

Transportation and Storage Agreements with CenterPoint Energy

EGT provides the following services to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma, and Northeast Texas: (1) firm transportation with seasonal contract demand, (2) firm storage, (3) no notice transportation with associated storage, and (4) maximum rate firm transportation. The first three services are in effect through March 31, 2021, and will remain in effect from year to year thereafter unless either party provides 180 days' written notice prior to the contract termination date. The maximum rate firm transportation is in effect, through March 31, 2015, but will extend for an additional three-year term unless either party provides 180 days written notice prior to the contract termination date.

MRT's current firm transportation and firm storage agreements with CenterPoint Energy are in effect through May 15, 2018, but will continue year to year thereafter unless either party provides twelve months' written notice prior to the contract termination date.

For the twelve months ended December 31, 2012, on a pro forma basis, revenues from our firm interstate natural gas transportation and storage contracts attributable to CenterPoint Energy were $95.2 million.

Review, Approval or Ratification of Transactions with Related Persons

The board of directors of our general partner will adopt a related party transactions policy 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 review on at least a quarterly basis 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 related party transactions policy will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The related party transactions policy will provide that, in determining whether or not 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: (1) whether there is an appropriate business justification for the transaction; (2) the benefits that accrue to us as a result of the transaction; (3) the terms available to unrelated third parties entering into similar transactions; (4) the impact of the transaction on a director's 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 immediate family member of a director is a partner, shareholder, member or executive officer); (5) the availability of other sources for comparable products or services; (6) whether it is a single transaction or a series of ongoing, related transactions; and (7) whether entering into the transaction would be consistent with the code of business conduct and ethics.

The related party transactions policy 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.

CONFLICTS OF INTEREST AND FIDUCIARY 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 OGE Energy and CenterPoint Energy, on the one hand, and us and our limited partners, on the other hand. The directors and 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 limited partners. 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 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 for resolving conflicts of interest. Our partnership agreement also specifically defines the remedies available to limited partners for 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 any other partner, on the other hand, 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 limited partners if the resolution of the conflict is:

- approved by the conflicts committee;
- 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.

If our general partner does not seek approval from the conflicts committee and our general partner's 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 or fourth bullet points above, then it will be presumed that, in making its decision, the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee of our general partner's board of directors 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. Please read "Management—Committees of the Board of Directors—Conflicts Committee" for information about the conflicts committee of our general partner's board of directors.

Conflicts of interest could arise in the situations described below, among others.

Neither Our Partnership Agreement Nor any Other Agreement Requires OGE Energy or CenterPoint Energy to Pursue a Business Strategy that Favors us or Utilizes our Assets or Dictates what Markets to Pursue or Grow. OGE Energy's and CenterPoint Energy's Respective Directors and Officers have a Fiduciary Duty to Make these Decisions in the Best Interests of their Respective Companies, which may be Contrary to Our Interests.

Because all of the officers and directors of our general partner are also directors and/or officers of OGE Energy or CenterPoint Energy, such directors and officers have fiduciary duties to their respective companies that may cause them to pursue business strategies that disproportionately benefit OGE Energy or CenterPoint Energy, as applicable, or which otherwise are not in our best interests.

Contracts Between us, on the One Hand, and Our General Partner and Its Affiliates, on the Other Hand, are not and will not be the Result of Arm's-Length Negotiations.

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. Our partnership agreement generally provides that any affiliated transaction, such as an agreement, contract or arrangement between us and our general partner and its affiliates that does not receive unitholder or conflicts committee approval, must be 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
- "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 and its affiliates 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 dealing with that use. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. There is no obligation of our general partner and its affiliates to enter into any contracts of this kind.

Our General Partner's Affiliates may Compete with us and Neither Our General Partner Nor Its Affiliates have any Obligation to Present Business Opportunities to us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. However, except as provided in the omnibus agreement, OGE Energy and CenterPoint Energy and certain of their affiliates are not prohibited from engaging in other businesses or activities, including those that might directly compete with us. Under the omnibus agreement, OGE Energy, CenterPoint Energy and their affiliates have agreed to hold or otherwise conduct all of their respective midstream operations located within the United States through us. This requirement will cease to apply to both OGE Energy and CenterPoint Energy as soon as either CenterPoint Energy or OGE Energy ceases to hold any interest in our general partner or at least 20% of our common units, and does not apply in certain other circumstances. Please read "Certain Relationships and Related Party Transactions—Omnibus Agreement." In addition, under our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to the general partner and its affiliates. As a result, neither the general partner nor any of its affiliates have any obligation to present business opportunities to us.

Our General Partner is Allowed to Take into Account the Interests of Parties Other Than Us, Such as OGE Energy or Centerpoint Energy, in Resolving Conflicts of Interest.

Our partnership agreement contains provisions that permissibly modify and reduce the 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 relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples of decisions that our general partner may make in its individual capacity include the allocation of corporate opportunities among us and our affiliates (subject to the terms of the omnibus agreement), the exercise of its limited call right or its voting rights with respect to the units it owns, whether 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, consolidation or conversion of the partnership or amendment to the partnership agreement.

We do not have any Officers or Employees and Rely Solely on Officers and Employees of Our General Partner and its Affiliates.

Affiliates of our general partner conduct businesses and activities of their own in which we have no economic interest. There could be material competition for the time and effort of the officers and employees who provide services to our general partner.

All of the initial officers and directors of our general partner are also officers and/or directors of OGE Energy or CenterPoint Energy. These officers will devote such portion of their productive time to our business and affairs as is required to manage and conduct our operations. These officers are also required to devote time to the affairs of OGE Energy or CenterPoint Energy, as applicable, or their subsidiaries and are compensated by them for the services rendered to them. Our non-executive directors devote as much time as is necessary to prepare for and attend board of directors and committee meetings.

Our Partnership Agreement Replaces the Fiduciary Duties that Would Otherwise be Owed by our General Partner with Contractual Standards Governing its Duties and Limits Our General Partner's Liabilities and the Remedies Available to Our Unitholders for 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 remedies available to our limited partners for actions that might constitute breaches of fiduciary duty under applicable Delaware 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. 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 limited partners for decisions made in its capacity so long as such decisions are made in good faith;
- generally provides that in 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 public 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 is either on terms no less favorable to us than those generally being provided to or available from unrelated third parties or is "fair and reasonable" to us, considering the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us, then it will be presumed that in making its decision, the board of directors of our general partner acted in good faith,

and in any proceeding brought by or on behalf of any limited partner or us challenging such decision, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

- provides that our general partner and its 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 officers or directors, as the cases 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.

By purchasing a common unit, a common unitholder will be deemed to have agreed to become bound by the provisions in the partnership agreement, including the provisions discussed above.

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 or exchangeable for equity interests of the partnership and the incurring of any other obligations;
- the making of tax, regulatory and other filings, or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets;
- the acquisition, disposition or exchange of certain of our assets;
- the encumbrance or hypothecation of any or all of our assets;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of cash held by the partnership;
- 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 and indemnitees;
- the formation of, or acquisition of an interest in, and the contribution of property and the making of loans to, any further limited or general partnerships, joint ventures, corporations, limited liability companies or other entities;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;
- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the purchase, sale or other acquisition or disposition of our equity interests, or the issuance of additional options, rights, warrants and appreciation rights relating to our equity interests; 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.

Please read “The Partnership Agreement” for information regarding the voting rights of unitholders.

Actions Taken by Our General Partner May Affect the Amount of Cash Available to Pay Distributions 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:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- 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, equal to $ million, which would not otherwise constitute available cash from operating surplus or capital surplus, in order to permit the payment of cash distributions on its units and incentive distributions rights. All of these actions may affect the amount of cash distributed to our unitholders and our general partner and may facilitate the conversion of subordinated units into common units.

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, but may not lend funds to our general partner or its affiliates.

We Reimburse Our General Partner and its Affiliates for Expenses.

We reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Please read “Certain Relationships and Related Party Transactions—Distributions and Payments to Our General Partner and Its Affiliates.”

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 other party to such agreements has recourse only to our assets and not against our general partner or its assets or any affiliate of our general partner or its assets. Our partnership agreement permits our general partner to limit its or our liability, 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 the partnership agreement or assign this right to one of its affiliates or to us free of any liability or obligation to us or our partners. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read "The Partnership Agreement—Limited Call Right."

Limited Partners 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 hand, will not grant to the limited partners, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

We may Choose not to Retain Separate Counsel, Accountants or Others for Ourselves or for the Holders of Common Units.

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 also 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 hand, 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 Minimum Quarterly Distribution and the Target Distribution Levels Related to Our General Partner's Incentive Distribution Rights Without the Approval of the Conflicts Committee of Our General Partner or Our Unitholders. This 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, it has received incentive distributions at the highest level to which it is entitled (50.0%) for each of the prior four consecutive fiscal quarters and the amount of each such distribution did not exceed the adjusted operating surplus for such quarter, respectively, to reset the initial minimum quarterly distribution and cash target distribution levels at higher levels based on the average cash distribution amount per common unit for the two fiscal quarters prior to the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common 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 amount. 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 be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our 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 new common units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights. Please read "Provisions of Our Partnership Agreement Relating to Cash Distributions—Incentive Distribution Rights."

Duties of the General Partner

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 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 our general partner 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 otherwise might 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. We believe this is appropriate and necessary because the board of directors of our general partner has fiduciary duties to manage our general partner in a manner beneficial both to its owners, OGE Energy and CenterPoint Energy, as well as to our limited partners. Without these provisions, the general partner's ability to make decisions involving conflicts of interests would be restricted. These provisions benefit our general partner by enabling it to take into consideration all parties involved in the proposed action. These provisions also strengthen the ability of our general partner to attract and retain experienced and capable directors. These provisions represent a detriment to the limited partners, however, because they restrict the remedies available to limited partners 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 conflicted interests. 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 referenced in the preceding bullet that would otherwise be imposed by Delaware law on our general partner; and
- certain rights and remedies of limited partners contained in our partnership agreement and the Delaware Act.

Delaware 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 transaction were entirely fair to the partnership. Our partnership agreement modifies these standards as described below.

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. Section 7.9 of 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 free of any duty or obligation whatsoever to us or the limited partners, 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.

Section 7.9 of our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the public common unitholders or the conflicts committee of the board of directors of our general partner must be 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
- "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 public 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 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 board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, 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, its affiliates and their officers and directors will not be liable for monetary damages to us or, our limited partners for losses sustained or liabilities incurred as a result of any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such person 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.

Rights and remedies of limited partners

The Delaware Act favors the principles of freedom of contract and enforceability of partnership agreements and allows the partnership agreement to contain terms governing the rights of the unitholders. The rights of our unitholders, including voting and approval rights and the ability of the partnership to issue additional units, are governed by the terms of our partnership agreement. Please read “The Partnership Agreement.” As to 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 wrongfully 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, if any, 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 to the limited partners.

A transferee of or other person acquiring a common unit will be deemed to have agreed to be bound, by the provisions in the partnership agreement, including the provisions discussed above. Please read “Description of the Common Units—Transfer of Common Units.” 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 our partnership agreement does not render the partnership agreement unenforceable against that person.

Under the 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. We also must provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent that these provisions purport to include indemnification for liabilities arising under the Securities Act of 1933, as amended, or Securities Act, in the opinion of the SEC such indemnification is contrary to public policy and therefore unenforceable. If you have questions regarding the duties of our general partner please read “The Partnership Agreement—Indemnification.”

DESCRIPTION OF THE COMMON UNITS

The Units

The common units and the subordinated units are separate classes of limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or 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 "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 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 unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There will be no charge to unitholders for disbursements of our cash distributions. We will indemnify the transfer agent, its agents and each of their 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 register and such limited partner becomes the record holder of the common units so transferred. Each transferee:

- will become bound and will be deemed to have agreed to be bound by the terms and conditions of our partnership agreement;
- represents that the transferee has the capacity, power and authority to enter into our partnership agreement; and
- makes the consents, acknowledgements and waivers 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

all with or without executing our partnership agreement.

We are entitled to treat the nominee holder of a common unit as the absolute owner in the event such nominee is the record holder of such common unit. 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 transfers of securities. Until a common unit has been transferred on our register, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations. Certain transfers of our units by OGE Energy and CenterPoint Energy are subject to rights of first offer and rights of first refusal. Please read "The Partnership Agreement—Transfer of General Partner Interests."

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 Fiduciary Duties";
- with regard to the transfer of common units, please read "Description of the 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

Our partnership was formed as a limited liability company on December 31, 2010. Our general partner and CenterPoint Energy caused the partnership to be converted from a limited liability company to a limited partnership and adopted the partnership agreement on May 1, 2013. The partnership will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under the partnership agreement is limited to any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided, that our general partner shall not cause us to engage, directly or indirectly, in any business activity that our general partner determines would be reasonably likely to 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 ability to cause us and our subsidiaries to engage in activities other than the business of gathering, processing, transporting and storing natural gas and the gathering of crude oil, 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 the limited partners, including any duty to act in the best interests of us or the limited partners, other than the implied contractual covenant of good faith and fair dealing. Our general partner is authorized in general to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring 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.

In voting their common and subordinated units, our general partner and its affiliates will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners, other than the implied covenant of good faith and fair dealing.

Issuance of additional units	No approval right.
Amendment of the 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 the 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, Consolidation, Conversion, 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 the general partner	Under most circumstances, the approval of unitholders holding at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to in a manner that would cause a dissolution of our partnership. Please read "—Withdrawal or Removal of the General Partner."
Removal of the general partner	Not less than 75% 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 the General Partner."
Transfer of the general partner interest	Our general partner may transfer any or all of its general partner interest in us without a vote of our unitholders but must obtain prior approval of all members of the board of directors. Please read "—Transfer of General Partner Interests."
Transfer of incentive distribution rights	Our general partner may transfer any or all of the incentive distribution rights without a vote of our unitholders. Please read "—Transfer of Incentive Distribution Rights."
Reset of incentive distribution levels	No unitholder approval required.
Transfer of ownership interests in our general partner	No unitholder approval required. Please see "—Transfer of Ownership Interests in the General Partner."

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of the partnership agreement or the duties, obligations or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a duty (including a fiduciary duty) owed by any director, officer, or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other Delaware courts) in connection with any such claims, suits, actions or proceedings.

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, 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 the limited partner is a general partner. Neither the 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 this type of 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 limited partner 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 non-recourse 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 his 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 in several states and we may have subsidiaries that conduct business in other states in the future. Maintenance of our limited liability as a limited partner or member of our operating subsidiaries may require compliance with legal requirements in the jurisdictions in which our operating subsidiaries conduct business, including qualifying our subsidiaries to do business there.

Limitations on the liability of limited partners or members for the obligations of a limited partnership or limited liability company have not been clearly established in many jurisdictions. If, by virtue of our limited partner 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 the 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 Partnership Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership interests. 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 interests 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 interests that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity interests, which may effectively rank senior to the common units.

Each affiliate of 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 interests whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of such person, including such interest represented by common units and subordinated units, that existed immediately prior to each issuance. The other holders of common units will not have preemptive rights to acquire additional common units or other partnership interests.

Amendment of the 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 the limited partners, including any duty to act in the best interests of us or the limited partners, other than the implied contractual covenant of good faith and fair dealing. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to 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 it is deemed to have occurred as a result of an amendment 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 its consent, which consent may be given or withheld at its option.

The provisions of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates). Upon completion 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 office, 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 to qualify or 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 nor any of our 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 any other changes that our general partner determines to be necessary or appropriate as a result of such change;
- 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, as amended, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed by the U.S. Department of Labor;
- an amendment that our general partner determines to be necessary or appropriate for the authorization or issuance of additional partnership interests;
- 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 to reflect and account for the formation by us of, or our investment in, any corporation, partnership or other entity, in connection with our conduct of activities permitted by our partnership agreement;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses 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 limited partner interests (including the division of any class or classes of outstanding units into different classes to facilitate uniformity of tax consequence within such class of units) or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed or admitted to 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 Unitholder Approval

Amendments to our partnership agreement that require unitholder approval will require the approval of holders of at least 90% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that an amendment will not affect the limited liability of any limited partner under Delaware law. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain such an opinion.

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 partnership interests in relation to other classes of partnership interests will require the approval of at least a majority of the type or class of partnership interests so affected. Any amendment that would reduce the percentage of units required to take any action, other than to remove our general partner or call a meeting of unitholders, must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be reduced. Any amendment that would increase the percentage of units required to remove our general partner must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than 90% of outstanding units. Any amendment that would increase the percentage of units required to call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute at least a majority of the outstanding units.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion 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, consolidation or conversion 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 the limited partners, other than the implied contractual covenant of good faith and fair dealing.

In addition, the 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 assets in a single transaction or a series of related transactions. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell any or all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger with another limited liability entity 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 an amendment to the partnership agreement requiring unitholder approval, each of our units will be an identical unit of our partnership following the transaction, and the partnership interests to be issued by us in such merger do not exceed 20% of our outstanding partnership interests immediately prior to the transaction.

If the conditions specified in the 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 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 general partner determines that the governing instruments of the new entity provide the limited partners and the general partner with the same rights and obligations as contained in the partnership agreement. The unitholders are not entitled to dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of all or substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until dissolved and terminated under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or
- 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 followed by approval and admission of a successor.

Upon a dissolution under the last 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 by appointing 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 our partnership 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.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a new 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 or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of the General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to 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 , our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written 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% of the outstanding units are held or controlled by one person and its affiliates other than the general partner and its affiliates. In addition, the partnership agreement permits the general partner to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Interests" and "—Transfer of Incentive Distribution Rights."

Upon voluntary withdrawal of our general partner by giving written notice to the other partners, 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 after that withdrawal, the holders of a unit majority agree to continue our business by appointing a successor general partner. Please see "—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 75% of the 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 voting as a separate class, and subordinated units, voting as a separate class. The ownership of more than 25% of the outstanding units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal. At the closing of this offering, affiliates of our general partner will own approximately % 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 and units held by the general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end, and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- 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 based on the fair market value of those interests as of the effective date of its removal.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a 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 a 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 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 will become a limited partner and its general partner interest and its incentive distribution rights will automatically convert into common units pursuant to a valuation 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 the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interests

Our general partner may transfer all or any of its general partner interest without the approval of our unitholders, but any such transfer requires the approval of all members of the board of directors. As a condition of this transfer, the transferee must assume, among other things, 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.

Each of OGE Energy and CenterPoint Energy has a right of first offer and a right of first refusal with respect to proposed sales by the other party of 5% or more of such party’s common units or subordinated units.

Transfer of Ownership Interests in the General Partner

OGE Energy or CenterPoint Energy and their subsidiaries may sell or transfer all or part of their membership interest in our general partner to an affiliate or third party without the approval of our unitholders; provided that each of OGE Energy and CenterPoint Energy have rights of first offer and rights of first refusal with respect to proposed sales by the other party of all, but not less than all, of such party’s membership interest. Sales or transfers of membership interests in our general partner prior to that time are prohibited by our general partner’s limited liability company agreement.

Transfer of Incentive Distribution Rights

At any time, our general partner may transfer its incentive distribution rights to an affiliate or third party without the approval of our unitholders.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Enable GP, LLC as our general partner or otherwise change our management. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% 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 from our general partner or its affiliates and any transferees of that person or group who are notified by our general partner that they will not lose their voting rights or to any person or group who acquires the units with the prior approval of the board of directors of our general partner.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- 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 units and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests as of the effective date of its removal.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% 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 limited partner interests of such 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 cash price paid by either of 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 current market price calculated in accordance with our partnership agreement as of the date three business 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 a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. 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% or more of any class of units then outstanding, 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.

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, if authorized by our general partner, without a meeting if consents in writing describing the action so taken are signed by holders of the number of units that would be necessary to authorize or take that action at a meeting where all limited partners were present and voted. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% 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.

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 Partnership Interests." However, if at any time any person or group, other than our general partner and its affiliates, a direct transferee of our general partner and its affiliates or a transferee of such direct transferee who is notified by our general partner that it will not lose its voting rights, acquires, in the aggregate, beneficial ownership of 20% 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 shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our register. Except as described under "—Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Ineligible Holders; Redemption

Under our partnership agreement, an "Eligible Holder" is a limited partner whose (a) federal income tax status is not reasonably likely to have a material adverse effect on the rates that can be charged by us on assets that are subject to regulation by FERC or an analogous regulatory body and (b) nationality, citizenship or other related status would not create a substantial risk of cancellation or forfeiture of any property in which we have an interest, in each case as determined by our general partner with the advice of counsel.

If at any time our general partner determines, with the advice of counsel, that one or more limited partners are not Eligible Holders (any such limited partner, an Ineligible Holder), then our general partner may request any limited partner to furnish to the general partner an executed certification or other information about his federal income tax status and/or nationality, citizenship or related status. If a limited partner fails to furnish such certification or other requested information within 30 days (or such other period as the general partner may determine) after a request for such certification or other information, or our general partner determines after receipt of the information that the limited partner is not an Eligible Holder, the limited partner may be treated as an Ineligible Holder. An Ineligible Holder does not have the right to direct the voting of his units and may not receive distributions in kind upon our liquidation.

Furthermore, we have the right to redeem all of the common and subordinated units of any holder that our general partner concludes is an Ineligible Holder or fails to furnish the information requested by our general partner. The redemption price in the event of such redemption for each unit held by such unitholder will be the current market price of such unit (the date of determination of which shall be the date fixed for redemption). The redemption price will be paid, as determined by our general partner, in cash or by delivery of a promissory note. Any such promissory note will bear interest at the rate of 5.0% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, 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 a general partner or any departing general partner;
- any person who is or was a director, officer, managing member, manager, general partner, fiduciary or trustee of our subsidiaries, us or any entity set forth in the preceding three bullet points;
- any person who is or was serving as director, officer, managing member, manager, general partner, fiduciary or trustee of another person owing a fiduciary duty to us or any of our subsidiaries at the request of our general partner or any departing general partner or any of their affiliates; 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 lend funds or assets to us to enable us to effectuate, indemnification. We will 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 such liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all 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 payments and expenses include salary, bonus, incentive compensation and other amounts paid to any person who is an employee of our general partner and manages our business and affairs and overhead and general and administrative expenses allocated to our general partner by its affiliates. The general partner is entitled to determine in good faith the expenses that are allocable to us. Please read “Certain Relationships and Related Party Transactions—Omnibus Agreement.”

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books will be maintained for financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will mail or make available to record holders of common units, within 105 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. Except for our fourth quarter, we will also mail or make available summary financial information within 50 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for 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 his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement and our certificate of limited partnership and all amendments thereto; and
- certain information regarding the status of our business and financial condition.

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 in good faith believes is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the right to information that a limited partner would otherwise have under Delaware law.

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of the common units offered hereby, CenterPoint Energy will hold an aggregate of common units and subordinated units, OGE Energy will hold an aggregate of common units and subordinated units, and ArcLight will hold an aggregate of common units. All of the subordinated units will convert into common units at the end of the subordination period. The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop. As explained above under the caption "Certain Relationships and Related Party Transactions—Registration Rights Agreement," affiliates of OGE Energy, CenterPoint Energy and ArcLight have specified demand and piggyback registration rights with respect to the common units they own.

All of the common units and subordinated units held by CenterPoint Energy, OGE Energy and ArcLight are subject to the lock-up restrictions described below and under the heading "Underwriting." The sale of these units could have an adverse impact on the price of the common units or on any trading market that may develop.

Rule 144

The common units sold in this offering will generally be freely transferable without restriction or further registration under the Securities Act. None of the directors or officers of our general partner own any common units prior to this offering. Any common units owned 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; and
- 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 90 days 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 those common units under Rule 144 without regard to the volume limitations, manner of sale provisions and notice requirements of Rule 144.

Our Partnership Agreement

Our partnership agreement provides that we may issue an unlimited number of partnership interests of any type without a vote of the unitholders. Any issuance of additional common units or other equity interests 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 Partnership Interests."

Registration Rights Agreement

Pursuant to a registration rights agreement we entered into with affiliates of OGE Energy, CenterPoint Energy and ArcLight, those affiliates have specified demand and piggyback registration rights with respect to the registration and sale of their common units. In particular, beginning 180 days after the closing of this offering, affiliates of OGE Energy and CenterPoint Energy will each have the right to cause us to prepare and file a registration statement with the SEC covering the offering and sale of their common units. At any time following the time when we are eligible to file a registration statement on Form S-3, ArcLight will have the right to cause us to prepare and file a registration statement on Form S-3 with the SEC covering the offering and sale of its common units. We are not obligated to effect more than (i) three such demand registrations for OGE Energy and CenterPoint combined, or (ii) two such demand registrations (and no more than one in any twelve-month period) for ArcLight. If we propose to file a registration statement (other than pursuant to a demand registration discussed above, or other than for an employee benefit plan), OGE Energy, CenterPoint Energy and/or ArcLight may request to "piggyback" onto such registration statement in order to offer and sell their common units.

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 certain 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. Our affiliates may also sell their units or other partnership interests in private transactions at any time, subject to compliance with applicable laws and the lock-up agreement described below and under the heading "Underwriting."

Lock-Up Agreements

We, CenterPoint Energy, OGE Energy, ArcLight, our general partner and the directors and executive officers of our general partner have agreed, subject to certain exceptions, not to sell or offer to sell any common units for a period of 180 days from the date of this prospectus. For a description of these lock-up provisions, please read "Underwriting."

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 United States and, unless otherwise noted in the following discussion, is the opinion of Baker Botts L.L.P., 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, or the Code, existing and proposed Treasury regulations promulgated under the Code, or 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 Enable Midstream Partners, LP 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 United States and has only limited application to corporations, estates, trusts, partnerships and entities treated like partnerships for federal income tax purposes, 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), employee benefit plans 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, and does not comment on local, or foreign, tax consequences. Accordingly, we encourage each prospective unitholder to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Baker Botts L.L.P. and are based on the accuracy of the representations made by us.

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 Baker Botts L.L.P. 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 distributable cash flow 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.

For the reasons described below, Baker Botts L.L.P. 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 (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. Pursuant to Code Section 731, 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 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 90.0% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and other 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, Baker Botts L.L.P. is of the opinion that at least 90.0% 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 Code. Instead, we will rely on the opinion of Baker Botts L.L.P. on such matters. It is the opinion of Baker Botts L.L.P. that, based upon the 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 or will be treated as a partnership for federal income tax purposes.

In rendering its opinion, Baker Botts L.L.P. has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Baker Botts L.L.P. has relied include, without limitation:

- Neither we nor the operating subsidiaries has elected or will elect to be treated as a corporation; and
- For every taxable year, more than 90.0% of our gross income has been and will be income of the type that Baker Botts L.L.P. has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the 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 for federal income tax purposes 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, pursuant to Code Section 301, 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 Baker Botts L.L.P.'s opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders who are admitted as limited partners of Enable Midstream Partners, LP will be treated as partners of Enable Midstream Partners, LP 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 Enable Midstream Partners, LP 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 be fully taxable as ordinary income. These holders are urged to consult their own tax advisors with respect to the tax consequences of holding common units in Enable Midstream Partners, LP. The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Enable Midstream Partners, LP 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. The income we allocate to unitholders will generally be taxable as ordinary income. 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.

Treatment of Distributions

Pursuant to Code Section 731, 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. Cash distributions made by us to a unitholder in an amount 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" below. Any reduction in a unitholder's share of our liabilities for which no partner, including the

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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, Section 465 of the Code requires the recapture of 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 under Section 752 of the Code, 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 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 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 , 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. However, the ratio of taxable income to distributions for any single year in the projection period may be higher or lower. Thereafter, we anticipate that the ratio of 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 ratio of taxable income to cash distributions 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 taxable income to cash distributions to a purchaser of common units in this offering will be higher, and perhaps substantially higher, 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 this 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 determined under Sections 722, 742 and 752 of the Code and will generally equal the amount he paid for the common units plus his share of our nonrecourse liabilities. That basis will be increased under Section 705 of the Code by his share of our income and by any increases in his share of our nonrecourse liabilities and 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 Treasury Regulations under Section 752 of the 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

Under Sections 704 and 465 of the Code, 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 50.0% 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 another 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 of Code Section 469 generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally defined as 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 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

Section 163 of the Code generally limits the deductibility of a non-corporate taxpayer's "investment interest expense" 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 in Notice 88-75, 1988-2 C.B. 386, 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, under Section 704 of the Code, 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 those 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 as adjusted for certain items in accordance with applicable Treasury Regulations and, second, to our general partner.

Section 704(c) of the Code requires us to assign each asset contributed to us in connection with this offering a "book" basis equal to the fair market value of the asset at the time of this offering. Purchasers of units in this offering are entitled to calculate tax depreciation and amortization deductions and other relevant tax items with respect to our assets based upon that "book" basis, which effectively puts purchasers in this offering in the same position as if our assets had a tax basis equal to their fair market value at the time of this offering. In this context, we use the term "book" as that term is used in Treasury regulations under Section 704 of the Code. The "book" basis assigned to our assets for this purpose may not be the same as the book value of our property for financial reporting purposes.

Upon any issuance of units by us after this offering, rules similar to those of Section 704(c) described above will apply for the benefit of recipients of units in that later issuance. This may have the effect of decreasing the amount of our tax depreciation or amortization deductions thereafter allocated to purchasers of units in this offering or of requiring purchasers of units in this offering to thereafter recognize "remedial income" rather than depreciation and amortization deductions.

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 under the Section 704(c) principles described above, 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 interests of all the partners in cash flows; and
- the rights of all the partners to distributions of capital upon liquidation.

Baker Botts L.L.P. is of the opinion that, with the exception of the issues described in "—Section 754 Election," "—Disposition of Common Units—Allocations Between Transferors and Transferees," and "—Uniformity of Units," allocations under our partnership agreement will be given effect under Section 704 of the Code 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.

Because there is no direct or indirect controlling authority on the issue relating to partnership interests, Baker Botts L.L.P. 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 in the preamble to certain temporary regulations, 53 Fed. Reg. 34488-01, 1988-2 C.B. 346, 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 26.0% on the first $179,500 of alternative minimum taxable income in excess of the exemption amount and 28.0% 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

The highest marginal U.S. federal income tax rates applicable to ordinary income and long-term capital gains (generally, capital gains on certain assets held for more than twelve months) of individuals currently are 39.6% and 20.0%, respectively. These rates are subject to change by new legislation at any time.

Section 1411 of the Code imposes 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 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, or inside basis, under Section 743(b) of the Code to reflect his purchase price. This election does not apply with respect to a person who purchases common units directly from us, including a purchaser of units in this offering. 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, or common basis, and (ii) his Section 743(b) adjustment to that basis.

The timing of deductions attributable to a Section 743(b) adjustment to our common basis will depend upon a number of factors, including the nature of the assets to which the adjustment is allocable, the extent to which the adjustment offsets any Section 704(c) type gain or loss with respect to an asset and certain elections we make as to the manner in which we apply Section 704(c) principles with respect to an asset with respect to which the adjustment is allocable. Please read "—Allocation of Income, Gain, Loss and Deduction." The timing of these deductions may affect the uniformity of our units. Please read "—Uniformity of Units."

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.

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 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. Under Section 704 of the Code, 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. Part or all of the goodwill, going concern value and other intangible assets we acquire in connection with this offering may not produce any amortization deductions because of the application of the anti-churning restrictions of Section 197 of the Code. Please read "—Uniformity of Units." Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the 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 under Section 1245 or Section 1250 of the Code 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 under Section 709 of the Code 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 20.0%. 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 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 each year, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS ruled in Rev. Rul. 84-53,1984-1 C.B. 159, 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 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. 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.

Section 1259 of the Code can 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 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, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations under Section 706 of the Code 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. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. 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, Baker Botts L.L.P. 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 future Treasury Regulations.

A unitholder who disposes of units prior to the record date set for a cash distribution for any quarter will be allocated items of our income, gain, loss and deductions attributable to the month of sale but will not be entitled to receive that cash distribution.

Notification Requirements

A unitholder who sells any of his units is generally required by regulations under Section 6050K of the Code 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 under Section 743 of the Code 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 sale may lead to the imposition of penalties under Section 6723 of the Code. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker who will satisfy such requirements.

Constructive Termination

We will be considered under Section 708 of the Code to have terminated our tax partnership for federal income tax purposes upon the sale or exchange of our interests that, in the aggregate, constitute 50.0% or more of the total interests in our capital and profits within a twelve-month period. Immediately following this offering, OGE Energy, CenterPoint and ArcLight will in the aggregate indirectly own more than 50.0% of the total interests in our capital and profits. Therefore, transfers and transfers deemed to occur for tax purposes by OGE Energy, CenterPoint or ArcLight of all or a portion of their respective interests in us could result in a termination of our partnership for federal income tax purposes. For purposes of measuring whether the 50.0% 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 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 in an Industry Director Communication, LMSB-04-0210-006, a 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. Any non-uniformity could have an impact upon the value of our units. The timing of deductions attributable to Section 743(b) adjustments to the common basis of our assets with respect to persons purchasing units from another unitholder may affect the uniformity of our units. Please read "—Tax Consequences of Unit Ownership—Section 754 Election."

For example, some types of depreciable assets are not subject to the typical rules governing depreciation (under Section 168 of the Code) or amortization (under Section 197 of the Code). If we were to acquire any assets of that type, the timing of a unit purchaser's deductions with respect to Section 743(b) adjustments to the common basis of those assets might differ depending upon when and to whom the unit he purchased was originally issued. We do not currently expect to acquire any assets of that type. However, if we were to acquire a material amount of assets of that type, we intend to adopt tax positions as to those assets that will not result in any such lack of uniformity. Any such tax positions taken by us might result in allocations to some unitholders of smaller depreciation deductions than they would otherwise be entitled to receive. Baker Botts L.L.P. has not rendered an opinion with respect to those types of tax positions. Moreover, the IRS might challenge those tax positions. If we took such a tax position and the IRS successfully challenged the position, the uniformity of our units might be affected, and the gain from the sale of our 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 under Section 511 of the Code 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. Please read "Investment in Enable Midstream Partners, LP by Employee Benefit Plans."

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered under Section 875 of the Code to be engaged in business in the United States 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, we will withhold at the highest applicable effective tax rate from cash distributions made quarterly to foreign unitholders. 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 under Section 884 of the Code at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which 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 United States 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 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 Rev. Rul. 91-32, 1991-1 C.B. 107, interpreting the scope of "effectively connected income," a foreign unitholder would be considered to be engaged in a trade or business in the United States 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 5.0% of our common units at any time during the five-year period ending on the date of such disposition and (ii) 50.0% 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 50.0% 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 taxable 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 Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Baker Botts L.L.P. 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 under Section 6221 of the Code 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 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 1.0% 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 1.0% 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 pursuant to Section 6222 of the Code 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.

Additional Withholding Requirements

Under recently enacted legislation, the relevant withholding agent may be required to withhold 30.0% of any interest, dividends and other fixed or determinable annual or periodical gains, profits and income from sources within the United States (FDAP Income) or gross proceeds from the sale of any property of a type which can produce interest or dividends from sources within the United States paid to (i) a foreign financial institution (for which purposes includes, among other entities, foreign broker-dealers, clearing organizations, investment companies, hedge funds and certain other investment entities) unless such foreign financial institution agrees to verify, report and disclose its U.S. accountholders and meets certain other specified requirements or (ii) a non-financial foreign entity that is a beneficial owner of the payment unless such entity certifies that it does not have any substantial U.S. owners or provides the name, address and taxpayer identification number of each substantial U.S. owner and such entity meets certain other specified requirements or otherwise qualifies for an exemption from this withholding. These rules will generally apply to payments of FDAP Income which are made after June 30, 2014, and to payments of relevant gross proceeds which are made after December 31, 2016. Non-U.S. and U.S. unitholders are encouraged to consult their own tax advisors regarding the possible implications of this legislation on their investment in our common units.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required under Section 6031 of the Code to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- a statement regarding whether the beneficial owner is:
  - a person that is not a U.S. person;
  - a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or
  - 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 sales.

Brokers and financial institutions are required under Section 6031 of the Code 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 $1.5 million per calendar year, is imposed by Section 6722 of the 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 20.0% 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 under Section 6662 of the 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 10.0% 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 150.0% 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 Section 482 of the Code is 200.0% or more (or 50.0% or less) of the amount determined under Code Section 482 to be the correct amount of such price, or (c) the net Section 482 transfer price adjustment for the taxable year exceeds the lesser of $5 million or 10.0% 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 200.0% or more than the correct valuation or certain other thresholds are met, the penalty imposed increases to 40.0%. We do not anticipate making any valuation misstatements.

In addition, the 20.0% 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 40.0%. 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 under Treasury regulations under Section 6011 of the Code and related provisions 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 6 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 provisions of the American Jobs Creation Act of 2004:

- 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."

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. We currently do business or own property in several states, most of which impose personal income taxes on individuals. Most of these states also impose an income tax on corporations and other entities. Moreover, we may also own property or do business in other states in the future that impose income or similar taxes on nonresident individuals. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. A unitholder may 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 jurisdictions, of his investment in us. Accordingly, each prospective unitholder is urged to consult, and depend upon, his 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. Baker Botts L.L.P. has not rendered an opinion on the state, local or foreign tax consequences of an investment in us.

INVESTMENT IN ENABLE MIDSTREAM PARTNERS, LP 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. restrictions imposed by Section 4975 of the Code, and provisions under any federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the 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 individual retirement accounts or annuities, or IRAs, 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. 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, that plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws; and
- 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 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 or IRA.

Section 406 of ERISA and Section 4975 of the Code prohibit employee benefit plans, and also IRAs that are not considered part of an employee benefit plan, from engaging in specified transactions involving "plan assets" with parties that are "parties in interest" under ERISA or "disqualified persons" under the Code with respect to the plan 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 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 Code.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that the general partner would also be a fiduciary of such 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 Code, ERISA, and any other applicable Similar Laws.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets would not be considered to be "plan assets" if, among other things:

(1) the equity interests acquired by employee benefit plans are publicly offered securities (i.e., the equity interests are widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under certain provisions of the federal securities laws);

(2) 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

(3) 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 certain interests held by our general partner, its affiliates, and certain other persons) is held by the employee benefit plans referred to above, and IRAs that are subject to ERISA and/or Section 4975 of the Code.

With respect to an investment in our common units, we believe that our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in (1) and (2) above.

The foregoing discussion of issues arising for employee benefit plan investments under ERISA, the Code, and applicable Similar Laws is general in nature and is not intended to be all-inclusive, nor should it be construed as legal advice. Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA, the Code and other Similar Laws in light of the complexity of these rules and the serious penalties that may be imposed on persons who engage in prohibited transactions or other violations.

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UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated the date of this prospectus, the underwriters named below, for whom Morgan Stanley & Co. LLC, Barclays Capital Inc. and Goldman, Sachs & Co. are acting as representatives, have severally agreed to purchase, and we have agreed to sell to them, severally, the number of common units indicated below:

Name	Number of Common Units
Morgan Stanley & Co. LLC	
Barclays Capital Inc.	
Goldman, Sachs & Co.	
Total:	

The underwriters and the representatives are collectively referred to as the "underwriters" and the "representatives," respectively. The underwriters are offering the common units subject to their acceptance of the common units from us and subject to prior sale. The underwriting agreement provides that the obligations of the several underwriters to pay for and accept delivery of the common units offered by this prospectus are subject to the approval of certain legal matters by their counsel and to certain other conditions. The underwriters are obligated to take and pay for all of the common units offered by this prospectus if any such common units are taken. However, the underwriters are not required to take or pay for the common units covered by the underwriters' option to purchase additional common units described below.

The underwriters initially propose to offer part of the common units directly to the public at the public offering price listed on the cover page of this prospectus and part to certain dealers at that price less a selling concession not in excess of $ per common unit. The underwriters may allow, and such dealers may reallow, a concession not in excess of $ per common unit to other dealers. After the initial offering of the common units, the offering price and other selling terms may from time to time be varied by the representatives.

We have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to an aggregate of additional common units at the public offering price listed on the cover page of this prospectus, less underwriting discounts and commissions. The underwriters may exercise this option solely for the purpose of covering over-allotments, if any, made in connection with the offering of the common units offered by this prospectus. To the extent the option is exercised, each underwriter will become obligated, subject to certain conditions, to purchase about the same percentage of the additional common units as the number listed next to the underwriter's name in the preceding table bears to the total number of common units listed next to the names of all underwriters in the preceding table.

The following table shows the per unit and total public offering price, underwriting discounts and commissions, and proceeds before expenses to us. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase up to an additional common units.

		Total	
	Per Common Units	No Exercise	Full Exercise
Public offering price	$	$	$
Underwriting discounts and commissions to be paid by us			
Proceeds, before expenses, to us	$	$	$

The estimated offering expenses payable by us, exclusive of the underwriting discounts and commissions, are approximately $.

The underwriters have informed us that they do not intend sales to discretionary accounts to exceed 5% of the total number of common units offered by them.

We have applied to list our common units on the NYSE under the symbol "ENBL."

We, CenterPoint Energy, OGE Energy, ArcLight, our general partner and our general partner's directors and executive officers have agreed that, without the prior written consent of Morgan Stanley & Co. LLC on behalf of the underwriters, and subject to specified exceptions, we and they will not, during the period ending 180 days after the date of this prospectus (the "restricted period"):

- offer, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend or otherwise transfer or dispose of, directly or indirectly, any common units or any securities convertible into or exercisable or exchangeable for common units;
- file any registration statement with the SEC relating to the offering of any common units or any securities convertible into or exercisable or exchangeable for common units; or
- enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the common units;

whether any such transaction described above is to be settled by delivery of common units or such other securities, in cash or otherwise. In addition, we and each such person agrees that, without the prior written consent of Morgan Stanley & Co. LLC on behalf of the underwriters, we or such other person will not, during the restricted period, make any demand for, or exercise any right with respect to, the registration of any common units or any security convertible into or exercisable or exchangeable for common units.

The restrictions described in the immediately preceding paragraph do not apply to:

- the sale of common units to the underwriters; or
- the issuance by us of common units upon the exercise of an option or a warrant or the conversion of a security outstanding on the date of this prospectus of which the underwriters have been advised in writing; or
- the establishment of a trading plan pursuant to Rule 10b5-1 under the Exchange Act for the transfer of common units, provided that (i) such plan does not provide for the transfer of common units during the restricted period and (ii) to the extent a public announcement or filing under the Exchange Act, if any, is required of or voluntarily made regarding the establishment of such plan, such announcement or filing shall include a statement to the effect that no transfer of common units may be made under such plan during the restricted period.

If:

- during the last 17 days of the restricted period we issue an earnings release or material news event relating to us occurs, or
- prior to the expiration of the restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the restricted period or provide notification to Morgan Stanley & Co. LLC of any earnings release or material news or material event that may give rise to an extension of the initial restricted period,

then the restrictions described above will 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.

Morgan Stanley & Co. LLC, in its sole discretion, may release the common units and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice.

In order to facilitate the offering of the common units, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the common units. Specifically, the underwriters may over-allot in connection with the offering, creating a short position in the common units for their own account. In addition, to cover over-allotments or to stabilize the price of the common units, the underwriters may bid for, and purchase, common units in the open market. Finally, the underwriting syndicate may reclaim selling concessions allowed to an underwriter or a dealer for distributing the common units in the offering, if the syndicate repurchases previously distributed common units in transactions to cover syndicate short positions, in stabilization transactions or otherwise. Any of these activities may stabilize or maintain the market price of the common units above independent market levels. The underwriters are not required to engage in these activities, and may end any of these activities at any time.

We and the underwriters have agreed to indemnify each other against certain liabilities, including liabilities under the Securities Act. Because the Financial Industry Regulatory Authority, or FINRA, views the common units offered under this prospectus as interests in a direct participation program, this offering is being made in compliance with Rule 2310 of the FINRA conduct rules. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for quotation on a national securities exchange.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various financial advisory, investment banking, commercial banking and other services for us and our general partner, for which they received or will receive customary fees and expenses. Certain affiliates of Morgan Stanley & Co. LLC, Barclays Capital Inc. and Goldman, Sachs & Co. are lenders under our revolving credit facility and will receive a portion of the net proceeds from this offering. For a description of our revolving credit facility, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving Credit Facility." In addition, affiliates of Morgan Stanley & Co. LLC, Barclays Capital Inc. and Goldman, Sachs & Co. are lenders under our term loan facility.

Furthermore, certain of the underwriters and their respective affiliates may, from time to time, enter into arms-length transactions with us in the ordinary course of their business. 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 (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities or instruments of the partnership. The underwriters and their respective affiliates may also make investment recommendations or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long or short positions in such securities and instruments.

A prospectus in electronic format may be made available on websites maintained by one or more underwriters, or selling group members, if any, participating in this offering. The representatives may agree to allocate a number of common units to underwriters for sale to their online brokerage account holders. Internet distributions will be allocated by the representatives to the underwriters that may make Internet distributions on the same basis as other allocations.

Pricing of the Offering

Prior to this offering, there has been no public market for our common units. The initial public offering price was determined by negotiations between us and the representatives. Among the factors considered in determining the initial public offering price were our future prospects and those of our industry in general, our sales, earnings and certain other financial and operating information in recent periods, and the price-earnings ratios, price-sales ratios, market prices of securities and certain financial and operating information of companies engaged in activities similar to ours.

We cannot assure you that the prices 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.

Selling Restrictions

European Economic Area

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State) an offer to the public of any common units may not be made in that Relevant Member State, except that an offer to the public in that Relevant Member State of any common units may be made at any time under the following exemptions under the Prospectus Directive, if they have been implemented in that Relevant Member State:

(a) to any legal entity which is a qualified investor as defined in the Prospectus Directive;

(b) 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 representatives for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive, provided that no such offer of common units shall result in a requirement for the publication by us or any underwriter of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an "offer to the public" in relation to any common units 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 any common units to be offered so as to enable an investor to decide to purchase any common units, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State, 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 the expression "2010 PD Amending Directive" means Directive 2010/73/EU.

United Kingdom

Each underwriter has represented 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 the FSMA) received by it in connection with the issue or sale of the common units in circumstances in which Section 21(1) of the FSMA does not apply to us; and

(b) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the common units in, from or otherwise involving the United Kingdom.

Hong Kong

The common units may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance

(Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a “prospectus” within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the common units may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to common units which are or are intended to be disposed of only to persons outside Hong Kong or only to “professional investors” within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the common units may not be circulated or distributed, nor may the common units be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore, or the SFA, (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the common units are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire common unit capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, common units, debentures and units of common units and debentures of that corporation or the beneficiaries’ rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the common units under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

Japan

The common units have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and each underwriter has agreed that it will not offer or sell any common units, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

Switzerland

This prospectus is being communicated in Switzerland to a small number of selected investors only. Each copy of this prospectus is addressed to a specifically named recipient and may not be copied, reproduced, distributed or passed on to third parties. Our common units are not being offered to the public in Switzerland, and neither this prospectus, nor any other offering materials relating to our common units may be distributed in connection with any such public offering. We have 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, our common units may not be offered to the public in or from Switzerland, and neither this prospectus, nor any other offering materials relating to our common units may be made available through a public offering in or from Switzerland. Our 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).

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 our common units in Germany. Consequently, our 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 our common units to the public in Germany or any other means of public marketing. Our 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.

LEGAL MATTERS

The validity of the common units will be passed upon for us by Baker Botts L.L.P., Houston, Texas, and Jones Day, Chicago, Illinois. Certain tax matters in connection with the common units offered hereby will be passed upon for us by Baker Botts L.L.P. Certain legal matters in connection with the common units offered hereby will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas.

EXPERTS

The combined financial statements of Enable Midstream Partners, LP and related companies, which comprise the combined balance sheets as of December 31, 2012 and 2011, and the related statements of combined income, comprehensive income, cash flows, and parent net equity for each of the three years in the period ended December 31, 2012, and the related notes to the combined financial statements included herein have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein. Such financial statements are included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

The consolidated financial statements of Enogex LLC, which comprise the consolidated balance sheets and statements of capitalization as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows and changes in member's interest for each of the three years in the period ended December 31, 2012, and the related notes to the consolidated financial statements included herein have been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing herein. Such financial statements are included in reliance upon the report 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-l 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 by this prospectus, you may desire to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330.

The SEC maintains a website on the Internet at *www.sec.gov*. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's website and can also be inspected and copied at the offices of the NYSE Euronext, 11 Wall Street, New York, New York 10005.

You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized any other person to provide you with 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 an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus only. Our business, financial condition, results of operations and prospects may have changed since that date.

Upon completion of this 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 on the Internet is located at *www.   .com*, and we will 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 and 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.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Some of the information in this prospectus may contain forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as "could," "will," "should," "may," "assume," "forecast," "position," "predict," "strategy," "expect," "intend," "plan," "estimate," "anticipate," "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this prospectus include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this prospectus. Those risk factors and other factors noted throughout this prospectus could cause our actual results to differ materially from those disclosed in any forward-looking statement. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by our customers and competitors;
- the demand for natural gas, NGLs, crude oil and midstream services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- operating hazards and other risks incidental to transporting, storing and gathering crude oil and refined products;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;

- large customer defaults;
- changes in the availability and cost of capital;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- changes in insurance markets impacting costs and the level and types of coverage available;
- the timing and extent of changes in commodity prices;
- the suspension, reduction or termination of our customers' obligations under our commercial agreements;
- disruptions due to equipment interruption or failure at our facilities, or third-party facilities on which our business is dependent;
- the effects of future litigation; and
- other factors discussed elsewhere in this prospectus.

Forward-looking statements speak only as of the date on which they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

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ENABLE MIDSTREAM PARTNERS, LP

INTRODUCTION TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

The following unaudited pro forma condensed combined financial statements of Enable Midstream Partners, LP (Partnership) for the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, and as of September 30, 2013 should be read in conjunction with the accompanying notes, as well as the Partnership's historical combined and consolidated financial statements and notes thereto. For accounting and financial reporting purposes, (i) the formation of the Partnership as a limited partnership on May 1, 2013 is considered a contribution by CenterPoint Energy, Inc. (CenterPoint Energy) and is reflected at CenterPoint Energy's historical cost as of May 1, 2013 and (ii) the Partnership is deemed to have acquired Enogex LLC (Enogex) on May 1, 2013.

The pro forma adjustments, as discussed in detail in Note 2—Pro forma adjustments, only give effect to events that are (1) directly attributable to the transactions; (2) factually supportable; and (3) expected to have a continuing effect on the consolidated results of the Partnership. The adjustments are based upon currently available information and certain estimates and assumptions; therefore, actual adjustments will differ from the pro forma adjustments. However, management believes that the assumptions provide a reasonable basis for presenting the significant effects of the contemplated transactions and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied on the pro forma condensed combined financial information. These transactions include, and the pro forma financial data gives effect to, the following:

- The acquisition of Enogex on May 1, 2013, including (1) the incremental depreciation and amortization incurred on the fair value adjustment of Enogex's assets, (2) adjustments to revenue and cost of sales to reflect purchase price adjustments for the recurring impact of certain loss contracts and deferred revenues and (3) a reduction to interest expense for recognition of a premium on Enogex's fixed rate senior notes;
- A reduction in the historical interest income received on the notes receivable—affiliated companies from CenterPoint Energy, which were paid off at formation, and the interest expense incurred on notes payable—affiliated companies to CenterPoint Energy and OGE Energy prior to May 1, 2013, which were repaid at formation;
- The entrance into a $1.05 billion 3-year senior unsecured loan facility (Term Loan Facility) by the Partnership and the incremental interest expense and amortization of deferred financing costs related thereto;
- The entrance into a $1.4 billion senior unsecured revolving credit facility (Revolving Credit Facility) by the Partnership and the incremental interest expense and amortization of deferred financing costs related thereto;
- A reduction for the elimination of federal and state income taxes, except for Texas state margin taxes;
- A reduction in the Partnership's interest in Southeast Supply Header, LLC (SESH) from 50% to 24.95% as of May 1, 2013;
- The consummation of this offering and our issuance of common units to the public and the conversion of common units of CenterPoint Energy and common units of OGE Energy into subordinated units; and
- The application of the net proceeds of this offering as described in "Use of Proceeds".

The pro forma financial data does not give effect to the approximately $3 million in incremental annual operation and maintenance expense we expect to incur as a result of being a publicly traded partnership. The unaudited pro forma adjustments do not give effect to any potential cost savings or other operating efficiencies from the integration of the Partnership and Enogex. The pro forma financial data does not reflect adjustments for the execution of service agreements with CenterPoint Energy and OGE Energy upon formation since the costs under these service agreements were previously incurred by the Partnership and Enogex on a similar basis. The pro forma financial data do not adjust for acquisition related costs since the Partnership incurred no acquisition related costs in the Condensed Combined and Consolidated Income Statement based upon the terms in the master formation agreement.

The Unaudited Pro Forma Condensed Combined Statements of Income give effect to the acquisition of Enogex, notes payable repayments, reduction in the historical interest income received on the notes receivable—affiliated companies from CenterPoint Energy, which were paid off at formation, Term Loan Facility, Revolving Credit Facility, reduction of federal and state income taxes and reduction of the Partnership's interest in SESH as if the transactions and this offering, with respect to unit and per unit information, occurred on January 1, 2012. The Unaudited Pro Forma Condensed Combined Balance Sheet gives effect to consummation of the Partnership's initial public offering and the use of proceeds therefrom as if the transaction occurred on September 30, 2013.

The accompanying unaudited pro forma condensed combined financial statements are based on the assumptions and adjustments described in the accompanying notes and do not purport to present the Partnership's or Enogex's actual results of operations as if the transactions described above had occurred as of the dates indicated. The unaudited pro forma condensed combined financial statements are presented for illustrative purposes and are not indicative of what the financial position might have been or what results of operations might have been achieved had the transactions described above closed as of the dates indicated or the financial position or results of operations that might be achieved for any future periods.

ENABLE MIDSTREAM PARTNERS, LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF INCOME
For the Year Ended December 31, 2012

	Enable Midstream Partners, LP Historical	Enogex Historical	Pro Forma Adjustments	Enable Midstream Partners, LP Pro Forma
		(In millions)		
Revenues	$ 952	$ 1,609	$ 3 A	$ 2,564
Cost of Goods Sold, excluding depreciation and amortization	129	1,120	(11)A	1,238
Operating Expenses:				
Operation and maintenance	267	179	—	446
Depreciation and amortization	106	109	58 A	273
Gain on insurance proceeds	—	(8)	—	(8)
Taxes other than income	34	23	—	57
Total Operating Expenses	407	303	58	768
Operating Income	416	186	(44)	558
Other Income (Expense):				
Interest expense	(85)	(32)	80 B	(45)
			4 B	
			(19)C	
			(3)D	
			10 A	
Equity in earnings of equity method affiliates	31	—	(13)F	18
Interest income—affiliated companies	21	—	(21)B	—
Step acquisition gain	136	—	—	136
Other, net	—	(4)	—	(4)
Total Other Income (Expense)	103	(36)	38	105
Income before Income Taxes	519	150	(6)	663
Income tax expense (benefit)	203	—	(200)E	3
Net Income	316	150	194	660
Less: Net income attributable to noncontrolling interest	—	2	—	2
Net Income attributable to Enable Midstream Partners, LP	$ 316	$ 148	$ 194	$ 658
Number of outstanding limited partner units				
Basic and diluted earnings per limited partner unit				

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF INCOME
For the Nine Months Ended September 30, 2013

	Enable Midstream Partners, LP Historical	Enogex Historical	Pro Forma Adjustments	Enable Midstream Partners, LP Pro Forma
		(In millions)		
Revenues	$ 1,665	$ 630	$ 1 A	$ 2,296
Cost of Goods Sold, excluding depreciation and amortization	827	489	(4) A	1,312
Operating Expenses:				
Operation and maintenance	302	64	—	366
Depreciation and amortization	148	37	20 A	205
Impairment	12	—	—	12
Taxes other than income	37	8	—	45
Total Operating Expenses	499	109	20	628
Operating Income	339	32	(15)	356
Other Income (Expense):				
Interest expense	(53)	(10)	31 B	(35)
			2 B	
			(7) C	
			(1) D	
			3 A	
Equity in earnings of equity method affiliates	12	—	(3) F	9
Interest income—affiliated companies	9	—	(9) B	—
Other, net	—	9	—	9
Total Other Income (Expense)	(32)	(1)	16	(17)
Income before Income Taxes	307	31	1	339
Income tax expense (benefit)	(1,195)	—	1,196 E	1
Net Income	1,502	31	(1,195)	338
Less: Net income attributable to noncontrolling interest	2	—	—	2
Net Income attributable to Enable Midstream Partners, LP	$ 1,500	$ 31	$ (1,195)	$ 336
Number of outstanding limited partner units				
Basic and diluted earnings per limited partner unit				

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF INCOME
For the Nine Months Ended September 30, 2012

	Enable Midstream Partners, LP Historical	Enogex Historical	Pro Forma Adjustments	Enable Midstream Partners, LP Pro Forma
		(In millions)		
Revenues	$ 686	$ 1,178	$ 2 A	$ 1,866
Cost of Goods Sold, excluding depreciation and amortization	75	816	(9)A	882
Operating Expenses:				
Operation and maintenance	191	132	—	323
Depreciation and amortization	78	79	41 A	198
Gain on insurance proceeds	—	(8)	—	(8)
Taxes other than income	28	18	—	46
Total Operating Expenses	297	221	41	559
Operating Income	314	141	(30)	425
Other Income (Expense):				
Interest expense	(65)	(24)	62 B	(33)
			3 B	
			(15)C	
			(2)D	
			8 A	
Equity in earnings of equity method affiliates	25	—	(10)F	15
Interest income—affiliated companies	15	—	(15)B	—
Step acquisition gain	136	—	—	136
Other, net	1	(1)	—	—
Total Other Income (Expense)	112	(25)	31	118
Income before Income Taxes	426	116	1	543
Income tax expense (benefit)	160	—	(158)E	2
Net Income	266	116	159	541
Less: Net income attributable to noncontrolling interest	—	2	—	2
Net Income attributable to Enable Midstream Partners, LP	$ 266	$ 114	$ 159	$ 539
Number of outstanding limited partner units				
Basic and diluted earnings per limited partner unit				

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

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ENABLE MIDSTREAM PARTNERS. LP

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET
September 30, 2013

	Enable Midstream Partners, LP Historical	Pro Forma Adjustments	Enable Midstream Partners, LP Pro Forma
		(In millions)	
Cash and cash equivalents	$ 24	$ [G]	$
Accounts receivable, net	265	—	265
Accounts receivable—affiliated companies	24	—	24
Notes receivable—affiliated companies	4	—	4
Inventory	89	—	89
Gas Imbalances	10	—	10
Other current assets	9	—	9
Total current assets	425	—	
Property, plant and equipment, net	8,831	—	8,831
Intangible assets, net	392	—	392
Goodwill, net	1,061	—	1,061
Investment in equity method affiliates	200	—	200
Regulatory Assets, net	3	—	3
Other	38	—	38
Total other assets	1,694	—	
Total Assets	$ 10,950	$ —	$
Accounts payable	$ 289	$ —	$ 289
Accounts payable—affiliated companies	34	—	34
Current portion of long-term debt	205	—	205
Taxes accrued	47	—	47
Gas Imbalances	8	—	8
Other current liabilities	39	—	39
Total current liabilities	622	—	622
Notes payable—affiliated companies	363	—	363
Regulatory liabilities	21	—	21
Other liabilities	31	—	31
Total other liabilities	415	—	415
Long-term debt	1,727	[G]	
Enable Midstream Partners, LP Partners' Capital	8,152	[G]	
Noncontrolling interest	34	—	34
Total Partners' Capital	8,186	—	
Total Liabilities and Partners' Capital	$ 10,950	$ —	$

See Notes to Unaudited Pro Forma Condensed Combined Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

(1) Basis of Presentation

The accompanying unaudited pro forma condensed combined financial statements are based on the historical combined and consolidated financial statements of the Partnership. The Unaudited Pro Forma Condensed Combined Statements of Income give effect to the acquisition of Enogex, notes payable repayments, reduction in the historical interest income received on the notes receivable—affiliated companies from CenterPoint Energy, which were paid off at formation, entry into the Term Loan Facility and Revolving Credit Facility, reduction of federal and state income taxes and reduction of the Partnership's interest in SESH as if the transactions and this offering, with respect to unit and per unit information, occurred on January 1, 2012. The Unaudited Pro Forma Condensed Combined Balance Sheet gives effect to the consummation of the Partnership's initial public offering and the use of proceeds therefrom as if the transaction occurred on September 30, 2013. The unaudited pro forma condensed combined financial statements include the historical financial information of the Partnership and Enogex. All significant intercompany balances and transactions have been eliminated in combination. Because of certain related-party relationships and transactions, these unaudited pro forma condensed combined financial statements may not necessarily be indicative of the conditions that could have existed or results of operations that could have occurred if the Partnership had entered into similar arrangements with non-affiliated entities.

The accompanying unaudited pro forma condensed combined financial statements include statements of income for the year ended December 31, 2012 and for the nine months ended September 30, 2013 and 2012 and a balance sheet as of September 30, 2013. The Unaudited Pro Forma Condensed Combined Statement of Income for the year ended December 31, 2012 was derived from the respective historical audited combined statement of income of the Partnership and the historical audited consolidated statement of income for Enogex for the year ended December 31, 2012. The Unaudited Pro Forma Condensed Combined Statements of Income for the nine months ended September 30, 2013 and 2012 were derived from the respective historical unaudited combined and consolidated statements of income of the Partnership and the historical unaudited consolidated statements of income for Enogex for the four months ended April 30, 2013 and nine months ended September 30, 2012, respectively. The Unaudited Pro Forma Condensed Combined Balance Sheet as at September 30, 2013 was derived from the historical unaudited consolidated balance sheet of the Partnership as of September 30, 2013.

Certain amounts in the Partnership's and Enogex's historical combined and consolidated, respectively, statements of income have been reclassified to conform presentation.

(2) Pro Forma Adjustments

(A) This adjustment reflects the acquisition of Enogex on May 1, 2013. As a result of applying purchase accounting to the acquisition, the Partnership recognized adjustments to the historical net book value of Enogex's assets and liabilities that are expected to have a continuing effect on results as follows:

Revenue. As a result of the purchase price allocation, certain customer-based intangible assets historically amortized against revenue were written off and historically deferred revenues were not assigned value unless subject to future performance obligations. The impact of removing the historical amortization and the historical recognition of deferred revenues at May 1, 2013 results in a net increase to revenue of $3 million, $1 million and $2 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

Cost of Goods Sold, Excluding Depreciation and Amortization. As a result of applying purchase accounting to the acquisition of Enogex, liabilities were established for long-term loss contracts. The impact of recognizing these liabilities at May 1, 2013 results in a reduction to cost of goods sold, excluding depreciation and amortization, of $11 million, $4 million and $9 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

Depreciation and Amortization. As a result of applying purchase accounting to the acquisition of Enogex, property, plant and equipment, and identifiable intangible assets were recorded at their fair value, resulting in additional depreciation and amortization expense. The impact of the step-up on depreciation expense is $58 million, $20 million and $41 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

Interest Expense. As a result of applying purchase accounting to the acquisition of Enogex, Enogex's fixed rate senior notes were remeasured at fair value, resulting in the recognition of a premium of $46 million. Historically recognized deferred charges and discounts or premiums were assigned no fair value. The pro forma impact of the amortization of the premium, less the historical recognition of the premium, discount and deferred charges on interest expense, net of historical capitalized interest, is $10 million, $3 million and $8 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

(B) This adjustment reflects the settlement on May 1, 2013 of certain notes receivable—affiliated companies and notes payable—affiliated companies with CenterPoint Energy and OGE Energy, historically held by the Partnership and Enogex, respectively:

1) Reduction to notes receivable—affiliated companies from CenterPoint Energy of $479 million bearing variable interest of approximately 4.8%. The reduction results in the elimination of the historical affiliated interest income of $21 million, $9 million and $15 million for the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

2) Reduction to short-term notes payable—affiliated companies to CenterPoint Energy of $753 million bearing variable interest of approximately 4.8% and long-term notes payable—affiliated companies to CenterPoint of $646 million bearing fixed interest of 6.3%. This reduction results in the elimination of the historical affiliated interest expense of $80 million, $31 million and $62 million incurred during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

3) Reduction to short-term notes payable—affiliated companies to OGE Energy bearing variable interest of approximately 2.1%. This reduction results in the elimination of the historical affiliated interest expense of $4 million, $2 million and $3 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

(C) This adjustment reflects the entrance into the $1.05 billion Term Loan Facility on May 1, 2013 bearing variable interest of approximately 1.807%: this issuance results in an increase in interest expense of $19 million, $7 million and $15 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively, including amortization of deferred financing costs incurred on the Term Loan Facility and net of annual historical amounts capitalized for the allowance for funds used during construction of $2 million, $1 million and $1 million, respectively.

The incremental interest expense on the Term Loan Facility is calculated using the 1 month London Interbank Offered Rate (LIBOR) at September 30, 2013 plus 1.625%. A change in the borrowing rate of 1/8 percent would have an impact of approximately $1 million on the pro forma annual interest expense on the Term Loan Facility for all periods presented.

(D) This adjustment reflects the entrance into the Revolving Credit Facility on May 1, 2013 bearing variable interest of approximately 1.807% replacing the short-term note payable—affiliated companies to OGE

Energy: this issuance results in an increase in interest expense of $3 million, $1 million and $2 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively, including amortization of deferred financing costs incurred on the Revolving Credit Facility.

The incremental interest expense on the Revolving Credit Facility is calculated using the 1 month LIBOR at September 30, 2013 plus 1.625%. A change in the borrowing rate of 1/8 percent would have an impact of less than $1 million on the pro forma interest expense on the Revolving Credit Facility for all periods presented.

(E) This adjustment eliminates the income tax expense (benefit) of $200 million, ($1.2) billion and $158 million reported in the historical results of the Partnership during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively, that does not continue upon formation of the Partnership, which is a pass through entity for income tax purposes. Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. As a result of the conversion to a limited partnership, all outstanding current income assets and tax liabilities and the deferred income tax assets and liabilities were eliminated by recording an income tax benefit of $1.24 billion. The pro forma adjustment to income taxes for the nine months ended September 30, 2013 above removes the historical benefit of $1.24 billion recognized for the Partnership's conversion to a limited partnership since this is a one-time benefit that does not impact future continuing operations.

Enogex's historical earnings were taxable at the individual partner level, and as such, its historical results did not have any balances or activity associated with income taxes (other than Texas state margin taxes).

(F) This adjustment reflects the distribution of a 25.05% interest in Southeast Supply Header, LLC (SESH) to CenterPoint Energy in connection with the acquisition of Enogex on May 1, 2013. Prior to May 1, 2013, the Partnership held a 50.0% interest in SESH and, through this interest, historically recognized $26 million, $7 million and $20 million Equity in earnings of equity method affiliates for SESH during the year ending December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

The 25.05% interest in SESH distributed to CenterPoint Energy results in a pro forma reduction to earnings of equity method affiliates of $13 million, $3 million and $10 million during the year ended December 31, 2012 and the nine months ended September 30, 2013 and 2012, respectively.

(G) This adjustment reflects the assumed gross proceeds to the Partnership for the sale of common units at an initial public price of $ per common unit, offset by the payment of underwriting discounts of an aggregate $ million, together with estimated offering expenses of $ million, for a total of $ million.

(3) Pro Forma Net Income Per Common Unit

Pro forma basic and diluted net income per common unit is calculated by dividing the limited partners' interest in net income by the common units expected to be outstanding at the closing of this offering. Pro forma net income is calculated assuming that the pro forma cash distributions are equal to the pro forma net income attributable to the Partnership. Pro forma net income attributable to the Partnership prior to the acquisition of Enogex is not allocated to the limited partners for purposes of calculating pro forma net income per common unit.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
CenterPoint Energy, Inc. and Subsidiaries
Houston, Texas

We have audited the accompanying combined balance sheets of Enable Midstream Partners, LP (previously named CenterPoint Energy Field Services, LLC) and related companies as of December 31, 2012 and 2011, and the related statements of combined income, comprehensive income, cash flows, and parent net equity for each of the three years in the period ended December 31, 2012. These combined financial statements include the accounts of Enable Midstream Partners, LP, Enable Gas Transmission Company, LLC (previously named CenterPoint Energy Gas Transmission Company, LLC), Enable – Mississippi Gas Transmission Company, LLC (previously named CenterPoint Energy – Mississippi River Transmission, LLC), CenterPoint Energy Southeastern Pipelines Holding, LLC and other CenterPoint Energy midstream subsidiaries (collectively the “CenterPoint Midstream Entities” or the “Company”). The CenterPoint Energy Midstream Entities are under common control and common management. 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 combined financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the combined financial statements, the combined financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries and may not necessarily be indicative of the financial position, results of operations and cash flows that would have existed had the Company operated as a separate and unaffiliated company for each of the three years in the period ended December 31, 2012.

/s/ Deloitte & Touche LLP

Houston, Texas
April 30, 2013 (November 25, 2013 as to Note 14)

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ENABLE MIDSTREAM PARTNERS, LP

COMBINED STATEMENTS OF INCOME

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Revenues (including revenues from affiliates (Note 8))	$ 952	$ 932	$ 871
Cost of Goods Sold, excluding depreciation	129	101	98
Operating Expenses:			
Operation and maintenance (including expenses from affiliates (Note 8))	267	263	233
Depreciation	106	91	77
Taxes other than income taxes	34	37	37
Total Operating Expenses	407	391	347
Operating Income	416	440	426
Other Income (Expense):			
Interest expense—affiliated companies	(85)	(90)	(83)
Equity in earnings of equity method affiliates	31	31	29
Interest income—affiliated companies	21	14	9
Step acquisition gain	136	—	—
Other, net	—	—	(2)
Total	103	(45)	(47)
Income Before Income Taxes	519	395	379
Income tax expense	203	163	155
Net Income attributable to Enable Midstream Partners, LP	$ 316	$ 232	$ 224

See Notes to Combined Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Net income	$ 316	$ 232	$ 224
Other comprehensive income, net of tax:			
Adjustment to pension and other postretirement plans (net of tax of $0, $0, and $0)	—	—	—
Other comprehensive income	—	—	—
Comprehensive income attributable to Enable Midstream Partners, LP	$ 316	$ 232	$ 224

See Notes to Combined Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(In millions)	
ASSETS		
Current Assets:		
Accounts receivable	$ 78	$ 63
Accounts receivable—affiliated companies	25	26
Notes receivable—affiliated companies	479	402
Inventory	57	59
Taxes receivable	45	44
Deferred income tax assets	31	32
Other current assets	24	20
Total current assets	739	646
Property, Plant and Equipment		
Property, plant and equipment	5,175	4,442
Less accumulated depreciation and amortization	470	372
Property, plant and equipment, net	4,705	4,070
Other Assets:		
Goodwill	629	605
Investment in equity method affiliates	405	472
Other	4	3
Total other assets	1,038	1,080
Total Assets	$ 6,482	$ 5,796
LIABILITIES AND PARENT NET EQUITY		
Current Liabilities:		
Accounts payable	$ 83	$ 74
Accounts payable—affiliated companies	28	31
Notes payable—affiliated companies	753	922
Taxes accrued	25	44
Gas Imbalances	7	7
Other	26	31
Total current liabilities	922	1,109
Other Liabilities:		
Accumulated deferred income taxes, net	1,272	1,082
Notes payable—affiliated companies	1,009	646
Benefit obligations	21	21
Regulatory liabilities	16	16
Other	21	18
Total other liabilities	2,339	1,783
Commitments and Contingencies (Note 10)		
Parent Net Equity		
Parent net investment	3,221	2,904
Accumulated other comprehensive loss	(6)	(6)
Parent Net Equity, before Noncontrolling interest	3,215	2,898
Noncontrolling interest	6	6
Total Parent Net Equity	3,221	2,904
Total Liabilities And Parent Net Equity	$ 6,482	$ 5,796

See Notes to Combined Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP

STATEMENTS OF COMBINED CASH FLOWS

	Year Ended December 31, 2012	2011	2010
	(In millions)		
Cash Flows from Operating Activities:			
Net income	$ 316	$ 232	$ 224
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	106	91	77
Deferred income taxes	196	176	184
Equity in earnings of equity method affiliates, net of distributions	8	8	13
Step acquisition gain	(136)	—	—
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(9)	45	(54)
Accounts receivable, affiliates	1	28	(33)
Accounts payable, affiliates	(3)	(1)	17
Inventory	2	13	(20)
Taxes receivable	(1)	13	(38)
Accounts payable	(3)	7	(5)
Fuel cost recovery	—	4	(6)
Taxes accrued	(19)	21	6
Other current assets	(3)	10	(29)
Other current liabilities	(4)	(3)	1
Other assets	—	3	(1)
Other liabilities	—	19	(6)
Other, net	—	(4)	(22)
Net cash provided by operating activities	451	662	308
Cash Flows from Investing Activities:			
Capital expenditures, net of acquisitions	(202)	(346)	(723)
Acquisitions, net of cash	(360)	—	—
Increase in notes receivable from affiliates	(77)	(219)	(95)
Investment in equity method affiliates	(5)	(13)	(20)
Other, net	(1)	18	38
Net cash used in investing activities	(645)	(560)	(800)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term notes payable with affiliates, net	(169)	(102)	492
Proceeds from long-term notes payable with affiliates	363	—	—
Net cash provided by (used in) financing activities	194	(102)	492
Net Decrease in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of the Year	—	—	—
Cash and Cash Equivalents at End of the Year	$ —	$ —	$ —
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 85	$ 90	$ 83
Income taxes (refunds), net	26	(67)	26
Non-cash transactions:			
Accounts payable related to capital expenditures	$ 37	$ 31	$ 78

See Notes to Combined Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

STATEMENTS OF COMBINED PARENT NET EQUITY

	2012	2011	2010
		(In millions)	
Parent Net Investment			
Balance, beginning of year	$2,904	$2,672	$2,448
Net income	316	232	224
Net transfers from parent	1	—	—
Balance, end of year	3,221	2,904	2,672
Accumulated Other Comprehensive Loss			
Balance, beginning of year	(6)	(6)	(6)
Adjustment to pension and postretirement plans	—	—	—
Balance, end of year	(6)	(6)	(6)
Noncontrolling Interest			
Balance, beginning of year	6	6	6
Net income attributable to noncontrolling interests	—	—	—
Balance, end of year	6	6	6
Total Parent Net Equity	$3,221	$2,904	$2,672

See Notes to Combined Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

NOTES TO COMBINED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

Background

On March 14, 2013, CenterPoint Energy, Inc. (and together with its subsidiaries, CenterPoint Energy) entered into a Master Formation Agreement (MFA) with OGE Energy Corp. (OGE Energy) and affiliates of ArcLight Capital Partners, LLC (ArcLight), pursuant to which CenterPoint Energy, OGE Energy and ArcLight agreed to form Enable Midstream Partners, LP (Partnership) that will initially operate as a private limited partnership. The transaction is expected to close in the second quarter of 2013. Pursuant to the MFA, (i) CenterPoint Energy will convert its indirect wholly owned subsidiary, CenterPoint Energy Field Services, LLC, a Delaware limited liability company (CEFS), into a Delaware limited partnership that will become the Partnership, (ii) CenterPoint Energy will contribute to CEFS its equity interests in each of Enable Gas Transmission Company, LLC (EGT, previously named CenterPoint Energy Gas Transmission Company, LLC), Enable—Mississippi River Transmission, LLC (MRT, previously named CenterPoint Energy—Mississippi River Transmission, LLC), and certain of its other midstream subsidiaries (Other CNP Midstream Subsidiaries), (iii) CEFS will retain a 24.95% interest in Southeast Supply Header, LLC (SESH and, collectively with CEFS, EGT, MRT and the Other CNP Midstream Subsidiaries and each of their respective subsidiaries, the Partnership) and (iv) OGE Energy and ArcLight will contribute 100% of the equity interests in Enable Oklahoma Intrastate Transmission, LLC (Enogex, previously named Enogex LLC), to the Partnership. The Partnership will be equally controlled by CenterPoint Energy and OGE Energy through the Partnership's general partner Enable GP, LLC.

These combined financial statements of the Partnership consist of the entities comprising CenterPoint Energy's Pipelines and Field Services reportable business segments that CenterPoint Energy contributed to the Partnership. CenterPoint Energy owns other assets and entities that are not historically included in CenterPoint Energy's Pipelines and Field Services reportable segments and are not subject to the MFA and, therefore, are not included in these combined financial statements. The Partnership refers to CenterPoint Energy's Interstate Pipelines segment as the Transportation and Storage segment and CenterPoint Energy's Field Services segment as the Gathering and Processing segment.

Through its operating units, the Partnership is engaged in the business of gathering, processing, transporting and storing natural gas. The principal business entities included in the historical combined financial statements of the Partnership are: CEFS, EGT, MRT, and CenterPoint Energy Southeastern Pipelines Holding, LLC (SEPH), which owns a 50% investment in SESH. The following is a brief description of the operations of each business comprising the Partnership:

- CEFS owns and operates 3,700 miles of gathering pipelines and processing plants that collect natural gas from approximately 140 separate systems located in major producing fields in Arkansas, Louisiana, Oklahoma and Texas. Enable East Texas Gas Processing, LLC, a wholly owned subsidiary of CEFS, owns and operates Waskom Gas Processing Company, which owns a natural gas processing plant engaged in the processing and marketing of natural gas and natural gas liquids, predominantly in Texas and northwest Louisiana. Prior to the acquisition of an additional 50% interest in Waskom Gas Processing Company in July 2012 (see Note 6), the Partnership owned a 50% equity interest in Waskom Gas Processing Company and accounted for its investment using the equity method of accounting.
- EGT owns and operates an interstate natural gas transmission pipeline and storage system located in the states of Arkansas, Kansas, Louisiana, Oklahoma, Mississippi, Missouri, Tennessee and Texas.
- MRT owns and operates an interstate natural gas transmission and storage pipeline system located in the states of Arkansas, Illinois, Louisiana, Missouri and Texas.

- SEPH owns a 50% investment in SESH, which owns and operates a natural gas transmission pipeline. The pipeline extends from the Perryville Hub in northeastern Louisiana to Alabama. SESH interconnects with 14 major north-south pipelines and three high deliverability storage facilities. The Partnership accounts for this investment using the equity method.

Basis for Presentation

These combined financial statements and related notes of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States on the basis of CenterPoint Energy's historical ownership percentages of the entities. These combined financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy and may not necessarily be indicative of the condition that would have existed or the results of operations if the Partnership had been operated as a separate and unaffiliated entity. All of the Partnership's combined entities were under common control and management for the periods presented, and all intercompany transactions and balances are eliminated in combination. The Partnership uses the equity method of accounting for investments in entities in which the Partnership has an ownership interest between 20% and 50% and exercises significant influence.

The Partnership receives services and support functions from CenterPoint Energy. The Partnership's operations are dependent on CenterPoint Energy's ability to perform these services and support functions which include accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs, and human resources, as well as information technology services and other shared services such as corporate security, facilities management, office support services, and purchasing and logistics. The cost of these services has been charged directly to the Partnership using methods that management believes are reasonable. These methods include negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. These charges are not necessarily indicative of what would have been incurred had the Partnership not been an affiliate. For additional disclosures of transactions between the Partnership and related parties, see Note 8.

CenterPoint Energy has provided the necessary capital to finance the Partnership's operations. Net parent investment on the combined balance sheet represents the amount of capital investments made by CenterPoint Energy in the Partnership and the Partnership's accumulated net earnings after taxes.

The combined financial statements and the related financial statement disclosures reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods.

For a description of the Partnership's reportable business segments, see Note 12.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(b) Revenues

Revenues for gathering, processing, transportation and storage services for the partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts Receivable on the Combined Balance Sheets and in Revenues on the Combined Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

The Partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership has no material deferred revenues on the Combined Balance Sheets as of December 31, 2012 or 2011.

(c) Long-Lived Assets

The Partnership records property, plant and equipment at historical cost. The Partnership expenses repair and maintenance costs as incurred.

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets.

(d) Goodwill

The Partnership performs its goodwill impairment tests at least annually and evaluates goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. The impairment evaluation for goodwill is performed by using a two-step process. In the first step, the fair value of each reporting unit is compared with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is generally determined on the basis of discounted cash flows. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference.

(e) Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the Transportation and Storage business segment. The Partnership's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of December 31, 2012 and 2011, these removal costs of $16 million and $16 million, respectively, are classified as regulatory liabilities in the Combined Balance Sheets.

(f) Depreciation Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period.

(g) Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for combined entities that apply guidance for accounting for regulated operations. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During 2012, 2011 and 2010, the Partnership capitalized interest and AFUDC of $2 million, $-0- and $7 million, respectively.

(h) Income Taxes

The Partnership is included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. The Partnership uses the asset and liability method of accounting for deferred income taxes in accordance with accounting guidance for income taxes. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance is established against deferred tax assets for which management believes realization is not considered more likely than not. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy. The Partnership recognizes interest and penalties as a component of income tax expense. For more information, see Note 9 to the combined financial statements.

(i) Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. It is the policy of management to review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and based on this review, has determined that no allowance for doubtful accounts was required for both December 31, 2012 and 2011.

(j) Inventory

Inventory consists principally of materials and supplies, which are valued at the lower of average cost or market. Materials and supplies are recorded to inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

(k) Derivative Instruments

The Partnership is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. At times, the Partnership utilizes derivative instruments such as physical forward contracts to mitigate the impact of changes in commodity prices on its operating results and cash flows. Such derivatives are recognized in the Partnership's Combined Balance Sheets at their fair value unless the Partnership elects the normal purchase and sales exemption for qualified physical transactions. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business. All outstanding derivative instruments are designated as normal purchase or normal sale during the periods presented.

The Partnership's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

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(l) Fair Value Measurements

The Partnership determines 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. As required, the Partnership utilizes valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy included in current accounting guidance. The Partnership generally applies the market approach to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

(m) Environmental Costs

The Partnership expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Partnership expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Partnership records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. There are no material amounts accrued at December 31, 2012 or 2011.

(n) Cash and Cash Equivalents

The Partnership considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. There were no cash equivalents at December 31, 2012 and 2011, respectively.

(o) New Accounting Pronouncements

Management believes that recently issued standards, which are not yet effective, will not have a material impact on the Partnership's combined financial position, results of operations or cash flows upon adoption.

(3) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2012	December 31, 2011
		(In millions)	
Transportation and Storage	56	$ 2,816	$ 2,687
Gathering and Processing	42	2,359	1,755
Total		5,175	4,442
Accumulated depreciation:			
Transportation and Storage		352	299
Gathering and Processing		118	73
Total accumulated depreciation		470	372
Property, plant and equipment, net		$ 4,705	$ 4,070

(4) Goodwill

The Partnership determined that its reporting units consist of its reportable segments. Goodwill by reportable business segment is as follows (in millions):

	Transportation and Storage	Gathering and Processing	Total
December 31, 2011	$ 579	$ 26	$605
Acquisition of Waskom	—	24	24
December 31, 2012	$ 579	$ 50	$629

The Partnership performed its annual impairment test in the third quarter of 2012, 2011 and 2010 and determined that no impairment charge for goodwill was required for the periods presented.

(5) Employee Benefit Plans

Pension Plans

Substantially all of the Partnership's employees participate in CenterPoint Energy's qualified non-contributory pension plan. Under the cash balance formula, participants accumulate a retirement benefit based upon 5% of eligible earnings.

CenterPoint Energy's funding policy is to review amounts annually in accordance with applicable regulations in order to achieve adequate funding of projected benefit obligations. Pension expense is allocated to the Partnership based on covered employees. This calculation is intended to allocate pension costs in the same manner as a separate employer plan. Assets of the plan are not segregated or restricted by CenterPoint Energy's participating subsidiaries. The Partnership recognized pension expense of $8 million for each of the years ended December 31, 2012, 2011 and 2010, respectively.

In addition to the plan, the Partnership participates in CenterPoint Energy's non-qualified benefit restoration plan, which allows participants to retain the benefits to which they would have been entitled under the qualified pension plan except for federally mandated limits on these benefits or on the level of salary on which these benefits may be calculated. The Partnership recognized pension expense of less than $1 million for each of the years ended December 31, 2012, 2011 and 2010, respectively.

Related to CenterPoint Energy's qualified and non-qualified pension plans described above, as of December 31, 2012 and 2011, CenterPoint Energy has a benefit obligation of $2.32 billion and $2.09 billion, respectively, fair value of plan assets of $1.7 billion and $1.5 billion, respectively, and net unfunded benefit liabilities of $618 million and $579 million, respectively. These plans are considered single employer plans, and as such, the assets are not allocated to the Partnership. The portion of CenterPoint Energy's benefit obligation related to employees who perform services for the Partnership was $214 million and $189 million as of December 31, 2012 and 2011, respectively.

Savings Plan

The Partnership participates in CenterPoint Energy's qualified savings plan, which includes a cash or deferred arrangement under Section 401(k) of the Internal Revenue Code of 1986, as amended. Under the plan, participating employees may contribute a portion of their compensation, on a pre-tax or after-tax basis, generally up to a maximum of 50% of compensation. The Partnership matches 100% of the first 6% of each employee's compensation contributed. The matching contributions are fully vested at all times. CenterPoint Energy allocates to the Partnership the savings plan benefit expense related to the Partnership's employees. Savings plan benefit expense was $5 million, $5 million and $4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Postretirement Benefits

The Partnership's employees participate in CenterPoint Energy's plans which provide certain healthcare and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees become eligible for these benefits if they have met certain age and service requirements at retirement, as defined in the plans. Under plan amendments effective in early 1999, healthcare benefits for future retirees were changed to limit employer contributions for medical coverage. Such benefit costs are accrued over the active service period of employees. The Partnership is required to fund a portion of its obligations in accordance with rate orders. All other obligations are funded on a pay-as-you-go basis.

The net postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Interest cost on accumulated benefit obligation	$ 1	$ 1	$ 1
Amortization of net loss	1	1	—
Net postretirement benefit cost	$ 2	$ 2	$ 1

The Partnership used the following assumptions to determine net postretirement benefit costs:

	Year Ended December 31,		
	2012	2011	2010
Discount rate	4.80%	5.20%	5.70%
Expected return on plan assets	4.00%	6.00%	6.00%

In determining net periodic benefits cost, the Partnership uses fair value, as of the beginning of the year, as its basis for determining expected return on plan assets.

Following are reconciliations of the Partnership's beginning and ending balances of its postretirement benefit plan's benefit obligation, plan assets and funded status for 2012 and 2011. The measurement dates for plan assets and obligations were December 31, 2012 and 2011.

	December 31, 2012	December 31, 2011
	(In millions, except actuarial assumptions)	
Change in Benefit Obligation		
Accumulated benefit obligation, beginning of year	$ 23	$ 22
Interest cost	1	1
Benefits paid	(2)	(2)
Actuarial loss	3	2
Accumulated benefit obligation, end of year	$ 25	$ 23
Change in Plan Assets		
Plan assets, beginning of year	$ 6	$ 6
Benefits paid	(2)	(2)
Employer contributions	3	2
Plan assets, end of year	$ 7	$ 6
Amounts Recognized in Balance Sheets		
Current liabilities-other	$ (1)	$ (1)
Other liabilities-benefit obligations	(17)	(16)
Net liability, end of year	$ (18)	$ (17)
Actuarial Assumptions		
Discount rate	3.90%	4.80%
Expected long-term return on assets	4.00%	4.00%
Healthcare cost trend rate assumed for the next year	9.00%	8.00%
Prescription cost trend rate assumed for the next year	9.00%	8.00%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5.50%	5.50%
Year that the healthcare rate reaches the ultimate trend rate	2017	2017
Year that the prescription drug rate reaches the ultimate trend rate	2017	2017

The discount rate assumption was determined by matching the accrued cash flows of CenterPoint Energy's plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to 99 years.

The expected rate of return assumption was developed by a weighted-average return analysis of the targeted asset allocation of CenterPoint Energy's plans and the expected real return for each asset class, based on the long-term capital market assumptions, adjusted for investment fees and diversification effects, in addition to expected inflation. For measurement purposes, healthcare and prescription costs are assumed to increase to 9.00% during 2013, after which this rate decreases until reaching the ultimate trend rate of 5.50% in 2017.

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Amounts recognized in accumulated other comprehensive loss consist of the following:

	December 31, 2012	December 31, 2011
	(In millions)	
Unrecognized actuarial loss	$ 14	$ 12
Unrecognized prior service cost	—	1
	14	13
Less deferred tax benefit(1)	(8)	(7)
Net amount recognized in accumulated other comprehensive loss	$ 6	$ 6

(1) The Partnership's postretirement benefit obligation is reduced by the impact of previously non-taxable government subsidies under the Medicare Prescription Drug Act. Because the subsidies were non-taxable, the temporary difference used in measuring the deferred tax impact was determined on the unrecognized losses excluding such subsidies.

The total expense recognized in net periodic costs and other comprehensive income for postretirement benefits were:

	Year Ended December 31, 2012	2011	2010
		(In millions)	
Net postretirement benefit cost	$ 2	$ 2	$ 1
Changes in other comprehensive income:			
Net actuarial loss	2	—	(1)
Total changes in other comprehensive income	2	—	(1)
Total net periodic costs and other comprehensive income	$ 4	$ 2	$ —

The amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost during 2013 are as follows:

	Postretirement Benefits
	(In millions)
Unrecognized actuarial loss	$ 1
Amounts in other comprehensive income to be recognized as net periodic cost in 2013	$ 1

Assumed healthcare cost trend rates have a significant effect on the reported amounts for the Partnership's postretirement benefit plans. A 1% change in the assumed healthcare cost trend rate would have the following effects:

	1% Increase	1% Decrease
	(In millions)	
Effect on the postretirement benefit obligation	$ 1	$ (1)
Effect on the total of service and interest cost	—	—

In managing the investments associated with the postretirement benefit plan, the Partnership's objective is to preserve and enhance the value of plan assets while maintaining an acceptable level of volatility. These objectives are expected to be achieved through an investment strategy, which manages liquidity requirements while maintaining a long-term horizon in making investment decisions, and efficient and effective management of plan assets.

As part of the investment strategy discussed above, the Partnership has adopted and maintains the following asset allocation ranges for its postretirement benefit plan:

Domestic equity	15-25%
Fixed income	75-85%
Cash	0-2%

The fair values of the Partnership's postretirement plan assets at December 31, 2012 and 2011, by asset category are as follows:

	Fair Value Measurements at December 31, 2012			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(In millions)			
Mutual funds[1]	$ 7	$ 7	$ —	$ —
Total	$ 7	$ 7	$ —	$ —

(1) 77% of the amount invested in mutual funds is in fixed income securities and 23% is in domestic equities.

	Fair Value Measurements at December 31, 2011			
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(In millions)			
Mutual funds[1]	$ 6	$ 6	$ —	$ —
Total	$ 6	$ 6	$ —	$ —

(1) 78% of the amount invested in mutual funds is in fixed income securities and 22% is in domestic equities.

The Partnership expects to contribute $2 million to its postretirement benefits plan in 2013.

The following benefit payments and Medicare subsidy receipts are expected from the postretirement benefit plan:

	Postretirement Benefit Plan	
	Benefit Payments	Medicare Subsidy Receipts
	(In millions)	
2013	$ 2	$ —
2014	2	—
2015	2	—
2016	2	—
2017	2	—
2018-2022	12	(3)

Postemployment Benefits

The Partnership participates in CenterPoint Energy's plan which provides postemployment benefits for former or inactive employees, their beneficiaries and covered dependents, after employment but before retirement (primarily healthcare and life insurance benefits for participants in the long-term disability plan). The Partnership recorded postemployment expense of less than $1 million, expense of less than $1 million and income of less than $1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Included in "Benefit Obligations" in the accompanying Combined Balance Sheets at December 31, 2012 and 2011, was $1 million and $2 million, respectively, related to postemployment benefits.

Other Non-Qualified Plans

The Partnership participates in CenterPoint Energy's deferred compensation plans that provide benefits payable to directors, officers and certain key employees or their designated beneficiaries at specified future dates, upon termination, retirement or death. Benefit payments are made from the general assets of the Partnership. During 2012, 2011 and 2010, the benefits expenses relating to these programs were less than $1 million in each year. Included in "Benefit Obligations" in the accompanying Combined Balance Sheets at December 31, 2012 and 2011, was $1 million and $2 million, respectively, relating to deferred compensation plans.

(6) Investments in Equity Method Affiliates

The Partnership's investments in equity method affiliates include a 50% ownership interest in Southeast Supply Header, LLC (SESH) which owns and operates a 270-mile interstate natural gas pipeline.

Prior to July 2012, the Partnership owned a 50% interest in Waskom Gas Processing Company (Waskom), a Texas general partnership, which owns and operates a natural gas processing plant and accounted for its investment in Waskom using the equity method of accounting. During 2010, the Partnership made an additional investment of $20 million in Waskom.

On July 31, 2012, the Partnership purchased the 50% interest that it did not already own in Waskom, as well as other gathering and related assets from a third-party for approximately $273 million in cash. The amount of the purchase price allocated to the acquisition of the 50% interest in Waskom was approximately $201 million, with the remaining purchase price allocated to the other gathering assets. The $273 million purchase price was allocated to the fair value of assets received as follows: $253 million to property, plant and equipment; $16 million to goodwill; and the remaining balance to other assets and liabilities. The original 50% interest held by the Partnership in Waskom had a fair value of approximately $201 million prior to its acquisition of the additional 50% interest in Waskom, based on a discounted cash flow methodology (a level 3 valuation technique for which the key inputs are the discount rate and operating cash flow projections). The purchase of the additional 50% interest in Waskom was determined to be a business combination achieved in stages, and as such the Partnership recorded a pre-tax gain of approximately $136 million and goodwill of $8 million on July 31, 2012, which is the result of the Partnership remeasuring its original 50% interest in Waskom to fair value. As a result of the purchase, the Partnership consolidated its wholly owned investment in Waskom beginning on July 31, 2012, which included goodwill totaling $24 million, consisting of $17 million related to Waskom (including the re-measurement of its existing 50% interest) and $7 million related to the other gathering and related assets.

Investment in Equity Method Affiliates:

	December 31, 2012	December 31, 2011
	(In millions)	
Waskom	$ —	$ 63
SESH	404	409
Other	1	—
Total	$ 405	$ 472

Equity in Earnings of Equity Method Affiliates:

	Year Ended December 31, 2012(1)	2011	2010
	(In millions)		
Waskom	$ 5	$ 10	$ 10
SESH	26	21	19
Total	$ 31	$ 31	$ 29

(1) On July 31, 2012, Waskom became a wholly owned subsidiary of the Partnership. Beginning on August 1, 2012, Waskom's operating results are combined in the Statement of Combined Income.

Summarized financial information of Waskom is presented below:

	December 31, 2011 (In millions)
Balance Sheets:	
Current assets	$ 16
Property, plant and equipment, net	124
Other non-current assets	—
Total assets	$ 140
Current liabilities	$ 15
Non-current liabilities	1
Partner's equity	124
Total liabilities and member's equity	$ 140
Reconciliation:	
Investment in Waskom	$ 63
Less: Purchase price adjustment	(1)
The Partnership's share of member's equity	$ 62

	Year Ended December 31,		
	2012[(1)]	2011	2010
	(In millions)		
Income Statements:			
Revenues	$ 77	$ 129	$ 121
Operating income	11	20	20
Net income	11	19	20
Reconciliation:			
Equity in earnings of Waskom	$ 5	$ 10	$ 10
The Partnership's share of member's equity	$ 5	$ 10	$ 10

(1) Reflects Waskom's income statement through July 31, 2012, the date Waskom became a wholly owned subsidiary of the Partnership. Beginning on August 1, 2012, Waskom's operating results are combined in the Statement of Combined Income.

Summarized financial information of SESH is presented below:

	December 31,	
	2012	2011
	(In millions)	
Balance Sheets:		
Current assets	$ 51	$ 39
Property, plant and equipment, net	1,147	1,161
Other non-current assets	1	2
Total assets	$1,199	$1,202
Current liabilities	$ 19	$ 13
Non-current liabilities	377	375
Member's equity	803	814
Total liabilities and member's equity	$1,199	$1,202
Reconciliation:		
Investment in SESH	$ 404	$ 409
Less: Capitalized interest on investment in SESH	(2)	(2)
The Partnership's share of member's equity	$ 402	$ 407

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Income Statements:			
Revenues	$110	$100	$96
Operating income	71	61	58
Net income	52	42	39
Reconciliation:			
Equity in earnings of SESH	$ 26	$ 21	$19
The Partnership's share of member's equity	$ 26	$ 21	$19

(7) Short-term and Long-term Notes Payable to Affiliates

The Partnership has outstanding short-term and long-term notes payable to affiliates of CenterPoint Energy as presented below:

	December 31, 2012		December 31, 2011	
	Long-Term	Current	Long-Term	Current
	(In millions)			
Short-term notes payable—affiliated companies:				
Notes payable—affiliated companies[1]	$ —	$ 753	$ —	$ 922
Long-term notes payable—affiliated companies:				
Notes payable—affiliated companies[2]	$ 363	$ —	$ —	$ —
Notes payable—affiliated companies[3]	646	—	646	—
Total long-term notes payable—affiliated companies	$ 1,009	$ —	$ 646	$ —

(1) These notes are payable on demand to CenterPoint Energy and may be prepaid in full at any time without premium or penalty. Substantially all of these notes represent the Partnership's money pool borrowings. At December 31, 2012 and December 31, 2011, the Partnership's money pool borrowings had interest rates of 4.869% and 4.666%, respectively. See Note 8 for further discussion.

(2) These notes are payable to CenterPoint Energy and mature in 2017. Notes having an aggregate principal amount of approximately $273 million bear a fixed interest rate of 2.10% and notes having an aggregate principal amount of approximately $90 million bear a fixed interest rate of 2.45%.

(3) These notes are payable to CenterPoint Energy, bear a fixed interest rate of 6.30% and mature in 2036.

(8) Related Party Transactions

The related party transactions with CenterPoint Energy and its affiliates are described below. See Note 7 for a description of the short-term and long-term notes payable to affiliates and the related affiliated interest expense.

Affiliated revenues and affiliated natural gas sales are comprised of gas transportation and processing revenues and sales of natural gas to CenterPoint Energy, respectively.

	Year Ended December 31,		
	2012	2011	2010
	(In millions)		
Gas transportation and storage—CenterPoint Energy	$ 133	$ 140	$ 113

As discussed in Note 1, CenterPoint Energy provides corporate services such as management, administration, accounting, legal and other services to the Partnership. Amounts charged to the Partnership by CenterPoint Energy for corporate services were $39 million, $37 million and $33 million for 2012, 2011 and 2010, respectively, and are included primarily in operation and maintenance in the Combined Income Statements. The cost of these services has been charged directly to the Partnership using methods that management believes are reasonable. Refer to Note 1 for a description of the allocation methods.

The Partnership participates in a "money pool" through which it can borrow or invest with CenterPoint Energy on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The Partnership's money pool borrowings and investments are reflected in notes payable—affiliated companies and notes receivable—affiliated companies, respectively, in the Combined Balance Sheets. The notes receivable—affiliated companies include $434 million and $362 million investments in the money pool as of December 31, 2012 and December 31, 2011, respectively. As of December 31, 2012 and December 31, 2011, money pool investments had an interest rate of 4.869% and 4.666%, respectively.

Notes receivable—affiliated companies also includes other notes receivable of $45 million and $40 million as of December 31, 2012 and December 31, 2011. Such notes had an interest rate of 3.25% at December 31, 2012 and December 31, 2011.

(9) Income Taxes

The components of the Partnership's income tax expense were as follows:

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Current income tax expense (benefit):			
Federal	$ 6	$ (20)	$ (37)
State	1	7	8
Total current expense (benefit)	7	(13)	(29)
Deferred income tax expense (benefit):			
Federal	164	146	164
State	32	30	20
Total deferred expense	196	176	184
Total income tax expense	$ 203	$ 163	$ 155

A reconciliation of the expected federal income tax expense using the federal statutory income tax rate to the actual income tax expense and resulting effective income tax rate is as follows:

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Income before income taxes	$ 519	$ 395	$ 379
Federal statutory rate	35%	35%	35%
Expected federal income tax expense	182	138	133
Increase in tax expense resulting from:			
State income taxes, net of federal income tax	21	24	18
Tax law change in deductibility of retiree health care costs	—	—	4
Other, net	—	1	—
Total	21	25	22
Total income tax expense	$ 203	$ 163	$ 155
Effective tax rate	39.1%	41.2%	40.9%

The tax effects of temporary differences that give rise to significant portions of deferred tax assets and liabilities were as follows:

	December 31, 2012	December 31, 2011
	(In millions)	
Deferred tax assets:		
Current:		
Deferred gas costs	$ 29	$ 30
Other	2	2
Total current deferred tax assets	31	32
Non-current:		
Employee benefits	11	10
Net operating loss carryforwards	8	59
Other	7	9
Total non-current deferred tax assets	26	78
Total deferred tax assets	57	110
Deferred tax liabilities:		
Non-current:		
Depreciation	1,219	1,084
Other	79	76
Total non-current deferred tax liabilities	1,298	1,160
Accumulated deferred income taxes, net	$1,241	$1,050

The Partnership is included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculates its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy.

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2012, the Partnership has approximately $5 million of federal net operating loss carryforwards which begin to expire in 2031 and $120 million of state net operating loss carryforwards which expire in various years between 2013 and 2032. The Partnership expects to realize the benefit of its deferred tax assets before they expire so there is no valuation allowance at December 31, 2012.

Uncertain Income Tax Positions. The following table reconciles the beginning and ending balance of the Partnership's unrecognized tax benefits:

	December 31, 2012	December 31, 2011	December 31, 2010
	(In millions)		
Balance, beginning of year	$ 3	$ 5	$ 5
Tax Positions related to prior years:			
Reductions	(3)	(2)	—
Balance, end of year	$—	$ 3	$ 5

The Partnership's unrecognized tax benefits on uncertain tax positions would not affect the effective income tax rate if they were recognized. The Partnership recognizes interest and penalties as a component of income tax expense. There was no unrecognized tax benefit as of December 31, 2012. The Partnership recognized approximately $1 million of income tax benefit in 2012 and less than $1 million of income tax expense related to the Partnership's interest on uncertain income tax positions during 2011 and 2010, respectively. The Partnership accrued zero interest on uncertain income tax positions related to the Partnership at December 31, 2012 and approximately $1 million at December 31, 2011.

Tax Audits and Settlements. CenterPoint Energy's consolidated federal income tax returns have been audited by the IRS and settled through the 2009 tax year. CenterPoint Energy has filed claims for income tax refunds that are pending review by the IRS for tax years 2002, 2003 and 2004. CenterPoint Energy is currently under examination by the IRS for tax years 2010 and 2011. The Partnership has considered the effects of these examinations in its accrual for settled issues and liability for uncertain income tax positions as of December 31, 2012.

(10) Commitments and Contingencies

(a) Lease Commitments

The following table sets forth information concerning the Partnership's obligations under non-cancelable long-term operating leases at December 31, 2012, which primarily consist of rental agreements for building space, data processing equipment, compression equipment and rights of way (in millions):

2013	$ 3
2014	2
2015	2
2016	1
2017	1
2018 and beyond	4
Total	$13

Total rental expense for all operating leases was $12 million, $16 million and $26 million in 2012, 2011 and 2010, respectively.

(b) Long-Term Gas Gathering and Treating Agreements.

The Partnership has entered into long-term agreements with an affiliate of Encana Corporation (Encana) and an affiliate of Royal Dutch Shell plc (Shell) to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana.

Under the long-term agreements, Encana or Shell may elect to require the Partnership to expand the capacity of its gathering systems by up to an additional 1.3 Bcf per day. The Partnership estimates that the cost to expand the capacity of its gathering systems by an additional 1.3 Bcf per day would be as much as $440 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand system capacity.

(c) Legal, Environmental and Other Matters

Legal Matters

Natural Gas Measurement Lawsuits. Certain of the Partnership's combined entities are defendants in two mismeasurement lawsuits brought against approximately 245 pipeline companies and their affiliates pending in state court in Stevens County, Kansas. In one case (originally filed in May 1999 and amended four times), the plaintiffs purport to represent a class of royalty owners who allege that the defendants have engaged in systematic mismeasurement of the volume of natural gas for more than 25 years. The plaintiffs amended their petition in this suit in July 2003 in response to an order from the judge denying certification of the plaintiffs' alleged class. In the amendment, the plaintiffs dismissed their claims against certain defendants (including two combined entities of the Partnership), limited the scope of the class of plaintiffs they purport to represent and eliminated previously asserted claims based on mismeasurement of the Btu content of the gas. The same plaintiffs then filed a second lawsuit, again as representatives of a putative class of royalty owners in which they assert their claims that the defendants have engaged in systematic mismeasurement of the Btu content of natural gas for more than 25 years. In both lawsuits, the plaintiffs seek compensatory damages, along with statutory penalties, treble damages, interest, costs and fees. In September 2009, the district court in Stevens County, Kansas, denied plaintiffs' request for class certification of their case and, in March 2010, denied the plaintiffs' request for reconsideration of that order. The district court subsequently signed an order dismissing without prejudice certain defendants from both lawsuits, including the remaining CenterPoint Energy defendants.

Other Proceedings

The Partnership is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(11) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Combined Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data. A market approach is utilized to value the Partnership's Level 3 assets or liabilities.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable and current notes payable, are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The fair value of each debt instrument is determined by evaluating the Partnership's borrowing rates for debt instruments with comparable maturities (level 3 inputs).

	December 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long term notes payable—affiliated	$ 1,009	$1,232	$ 646	$ 817

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). At December 31, 2012 and 2011, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

(12) Reportable Business Segments

The Partnership's determination of reportable business segments considers the strategic operating units under which CenterPoint Energy manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting policies except that some executive benefit costs have not been allocated to business segments. The Partnership uses operating income as the measure of profit or loss for its business segments.

The Partnership's reportable business segments include Transportation and Storage and Gathering and Processing. The Transportation and Storage business segment includes the interstate natural gas pipeline operations. The Gathering and Processing business segment includes the non-rate regulated natural gas gathering, processing and treating operations.

Long-lived assets include net property, plant and equipment, net goodwill and other intangibles and investments in equity method affiliates. Intersegment sales are eliminated in combination.

Financial data for business segments and products and services are as follows:

Year Ended December 31, 2012	Transportation and Storage[1]	Gathering and Processing[2]	Eliminations	Total
		(In millions)		
Revenues[3][4]	$ 502	$ 502	$ (52)	$ 952
Cost of goods sold (excluding depreciation and amortization)	55	124	(50)	129
Operation and maintenance	155	114	(2)	267
Depreciation and amortization	56	50	—	106
Taxes other than income	29	5	—	34
Operating income	$ 207	$ 209	$ —	$ 416
Total assets	$ 4,052	$ 2,439	$ (9)	$6,482
Capital expenditures	$ 132	$ 51	$ —	$ 183

Year Ended December 31, 2011	Transportation and Storage[1]	Gathering and Processing[2]	Eliminations	Total
		(In millions)		
Revenues[3][4]	$ 553	$ 415	$ (36)	$ 932
Cost of goods sold (excluding depreciation and amortization)	65	70	(34)	101
Operation and maintenance	154	111	(2)	263
Depreciation and amortization	54	37	—	91
Taxes other than income	32	5	—	37
Operating income	$ 248	$ 192	$ —	$ 440
Total assets	$ 3,869	$ 1,933	$ (6)	$5,796
Capital expenditures	$ 99	$ 201	$ —	$ 300

Year Ended December 31, 2010	Transportation and Storage(1)	Gathering and Processing(2)	Eliminations	Total
		(In millions)		
Revenues(3)(4)	$ 601	$ 340	$ (70)	$ 871
Cost of goods sold (excluding depreciation and amortization)	91	75	(68)	98
Operation and maintenance	155	80	(2)	233
Depreciation and amortization	52	25	—	77
Taxes other than income	33	4	—	37
Operating income	$ 270	$ 156	$ —	$ 426
Total assets	$ 3,674	$ 1,802	$ (13)	$5,463
Capital expenditures	$ 102	$ 668	$ —	$ 770

(1) Transportation and Storage recorded equity income of $26 million, $21 million and $19 million in the years ended December 31, 2012, 2011 and 2010, respectively, from its 50% interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of equity method affiliates under the Other Income (Expense) caption. Transportation and Storage's investment in SESH was $404 million, $409 million and $413 million as of December 31, 2012, 2011 and 2010, respectively, and is included in Investments in equity method affiliates.

(2) Gathering and Processing recorded equity income of $5 million, $10 million and $10 million for the years ended December 31, 2012, 2011 and 2010, respectively, from its 50% interest in a jointly-owned gas processing plant. These amounts are included in Equity in earnings of equity method affiliates under the Other Income (Expense) caption. Gathering and Processing's investment in the jointly-owned gas processing plant was $0 million and $63 million as of December 31, 2012 and 2011, respectively, and is included in Investments in equity method affiliates.

(3) Revenues are comprised of gas transportation, storage, gathering and processing revenues.

(4) The Partnership revenues from affiliates of CenterPoint Energy accounted for 14%, 15% and 13% of revenues in 2012, 2011 and 2010, respectively. The Partnership had no external customers accounting for 10% or more of revenues in periods shown. For further discussion of related party transactions, see Note 8.

(13) Subsequent Events

The Partnership determined there were no events which occurred subsequent to December 31, 2012, which should be disclosed or recognized in the financial statements, except as discussed in Note 1 and below. The evaluation was performed through April 30, 2013, the date the financial statements were issued.

In March 2013, Enable Bakken Crude Services, LLC (Enable Bakken), the Partnership's direct, wholly owned subsidiary, entered into a long-term agreement with XTO Energy Inc. (XTO), a subsidiary of Exxon-Mobil Corporation, to provide gathering services for certain of XTO's crude oil production through a new crude oil gathering and transportation pipeline system in North Dakota's liquids-rich Bakken shale formation. The agreement with XTO was entered into pursuant to the open season announced by Enable Bakken in February 2013. Under the terms of the agreement, which includes volume commitments, Enable Bakken will provide service to XTO over a gathering system to be constructed by Enable Bakken in Dunn and McKenzie counties in North Dakota with a capacity of up to 19,500 barrels per day. Enable Bakken estimates that the construction of these facilities may cost as much as $125 million.

(14) Correction of the Presentation of Noncontrolling Interest

The Partnership has recorded an adjustment to correct the presentation of noncontrolling interest in its Combined Balance Sheets as of December 31, 2012 and 2011 for a consolidated investment in a pipeline. The effect of this adjustment decreases Other Liabilities and increases Noncontrolling Equity Interest by approximately $6 million as of December 31, 2012 and 2011. As Net Income Attributable to Noncontrolling Interest is less than $500,000 for the years ended December 31, 2012, 2011 and 2010, it is not presented separately in the Statements of Combined Income.

ENABLE MIDSTREAM PARTNERS, LP

CONDENSED COMBINED AND CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Nine Months Ended September 30, 2013	2012
	(In millions)	
Revenues (including revenues from affiliates (Note 10))	$ 1,665	$ 686
Cost of Goods Sold, excluding depreciation and amortization (including expenses from affiliates (Note 10))	827	75
Operating Expenses:		
Operation and maintenance (including expenses from affiliates (Note 10))	302	191
Depreciation and amortization	148	78
Impairment	12	—
Taxes other than income taxes	37	28
Total Operating Expenses	499	297
Operating Income	339	314
Other Income (Expense):		
Interest expense (including expenses from affiliates (Note 10))	(53)	(65)
Equity in earnings of equity method affiliates	12	25
Interest income—affiliated companies	9	15
Step acquisition gain	—	136
Other, net	—	1
Total Other Income (Expense)	(32)	112
Income Before Income Taxes	307	426
Income tax expense (benefit)	(1,195)	160
Net Income	$ 1,502	$ 266
Less: Net income attributable to noncontrolling interest	2	—
Net Income attributable to Enable Midstream Partners, LP	$ 1,500	$ 266

See Notes to the Unaudited Condensed Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

CONDENSED COMBINED AND CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
	(In millions)	
Net income	$ 1,502	$ 266
Other comprehensive income, net of tax:		
Adjustment to pension and other postretirement plans (net of tax of $0 and $0)	—	1
Other comprehensive income	—	1
Comprehensive income	1,502	267
Less: Comprehensive income attributable to noncontrolling interest	2	—
Comprehensive income attributable to Enable Midstream Partners, LP	$ 1,500	$ 267

See Notes to the Unaudited Condensed Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

CONDENSED COMBINED AND CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(In millions)	
Current Assets:		
Cash and cash equivalents	$ 24	$ —
Accounts receivable	265	78
Accounts receivable—affiliated companies	24	25
Notes receivable—affiliated companies	4	479
Inventory	89	57
Taxes receivable	—	45
Deferred income tax assets	—	31
Gas imbalances	10	—
Other current assets	9	24
Total current assets	425	739
Property, Plant and Equipment:		
Property, plant and equipment	9,457	5,175
Less accumulated depreciation and amortization	626	470
Property, plant and equipment, net	8,831	4,705
Other Assets:		
Intangible assets, net	392	—
Goodwill	1,061	629
Investment in equity method affiliates	200	405
Regulatory assets, net	3	—
Other	38	4
Total other assets	1,694	1,038
Total Assets	$ 10,950	$ 6,482

See Notes to the Unaudited Condensed Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

CONDENSED COMBINED AND CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(In millions)	
Current Liabilities:		
Accounts payable	$ 289	$ 83
Accounts payable—affiliated companies	34	28
Current portion of long-term debt	205	—
Notes payable—affiliated companies	—	753
Taxes accrued	47	25
Gas imbalances	8	7
Other	39	26
Total current liabilities	622	922
Other Liabilities:		
Accumulated deferred income taxes, net	—	1,272
Notes payable—affiliated companies	363	1,009
Benefit obligations	—	21
Regulatory liabilities	21	16
Other	31	21
Total other liabilities	415	2,339
Long-Term Debt	1,727	—
Commitments and Contingencies (Note 11)		
Partners' Capital:		
Partners' Capital	8,152	3,221
Accumulated other comprehensive loss	—	(6)
Total Enable Midstream Partners, LP Partners' Capital	8,152	3,215
Noncontrolling interest	34	6
Total Partners' Capital	8,186	3,221
Total Liabilities and Partners' Capital	$ 10,950	$ 6,482

See Notes to the Unaudited Condensed Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

CONDENSED COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2013	2012
	(In millions)	
Cash Flows from Operating Activities:		
Net income	$ 1,502	$ 266
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	148	78
Deferred income taxes	(1,197)	132
Impairments	12	—
Step acquisition gain	—	(136)
Gain on sale/retirement of assets	2	—
Equity in earnings of equity method affiliates, net of distributions	8	6
Changes in other assets and liabilities:		
Accounts receivable, net	(37)	(40)
Accounts receivable—affiliated companies	(2)	8
Inventory	(9)	—
Taxes receivable	20	23
Other current assets	20	(3)
Other assets	(7)	(1)
Accounts payable	3	3
Accounts payable—affiliated companies	7	21
Other current liabilities	11	(5)
Other liabilities	(3)	—
Other, net	(6)	5
Net cash provided by operating activities	472	357
Cash Flows from Investing Activities:		
Capital expenditures, net of acquisitions	(366)	(116)
Acquisitions, net of cash acquired	—	(361)
Decrease (increase) in notes receivable from affiliates	434	(80)
Investment in equity method affiliates	—	(6)
Other, net	(5)	(13)
Net cash provided by (used in) investing activities	63	(576)
Cash Flows from Financing Activities:		
Proceeds from long term debt, net of issuance costs	1,046	—
Proceeds from line of credit	590	—
Repayment of line of credit	(447)	—
Increase (decrease) of notes payable—affiliated companies	(1,542)	221
Repayment of advance with affiliated companies	(140)	—
Capital contributions from partners	43	—
Distributions to partners	(61)	—
Net cash provided by (used in) financing activities	(511)	221
Net Increase in Cash and Cash Equivalents	24	2
Cash and Cash Equivalents at Beginning of Period	—	—
Cash and Cash Equivalents at End of Period	$ 24	$ 2

See Notes to the Unaudited Condensed Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

CONDENSED COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(Unaudited)

	Nine Months Ended September 30, 2013	2012
	(In millions)	
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest, net of capitalized interest	$ 52	$ 65
Income taxes (refunds), net	(9)	24
Non-cash transactions:		
Accounts payable related to capital expenditures	$ 41	$ 31
Acquisition of Enogex (Note 3)	3,787	—

See Notes to the Unaudited Condensed Combined and Consolidated Financial Statements

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ENABLE MIDSTREAM PARTNERS, LP

CONDENSED COMBINED AND CONSOLIDATED STATEMENTS OF
ENABLE MIDSTREAM PARTNERS, LP PARENT NET EQUITY AND PARTNERS' CAPITAL
(Unaudited)

	Partners' Capital		Parent Net Investment	Accumulated Other Comprehensive Loss	Total Enable Midstream Partners, LP Partners' Capital	Noncontrolling Interest	Total Partners' Capital
	Units	Value	Value	Value	Value	Value	Value
	(In millions)						
Balance as of December 31, 2011	—	—	$ 2,904	$ (6)	$ 2,898	$ 6	$ 2,904
Net income	—	—	266	—	266	—	266
Other comprehensive income	—	—	—	1	1	—	1
Net transfers from parent	—	—	2	—	2	—	2
Balance as of September 30, 2012	—	—	$ 3,172	$ (5)	$ 3,167	$ 6	$ 3,173
Balance as of December 31, 2012	—	—	$ 3,221	$ (6)	$ 3,215	$ 6	$ 3,221
Net income	—	—	1,326	—	1,326	—	1,326
Contributions from (Distributions to) CenterPoint Energy prior to formation (Note 1)	—	—	(295)	6	(289)	—	(289)
Balance as of April 30, 2013	—	—	$ 4,252	$ —	$ 4,252	$ 6	$ 4,258
Conversion to a limited partnership	291	$4,252	($ 4,252)	—	—	—	—
Issuance of units upon acquisition of Enogex on May 1, 2013	208	$3,787	—	—	$ 3,787	$ 26	$ 3,813
Net income (loss)	—	174	—	—	174	2	176
Distributions to partners	—	(61)	—	—	(61)	—	(61)
Balance as of September 30, 2013	499	$8,152	$ —	$ —	$ 8,152	$ 34	$ 8,186

See Notes to the Unaudited Condensed Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

NOTES TO THE UNAUDITED CONDENSED COMBINED AND CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners (Partnership) is a private limited partnership formed on May 1, 2013 by CenterPoint Energy, Inc. (CenterPoint Energy), OGE Energy Corp. (OGE Energy) and affiliates of ArcLight Capital Partners, LLC (ArcLight), pursuant to the terms of the Master Formation Agreement dated March 14, 2013 (MFA). The Partnership is a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. The Partnership's assets and operations are organized into two business segments: (i) gathering and processing, which primarily provides natural gas and crude oil gathering, processing and fractionation services for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. The natural gas gathering and processing assets are strategically located in four states and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. This segment also includes an emerging crude oil gathering business in the Bakken shale formation, principally located in the Williston basin. The natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

As of September 30, 2013, CenterPoint Energy, OGE Energy and ArcLight hold approximately 58.3%, 28.5% and 13.2%, respectively, of the limited partner interests in the Partnership. The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership's General Partner on an annual or continuing basis and may not remove the Partnership's General Partner without at least 75% vote by all unitholders, including all units held by the Partnership's limited partners, and General Partner and its affiliates, voting together as a single class.

The Partnership is controlled equally by CenterPoint Energy and OGE Energy, who each have 50 percent of the management rights of the General Partner. The General Partner was established by CenterPoint Energy and OGE Energy to govern the Partnership and has no other operating activities. The General Partner is initially governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy and OGE Energy. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, CenterPoint Energy and OGE Energy deconsolidated their interests in the Partnership and Enogex LLC (Enogex), respectively.

CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in any incentive distribution rights to be held by the General Partner following an initial public offering of the Partnership's common units. In addition, for a period of time prior to the initial public offering, ArcLight will have protective approval rights over certain material activities of the Partnership, including material increases in capital expenditures and certain equity issuances, entering into transactions with related parties and acquiring, pledging or disposing of certain material assets.

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. As a result of the conversion to a partnership immediately prior to formation, CenterPoint Energy assumed all outstanding current income tax liabilities and the Partnership derecognized the deferred income tax assets and liabilities by recording an income tax benefit of $1.24 billion. Consequently, the Combined and Consolidated Statements of Income does not include an income tax provision on income earned on or after May 1, 2013 (other than Texas state margin taxes). See Note 12 for further discussion of the Partnership's income taxes.

Prior to May 1, 2013, the financial statements of the Partnership include Enable Gas Transmission, LLC (EGT), Enable—Mississippi River Transmission, LLC (MRT), and the non-rate regulated natural gas gathering, processing and treating operations, which were under common control by CenterPoint Energy, and a 50% interest in Southeast Supply Header, LLC (SESH). As discussed in Note 1 under "Parent Net Equity and Partners' Capital," through the Partnership formation on May 1, 2013, CenterPoint Energy retained certain assets and liabilities and related balances in accumulated other comprehensive less, historically held by the Partnership such as certain intercompany notes payable to CenterPoint Energy and benefit plan obligations. Additionally, the Partnership distributed 25.05% of the interest in SESH to CenterPoint Energy, subject to future acquisition by the Partnership through put and call options discussed in Note 6. On May 1, 2013, OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the Partnership in exchange for limited partner interests and, for OGE Energy only, interests in the General Partner. The Partnership concluded that the Partnership formation on May 1, 2013 was considered a business combination, and for accounting purposes, the Partnership was the acquirer of Enogex. Subsequent to May 1, 2013, the financial statements of the Partnership are consolidated to reflect the acquisition of Enogex, and the remaining 24.95% interest in SESH. See Note 3 for further discussion of the acquisition of Enogex.

In addition, at September 30, 2013, as a result of the acquisition of Enogex on May 1, 2013, the Partnership holds a 50% ownership interest in Atoka Midstream LLC (Atoka). At September 30, 2013, the Partnership consolidated Atoka in its Condensed Combined and Consolidated Financial Statements as Enable Oklahoma acted as the managing member of Atoka and had control over the operations of Atoka.

These condensed combined and consolidated financial statements are unaudited, omit certain financial statement disclosures and should be read with the audited combined financial statements of the Partnership for the years ended December 31, 2012, 2011 and 2010.

Basis of Presentation

These condensed combined and consolidated financial statements and related notes of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States. For accounting and financial reporting purposes, (i) the formation of the Partnership is considered a contribution by CenterPoint Energy and is reflected at CenterPoint Energy's historical cost as of May 1, 2013 and (ii) the Partnership acquired Enogex on May 1, 2013.

These condensed combined and consolidated financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy for the Partnership until May 1, 2013 and may not necessarily be indicative of the condition that would have existed or the results of operations if the Partnership had been operated as a separate and unaffiliated entity. All of Partnership's combined entities were under common control and management for the periods presented until May 1, 2013, and all intercompany transactions and balances are eliminated in combination and consolidation, as applicable. Beginning on May 1, 2013, the Partnership consolidated Enogex and all previously combined entities of the Partnership.

These condensed combined and consolidated financial statements and the related financial statement disclosures reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods. Amounts reported in the Partnership's Condensed Combined and Consolidated Statements of Income are not necessarily indicative of amounts expected for a full-year period due to the effects of, among other things, (a) seasonal fluctuations in demand for energy and energy services, (b) changes in energy commodity prices, (c) timing of maintenance and other expenditures and (d) acquisitions and dispositions of businesses, assets and other interests.

For a description of the Partnership's reportable business segments, see Note 13.

Enable Midstream Partners, LP Parent Net Equity and Partners' Capital

Prior to May 1, 2013, Enable Midstream Partners, LP Parent Net Equity on the Condensed Combined Balance Sheet represents the investment of CenterPoint Energy in the Partnership. On April 30, 2013 immediately prior to formation of the limited partnership, while under common control, CenterPoint Energy completed equity transactions with the Partnership, whereby CenterPoint Energy made a cash contribution to the Partnership and retained certain assets and liabilities previously held by the Partnership, all of which were deemed to be transfers of net assets not constituting a transfer of a business, as follows:

	Amounts retained prior to May 1, 2013 (In millions)
Contributions from (Distributions to) CenterPoint Energy	
Cash	$ 40
Pension and postretirement plans	22
Deferred financing cost	6
Investment in 25.05% of SESH (see Note 6)	(197)
Increase in Notes payable—affiliated companies (see Note 10)	(143)
Decrease in Notes receivable—affiliated companies (see Note 10)	(45)
Income tax obligations, net	28
Net distributions to CenterPoint Energy prior to formation	$ (289)

Effective May 1, 2013, Enable Midstream Partners, LP Partners' Capital on the Condensed Consolidated Balance Sheet represents the net amount of capital, accumulated net income, contributions and distributions impacting the investments of CenterPoint Energy, OGE Energy, and ArcLight in the Partnership. On August 14, 2013, the Partnership distributed $61 million to the unitholders of record as of July 1, 2013.

Assessing Impairment of Long-lived Assets (including Intangible Assets) and Goodwill

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets.

Upon formation as a private partnership on May 1, 2013, management of the Partnership reassessed the long-term strategy related to the Service Star business line, a component of the Gathering and Processing business segment which provides measurement and communication services to third parties. Based on forecasted future undiscounted cash flows, management determined that the carrying value of the Service Star assets were not fully recoverable. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the nine months ended September 30, 2013 the Partnership recognized a $12 million impairment, consisting of a $10 million write-down of property, plant and equipment and a $2 million write-down of materials and supplies inventory considered either excess or obsolete.

The Partnership assesses its goodwill for impairment at least annually by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership tested its goodwill for impairment on May 1, 2013 upon formation and following formation intends to begin testing annually on October 1. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. The Partnership performs its goodwill impairment testing one level below the Transportation and Storage and Gathering and Processing business segment level at the operating segment level. The partnership recorded no impairments of goodwill in the nine months ended September 30, 2013 and 2012.

Revenues

Revenues for gathering, processing, transportation and storage services for the partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts Receivable on the Combined or Consolidated Balance Sheets and in Revenues on the Combined and Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

The partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The partnership has no material deferred revenues on the Combined or Consolidated Balance Sheets as of September, 30 2013 or December 31, 2012.

Natural Gas Purchases

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Combined or Consolidated Balance Sheets and in Cost of Goods Sold, excluding Depreciation and Amortization on the Combined and Consolidated Statements of Income.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or market. During the nine months ended September 30, 2013, the Partnership recorded write-downs to market value related to materials and supplies inventory of $2 million associated with the Service Star business line impairment discussed above. No write-downs were recorded in the nine months ended September 30, 2012. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to Operation and maintenance expense on the Combined and Consolidated Statements of Income or capitalized to Property, plant and equipment on the Combined or Condensed Balance Sheets when installed.

Natural gas inventory is held, through the transportation and storage business segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the gathering and processing business segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or market. During the nine months ended September 30, 2013, the Partnership recorded write-downs to market value related to natural gas and natural gas liquids inventory of $4 million. No write-downs were recorded in the nine months ended September 30, 2012. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of Goods Sold, excluding depreciation and amortization on the Combined and Consolidated Statements of Income.

	September 30, 2013	December 31, 2012
	(In millions)	
Materials and Supplies	$ 67	$ 56
Natural gas and natural gas liquids inventories	22	1
Total	$ 89	$ 57

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind depending on contractual terms. The Partnership values all imbalances at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value.

Accumulated Other Comprehensive Loss

There were no material changes in the components of accumulated other comprehensive loss attributable to the Partnership during the nine months ended September 30, 2013. At both September 30, 2013 and December 31, 2012, there was no accumulated other comprehensive loss related to Partnership's noncontrolling interest.

No significant amounts were reclassified out of accumulated other comprehensive loss to net income during the nine months ended September 30, 2013 and 2012.

(2) New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" (ASU 2013-02). The objective of ASU 2013-02 is to improve the transparency of changes in other comprehensive income and items reclassified out of Accumulated Other Comprehensive Income in financial statements. This new guidance is effective for a reporting entity's first reporting period beginning after December 15, 2012 and should be applied prospectively. The Partnership's adoption of this new guidance on January 1, 2013 did not have a material impact on its financial position, results of operations or cash flows.

In December 2011 and January 2013, the FASB issued Accounting Standards Update No. 2011-11, "Disclosures About Offsetting Assets and Liabilities" (ASU 2011-11) and No. 2013-01, "Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities" (ASU 2013-01), respectively. The objective of ASU 2011-11 is to enhance disclosures about the nature of an entity's rights of setoff and related arrangements associated with its financial instruments and derivative instruments. The objective of ASU 2013-01 is to clarify which instruments and transactions are subject to ASU 2011-11. Both ASU 2011-11 and ASU 2013-01 are effective for a reporting entity's first reporting period beginning on or after January 1, 2013 and should be applied retrospectively. The Partnership's adoption of this new guidance on January 1, 2013 did not have a material impact on its combined and consolidated financial position, results of operations or cash flows.

Management believes that other recently issued standards, which are not yet effective, will not have a material impact on the Partnership's combined and consolidated financial position, results of operations or cash flows upon adoption.

(3) Acquisition of Enogex

Under the acquisition method, the fair value of the consideration transferred by the Partnership to OGE Energy and ArcLight for the contribution of Enogex in exchange for interest in the Partnership is allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their estimated fair value. Enogex's assets, liabilities and equity are recorded at their estimated fair value as of May 1, 2013, and beginning on May 1, 2013, the Partnership consolidated Enogex. The Partnership expects to complete the purchase price allocation for these transactions in the fourth quarter of 2013.

On May 1, 2013, in accordance with the MFA, CenterPoint Energy, OGE Energy, and ArcLight received 291,002,583 common units, 141,956,176 common units, and 65,908,224 common units, respectively, representing limited partner interests in the Partnership. The fair value of consideration transferred to OGE Energy and ArcLight in exchange for the contribution of Enogex consists of the fair value of the limited and general partner interests. The Partnership utilized the market approach to estimate the fair value of the limited partner interests, general partner interests and Atoka, also giving consideration to alternative methods such as the income and cost approaches as it relates to the underlying assets and liabilities. The primary inputs for the market valuation are the historical and current year forecasted cash flows and market multiple. The primary inputs for the income approach are forecasted cash flows and the discount rate. The primary inputs for the cost approach are costs for similar assets and ages of the assets. All fair value measurements of assets acquired and liabilities assumed are based on a combination of inputs that are not observable in the market and thus represent Level 3 inputs.

The Partnership incurred no acquisition related costs in the Condensed Combined and Consolidated Statement of Income based upon the terms in the MFA.

The following table summarizes the amounts recognized by the Partnership for the estimated fair value of assets acquired and liabilities assumed for the acquisition of 100% interest Enogex as of May 1, 2013 and is reconciled to the consideration transferred by the Partnership (in millions):

	Amounts Recognized as of May 1, 2013
Assets	
Current Assets	$ 192
Property, plant and equipment	3,918
Goodwill	432
Other intangible assets	403
Other assets	22
Total assets	4,967
Liabilities	
Current Liabilities	$ 393
Long-term debt	745
Other liabilities	16
Total liabilities	1,154
Less: Noncontrolling interest at fair value	26
Fair value of consideration transferred	$ 3,787

The amounts of Enogex's revenue, operating income, net income and net income attributable to Enable Midstream Partners, LP included in the Partnership's Condensed Combined and Consolidated Statement of Income for the period from May 1, 2013 through September 30, 2013 is as follows (in millions):

Revenues	$ 861
Operating income	$ 63
Net income	$ 54
Net income attributable to Enable Midstream Partners, LP	$ 52

See Note 6 for discussion of the Partnership's acquisition of Waskom during 2012.

Impact on Depreciation

The property, plant and equipment acquired from Enogex have differing weighted average useful lives from the existing assets of the Partnership. These assets will be depreciated over a weighted average estimated useful life of 32 years.

Pro forma Results of Operations

The Partnership's pro forma results of operations in the combined entity had the acquisition of Enogex been completed on January 1, 2012 are as follows (in millions):

	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Pro forma results of operations:		
Pro forma revenues	$ 2,296	$ 1,866
Pro forma operating income	$ 356	$ 425
Pro forma net income	$ 1,522	$ 360
Pro forma net income attributable to Enable Midstream Partners, LP	$ 1,520	$ 358

The pro forma consolidated results of operations include adjustments to:

- Include the historical results of Enogex beginning on January 1, 2012;
- Include incremental depreciation and amortization incurred on the step-up of Enogex's assets;
- Include adjustments to revenue and cost of sales to reflect Enogex purchase price adjustments for the recurring impact of certain loss contracts and deferred revenues; and
- Include a reduction to interest expense for recognition of a premium on Enogex's fixed rate senior notes.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the consolidated operations.

(4) Intangible Assets, Net

Prior to May 1, 2013, the Partnership did not have any intangible assets. Associated with the acquisition of Enogex, the Partnership recorded $403 million in intangible assets associated with customer relationships. Intangible assets by intangible asset class are as follows as of September 30, 2013 (in millions):

	Acquisition of Enogex	Accumulated Amortization	Net Intangible Assets
Customer relationships	$ 403	$ 11	$ 392
Total	$ 403	$ 11	$ 392

The Partnership determined that intangible assets have a weighted average useful life of 15 years for customer relationships as of May 1, 2013. Intangible assets do not have any significant residual value or renewal existing terms. There are no amounts of intangible assets with infinite useful lives.

Amortization of intangible assets is computed using the straight-line method over the respective lives of the intangible assets. Amortization expense in the nine months ended September 30, 2013 is $11 million. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years (in millions).

	2014	2015	2016	2017	2018
Expected amortization of intangible assets	$27	$27	$27	$27	$27

(5) Goodwill

The excess of the consideration transferred over the fair value of the net assets acquired is allocated to goodwill. The goodwill arising from the acquisition of Enogex consists largely of the synergies and economies of scale expected from combining the operations of the Partnership and Enogex. The Partnership determined that its reporting units consist of its operating segments. Goodwill by reportable segment for 2013 is as follows (in millions):

	Gathering and Processing	Transportation and Storage	Total
Balance at January 1	$ 50	$ 579	$ 629
Acquisition of Enogex	394	38	432
Balance at September 30	$ 444	$ 617	$1,061

The Partnership does not amortize goodwill but instead annually assesses goodwill for impairment. The Partnership performed an interim test upon formation as a limited partnership on May 1, 2013 and its annual impairment test in the third quarter of 2012 and determined that no impairment charge for goodwill was required in the nine months ended September 30, 2013 and 2012, respectively. Effective October 1, 2013, the Partnership will perform its annual impairment tests on October 1.

(6) Investments in Equity Method Affiliates

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence. Until May 1, 2013, the Partnership held a 50% investment in SESH, a 270-mile interstate natural gas pipeline, which was accounted for as an investment in equity method affiliates. On May 1, 2013, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, retaining a 24.95% interest in SESH.

Following the distribution of SESH, CenterPoint Energy indirectly owns 25.05% interest in SESH that may be contributed to Partnership in the future, upon exercise of certain put or call rights, under which CenterPoint Energy would contribute to the Partnership CenterPoint Energy's retained interest in SESH at a price equal to the fair market value of such interest at the time the put right or call right is exercised (which may be no earlier than May 2014 and May 2015 for 24.95% and 0.1% interest, respectively). If CenterPoint Energy were to exercise such put right or the Partnership were to exercise such call right, CenterPoint Energy's retained interest in SESH would be contributed to the Partnership in exchange for consideration consisting of 8,086,945 and 32,413 limited partnership units for 24.95% and 0.1% interest in SESH, respectively, and, subject to certain restrictions, a cash payment, payable either from CenterPoint Energy to the Partnership or from the Partnership to CenterPoint Energy, in an amount such that the total consideration exchanged is equal in value to the fair market value of the contributed interest in SESH.

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Prior to July 2012, the Partnership owned a 50% interest in Waskom, a natural gas processing plant, which was accounted as an investment in equity method affiliates.

On July 31, 2012, the Partnership purchased the 50% interest that it did not already own in Waskom, as well as other gathering and related assets from a third-party for approximately $273 million in cash. The amount of the purchase price allocated to the acquisition of the 50% interest in Waskom was approximately $201 million, with the remaining purchase price allocated to the other gathering assets. The $273 million purchase price was allocated to the fair value of assets received as follows: $253 million to property, plant and equipment; $16 million to goodwill; and the remaining balance to other assets and liabilities. The original 50% interest held by Partnership in Waskom had a fair value of approximately $201 million prior to its acquisition of the additional 50% interest in Waskom, based on a discounted cash flow methodology (a level 3 valuation technique for which the key inputs are the discount rate and operating cash flow projections). The purchase of the additional 50% interest in Waskom was determined to be a business combination achieved in stages, and as such the Partnership recorded a pre-tax gain of approximately $136 million and goodwill of $8 million on July 31, 2012, which is the result of Partnership remeasuring its original 50% interest in Waskom to fair value. As a result of the purchase, Partnership combined its wholly owned investment in Waskom beginning on July 31, 2012, which included goodwill totaling $24 million, consisting of $17 million related to Waskom (including the re-measurement of its existing 50% interest) and $7 million related to the other gathering and related assets. On May 1, 2013 CenterPoint Energy contributed a 100% interest in Waskom to the Partnership.

Investment in Equity Method Affiliates:

	September 30, 2013	December 31, 2012
	(In millions)	
SESH	$ 199	$ 404
Other	1	1
Total	$ 200	$ 405

Equity in Earnings of Equity Method Affiliates:

	Nine months ended September 30,	
	2013	2012
	(In millions)	
SESH(1)	$ 12	$ 20
Waskom(2)	—	5
Total	$ 12	$ 25

(1) Until May 1, 2013, the combined results of operations for Partnership reflect a 50% interest in SESH, as historically combined in the Partnership's financial statements. On May 1, 2013, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, retaining a 24.95% interest in SESH.

(2) On July 31, 2012, Waskom became a wholly owned subsidiary of the Partnership. Beginning on August 1, 2012, Waskom's operating results are combined or consolidated, as appropriate, in the Condensed Combined and Consolidated Statement of Income.

Summarized financial information of SESH is presented below:

	Nine months ended September 30, 2013	2012
	(In millions)	
Income Statements:		
Revenues	$ 81	$ 82
Operating income	49	54
Net income	34	39

Summarized financial information of Waskom is presented below:

	Nine months ended September 30, 2012[(a)]
	(In millions)
Income Statements:	
Revenues	$ 77
Operating income	11
Net income	11

(a) Reflects Waskom's income statement through July 31, 2012, the date Waskom became a wholly owned subsidiary of the Partnership. Beginning on August 1, 2012, Waskom's operating results are combined in the Condensed Combined and Consolidated Statement of Income.

(7) Debt

Prior to May 1, 2013, the Partnership's debt was all payable to affiliates, which is discussed in Note 10 as notes payable—affiliated companies. The Partnership's third party debt effective May 1, 2013 follows:

On May 1, 2013, the Partnership entered into a $1.05 billion three-year senior unsecured term loan facility (Term Loan Facility), the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership's obligations under the Term Loan Facility, which guarantee is subordinated to all senior debt of such wholly owned subsidiary of CenterPoint Energy.

On May 1, 2013, the Partnership also entered into a $1.4 billion, five-year senior unsecured revolving credit facility (Revolving Credit Facility) in accordance with the terms of the MFA, discussed in Note 1. As of September 30, 2013, there was $142 million in principal advances and $1 million in letters of credit outstanding under the Revolving Credit Facility.

The Term Loan Facility and the Revolving Credit Facility each permit outstanding borrowings to bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of September 30, 2013, the applicable margin for LIBOR-based borrowings under the Term Loan Facility and the Revolving Credit Facility was 1.625% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of September 30, 2013, the commitment fee under the Revolving Credit Facility was 0.25% per annum based on the Partnership's credit ratings.

Effective May 1, 2013, the Partnership's debt includes Enable Oklahoma's $200 million of 6.875% senior notes due July of 2014 and $250 million of 6.25% senior notes due March of 2020 (collectively, the Enable Oklahoma Senior Notes). The Enable Oklahoma Senior Notes have a $40 million unamortized premium at September 30, 2013, of which $5 million relates to the senior notes due July of 2014 and $35 million relates to the senior notes due March of 2020. Additionally, the Partnership's debt includes Enable Oklahoma's $250 million variable rate term loan (Enable Oklahoma Term Loan). The Enable Oklahoma Term Loan permits outstanding borrowings to bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at Enable Oklahoma's election, plus an applicable margin. The applicable margin is based on Enable Oklahoma's applicable credit ratings. As of September 30, 2013, the applicable margin for LIBOR-based borrowings under the Enable Oklahoma Term Loan was 1.50% based on Enable Oklahoma's credit ratings.

Unamortized debt expense of $10 million and zero at September 30, 2013 and December 31, 2012, respectively, is classified in Other Assets in the Combined and Consolidated Balance Sheets and are being amortized over the life of the respective debt. Unamortized premium on long-term debt of $40 million and zero at September 30, 2013 and December 31, 2012, respectively, is classified as either Long-Term Debt or Current Portion of Long-Term Debt, consistent with the underlying debt instrument, in the Combined and Consolidated Balance Sheets and are being amortized over the life of the respective debt.

At September 30, 2013, the Partnership and Enable Oklahoma were in compliance with all of their debt agreements.

(8) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Combined and Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the nine months ended September 30, 2013, there were no transfers between Level 1 and 2 and no Level 3 investments were held.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, short-term notes payable—affiliated companies, and other such financial instruments on the Condensed Combined and Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership's financial instruments at September 30, 2013 and December 31, 2012 (in millions). The Company had no material financial instruments measured at fair value on a recurring basis at September 30, 2013 and December 31, 2012.

	September 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-Term Debt				
Long-term notes payable—affiliated companies (Level 2)	$ 363	$ 362	$ 1,009	$1,232
Revolving Credit Facility (Level 2)	142	142	—	—
Term Loan Facility (Level 2)	1,050	1,050	—	—
Enable Oklahoma Term Loan (Level 2)	250	250	—	—
Enable Oklahoma Senior Notes (Level 2)(1)	490	478	—	—

(1) Includes $205 million of current portion as of September 30, 2013.

The fair value of the Partnership's Term Loan Facility and Long-term notes payable—affiliated companies, along with the Enable Oklahoma Senior Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

At September 30, 2013, the Partnership remeasured the Service Star assets at fair value, resulting in a $12 million impairment in the nine months ended September 30, 2013, as discussed in Note 1. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs.

At December 31, 2012, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Combined and Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation. The Partnership had no material commodity contracts recorded at fair value on its Condensed Combined and Consolidated Balance Sheet at September 30, 2013 and December 31, 2012.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis at September 30, 2013 (in millions):

	Gas Imbalances[(A)]	
	Assets[(B)]	Liabilities[(C)]
Significant other observable inputs (Level 2)	$ 8	$ 6

(A) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by Enable Oklahoma are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of September 30, 2013.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $2 million at September 30, 2013, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $2 million at September 30, 2013, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(9) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership's commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGLs put options and NGLs swaps are used to manage the Partnership's NGLs exposure associated with its processing agreements;
- natural gas swaps are used to manage the Partnership's keep-whole natural gas exposure associated with its processing operations and the Partnership's natural gas exposure associated with operating its gathering, transportation and storage assets; and

- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in the Condensed Combined and Consolidated Balance Sheets and earnings are recognized in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by Partnership's gathering and processing segment. All outstanding derivative instruments held by Partnership at December 31, 2012 are designated as normal purchase or normal sale during the periods presented.

The Partnership recognizes its non-exchange traded derivative instruments in the Condensed Combined and Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Combined Consolidated Balance Sheets.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may be forced to enter into alternative arrangements. In that event, Partnership's financial results could be adversely affected and the Partnership could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income (Loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Partnership measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Partnership designates as cash flow hedges derivatives used to manage commodity price risk exposure for the Partnership's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). The Partnership also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. The Partnership had no instruments designated as cash flow hedges at September 30, 2013 and December 31, 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Partnership includes the gain or loss on the hedged items in Revenues, offsetting the loss or gain on the related hedging derivative.

At September 30, 2013 and December 31, 2012, the Partnership had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated as Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in the Partnership's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings, unless designated as normal purchases or normal sales.

Quantitative Disclosures, Balance Sheet Presentation and Income Statement Presentation Related to Derivative Instruments

At September 30, 2013 and December 31, 2012 and for the nine months ended September 30, 2013 and 2012, the Partnership had no material derivative instruments to disclose.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Partnership's or Enable Oklahoma's senior unsecured debt ratings to a below investment grade rating, the Partnership or Enable Oklahoma would have been required to post no cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at September 30, 2013. The Partnership or Enable Oklahoma could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

(10) Related Party Transactions

The related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized and described below. There were no material related party transactions with other affiliates.

The Partnership's revenues from affiliated companies accounted for 9%, and 15% of revenues during the nine months ended September 30, 2013 and 2012, respectively. Amounts of revenues from affiliated companies included in the Partnership's Combined and Consolidated Statements of Income are summarized as follows:

	Nine months ended September 30,	
	2013	2012
	(In millions)	
Gas transportation and storage—CenterPoint Energy	$ 82	$100
Gas sales—CenterPoint Energy	48	—
Gas transportation and storage—OGE Energy[(1)]	20	—
Total revenues—affiliated companies	$150	$100

(1) The Partnership has contracts with OGE Energy to transport natural gas to OGE Energy's natural gas-fired generation facilities and store natural gas that are reflected in Partnership's Condensed Combined and Consolidated Statement of Income beginning on May 1, 2013.

Amounts of natural gas purchased from affiliated companies included in the Partnership's Condensed Combined and Consolidated Statements of Income are summarized as follows:

	Nine months ended September 30,	
	2013	2012
	(In millions)	
Cost of goods sold—CenterPoint Energy	$ 5	$ 1

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The Partnership recorded an expense from OGE Energy of $5 million for the period beginning May 1, 2013 and ended September 30, 2013 for electricity used to power the Partnership's electric compression assets, which is reflected in the Partnership's Condensed Combined and Consolidated Statement of Income as operation and maintenance expense beginning on May 1, 2013.

Prior to May 1, 2013, the Partnership had employees and reflected the associated benefit costs directly and not as corporate services. Under the terms of the MFA, effective May 1, 2013 the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership began reimbursing each CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until terminated with at least 90 days' notice by CenterPoint Energy or OGE Energy, respectively, or by the Partnership.

Prior to May 1, 2013, the Partnership received certain services and support functions from CenterPoint Energy described below. Under the terms of the MFA, effective May 1, 2013 the Partnership receives services and support functions from each CenterPoint Energy and OGE Energy under service agreements for an initial term ending on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of the General Partner. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, initially $44 million and $30 million, respectively.

The Partnership's operations are dependent on CenterPoint Energy's and OGE Energy's ability to perform under these service agreements, which include support functions for accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs, and human resources, as well as information technology services and other shared services such as corporate security, facilities management, office support services, and purchasing and logistics. The cost of these services has been charged directly to the Partnership through negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. In some instances, OGE Energy uses the "Distrigas" method to allocate operating costs to the Partnership. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the Staff of the Oklahoma Corporation Commission. CenterPoint Energy uses the Composite Ratio Formula which allocates costs incurred by a service company on behalf of its affiliates to those affiliates. This three-part formula consisting of gross margin, assets, and the number of employees applied 40%, 40% and 20% respectively, attempts to weight various aspects of each of the affiliates so that a fair distribution of the overhead cost is allocated to each affiliate member. These charges are not necessarily indicative of what would have been incurred had the Partnership not been an affiliate of CenterPoint Energy or OGE Energy.

Amounts charged to the Partnership by affiliates for seconded employees and corporate services, included primarily in operating and maintenance expenses in Partnership's Combined and Consolidated Statements of Income are as follows:

	Nine months ended September 30,	
	2013	2012
	(In millions)	
Seconded Employee Costs—CenterPoint Energy(1)	$ 58	$ —
Corporate Services—CenterPoint Energy(1)	30	27
Seconded Employee Costs—OGE Energy(2)	49	—
Corporate Services—OGE Energy(2)	11	—
Total corporate services and seconded employee expense	$148	$ 27

(1) Beginning on May 1, 2013, CenterPoint Energy assumed all employees of Partnership and seconded such employees to the Partnership. Therefore, costs historically incurred directly by Partnership for employment services are reflected as seconded employee costs subsequent to formation on May 1, 2013.

(2) Corporate services and seconded employee expenses from OGE Energy are reflected in the Condensed Statement of Combined and Consolidated Income beginning on May 1, 2013. With respect to the annual cap of $30 million for corporate services, $21 million has been incurred to date, including $10 million prior to the Partnership's acquisition of Enogex on May 1, 2013.

On July 1, 2009, OGE Energy and Enogex entered into hedging transactions to offset natural gas long positions at Enogex with short natural gas exposures at OGE Energy resulting from the cost of generation associated with a wholesale power sales contract. These transactions are for approximately 50,000 million British thermal unit per month from August 2009 to December 2013. These transactions are reflected in the Condensed Combined and Consolidated Statement of Income beginning on May 1, 2013.

Until May 1, 2013, the Partnership participated in a "money pool" through which it could borrow or invest with CenterPoint Energy on a short-term basis. Funding needs were aggregated and external borrowing or investing was based on the net cash position. The Partnership's money pool borrowings and investments were reflected in notes payable—affiliated companies and notes receivable—affiliated companies, respectively, in the Combined Balance Sheet as of December 31, 2012.

The notes receivable—affiliated companies as of December 31, 2012 include $434 million and $45 million investments in the money pool and other notes receivable, respectively, and bear an interest rate of 4.869% and 3.25%, respectively. Immediately prior to formation as a limited partnership on May 1, 2013, the Partnership received cash for repayment of the $434 million of investments in the money pool and received a contribution from CenterPoint Energy for the settlement of the $45 million of other notes receivable.

The Partnership has outstanding short-term and long-term notes payable – affiliated companies to CenterPoint Energy as presented below:

	September 30, 2013		December 31, 2012	
	Long-Term	Current	Long-Term	Current
	(In millions)			
Short-term notes payable—affiliated companies:				
Notes payable—affiliated companies(1)	$ —	$ —	$ —	$ 753
Long-term notes payable—affiliated companies:				
Notes payable—affiliated companies(2)	$ 363	$ —	$ 363	$ —
Notes payable—affiliated companies(3)	—	—	646	—
Total long-term notes payable—affiliated companies	$ 363	$ —	$ 1,009	$ —

(1) These notes were payable on demand to CenterPoint Energy and may be prepaid in full at any time without premium or penalty. Substantially all of these notes represented the Partnership's money pool borrowings. At December 31, 2012, the Partnership's money pool borrowings had an interest rate of 4.869%. These notes were repaid and terminated immediately prior to formation as a limited partnership on May 1, 2013.

(2) These notes are payable to CenterPoint Energy and mature in 2017. Notes having an aggregate principal amount of approximately $273 million bear a fixed interest rate of 2.10% and notes having an aggregate principal amount of approximately $90 million bear a fixed interest rate of 2.45%.

(3) These notes were payable to CenterPoint Energy, bear a fixed interest rate of 6.30% and mature in 2036. These notes were repaid and terminated immediately prior to formation as a limited partnership on May 1, 2013.

Prior to repayment of the $753 million and $646 million of short-term and long-term notes payable—affiliated companies, respectively, the Partnership assumed an additional $143 million through a distribution of the Partnership. In total, the repayment of notes payable—affiliated companies immediately prior to formation as a limited partnership on May 1, 2013 was $1.54 billion.

The Partnership recorded affiliated interest expense to CenterPoint Energy of $33 million and $65 million during the nine months ended September 30, 2013 and 2012, respectively, on notes payable—affiliated companies.

(11) Commitments and Contingencies

(a) Long-Term Agreements

Long-term Gas Gathering and Treating Agreements. The Partnership has long-term agreements with an affiliate of Encana Corporation (Encana) and an affiliate of Royal Dutch Shell plc (Shell) to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana.

Under the long-term agreements, Encana or Shell may elect to require the Partnership to expand the capacity of its gathering systems by up to an additional 1.3 Bcf per day. The Partnership estimates that the cost to expand the capacity of its gathering systems by an additional 1.3 Bcf per day would be as much as $440 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand system capacity.

Long-term Agreement with Exxon. In March 2013, Enable Bakken entered into a long-term agreement with an affiliate of Exxon-Mobil Corporation (Exxon), to provide gathering services for certain of Exxon's crude oil production through a new crude oil gathering and transportation pipeline system in North Dakota's liquids-rich Bakken shale. The agreement with Exxon was entered into pursuant to the open season announced by Enable Bakken in February 2013. Under the terms of the agreement, which includes volume commitments, Enable Bakken will provide service to Exxon over a gathering system to be constructed by Enable Bakken in Dunn and McKenzie counties in North Dakota with a capacity of up to 19,500 barrels per day. The Partnership estimates that the facilities will be placed in service in 2013 and 2014 and the construction of these facilities may cost as much as $110 million.

Operating Lease Obligations. The Partnership has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 (In millions)	2013	2014	2015	2016	2017	After 2017	Total
Noncancellable operating leases	$ 2	$ 6	$ 4	$ 2	$ —	$ —	$ 14

The Partnership currently occupies 134,219 square feet of office space at the executive offices under a lease that expires March 31, 2017. The lease payments are $11 million over the lease term which began April 1, 2012. This lease has rent escalations which increase after five and 10 years if the lease is renewed. These lease expenses are reflected in the Condensed Statement of Combined and Consolidated Income beginning on May 1, 2013.

The Partnership currently has 23 compression service agreements, of which three agreements are on a month-to-month basis, three agreements will expire in 2014, 16 agreements will expire in 2015 and two agreements will expire in 2016. The Partnership also has eight gas treating agreements, of which six agreements are on a month-to-month basis, one agreement will expire in 2013 and one agreement will expire in 2014. These lease expenses are reflected in the Condensed Statement of Combined and Consolidated Income beginning on May 1, 2013.

Other Purchase Obligations and Commitments. In 2004, Enable Oklahoma entered into a firm transportation service agreement with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of $7 million. Effective March 1, 2007, Enable Oklahoma and Cheyenne Plains amended the firm transportation service agreement to provide for EER to turn back 20,000 decatherms/day of its capacity beginning in January 2008 for the remainder of the term.

In 2006, Enable Oklahoma entered into a firm capacity agreement with Midcontinent Express Pipeline (MEP) for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers' access to capacity on Enable Oklahoma's system. The quantity of capacity subject to the MEP capacity agreement is currently 272 MMcf/d, with the quantity subject to being increased by mutual agreement pursuant to the capacity agreement. In 2009, Enable Oklahoma entered into a firm transportation service agreement with MEP for 10,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of $2 million.

The Partnership's other future purchase obligations and commitments estimated for the remainder of 2013 and next five years are as follows:

Year ended December 31 (In millions)	2013	2014	2015	2016	2017	2018	Total
Other purchase obligations and commitments	$ 3	$11	$ 4	$ 1	$—	$—	$ 19

(b) Legal, Regulatory and Other Matters

Regulatory Matters

MRT Rate Case. MRT, a subsidiary of the Partnership, made a rate filing with the FERC pursuant to Section 4 of the Natural Gas Act, on August 22, 2012 that became effective March 1, 2013, following a five-month suspension, in which it requested an annual cost of service of $104 million (an increase of approximately $47 million above the annual cost of service underlying the current FERC approved maximum rates for MRT's pipeline). On July 30, 2013, MRT filed with the FERC an uncontested Stipulation and Agreement and Offer of Settlement, resolving all issues in the rate case. The settlement specifies few particulars, other than setting an annual overall cost-of-service for MRT of $84 million and increasing the depreciation rates for certain asset classes. In September 2013, the FERC approved the settlement. Although the settlement became effective November 1, 2013, the settlement rates are effective as of March 1, 2013. As a result, MRT will be making refunds to certain of its customers for amounts collected between the requested $104 million cost of service and the $84 million settlement cost of service, which amounts had previously been reserved.

2013 Fuel Filing. On March 1, 2013, Enable Oklahoma submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2013 through March 31, 2014). The deadline for interventions and protests on the filing was March 18, 2013 and no protests were filed. On June 25, 2013, the FERC accepted Enable Oklahoma's proposed zonal fuel percentages.

Other Proceedings

The Partnership is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(12) Income Taxes

The items comprising income tax expense are as follows:

	Nine months ended September 30, 2013	Nine months ended September 30, 2012
	(In millions)	
Provision (Benefit) for Current Income Taxes		
Federal	$ 1	$ 20
State	1	8
Total Provision (Benefit) for Current Income Taxes	2	28
Provision (Benefit) for Deferred Income Taxes, net		
Federal	$(1,039)	124
State	(158)	8
Total Provision (Benefit) for Deferred Income Taxes, net	(1,197)	132
Total Income Tax Expense (Benefit)	$(1,195)	$ 160

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. The Partnership and its subsidiaries are pass-through entities for federal income tax purposes. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the financial statements, (other than Texas state margin taxes). Consequently, the Statement of Combined and Consolidated Statements of Income does not include an income tax provision for income earned on or after May 1, 2013 (other than Texas state margin taxes).

The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Statutory Federal tax rate	35.0 %	35.0%
State income taxes, net of Federal income tax benefit	1.4	2.5
Net Income attributable to noncontrolling interest	(20)	—
Conversion to partnership	(403.9)	—
Other	(1.8)	0.1
Effective income tax rate	(389.3)%	37.6%

As a result of the conversion to a partnership, CenterPoint Energy assumed all outstanding current income tax liabilities and the deferred income tax assets and liabilities were eliminated by recording a provision for income tax benefit equal to $1.24 billion. Therefore, there were no deferred income tax assets and liabilities balances at September 30, 2013. The components of Deferred Income Taxes at December 31, 2012 were as follows:

	December 31, 2012 (In millions)
Deferred tax assets:	
Current:	
Deferred gas costs	$ 29
Other	2
Total current deferred tax assets	31
Non-current:	
Employee benefits	11
Net operating loss carryforwards	8
Regulatory liabilities	—
Other	7
Total non-current deferred tax assets	26
Total deferred tax assets	57
Deferred tax liabilities:	
Non-current:	
Depreciation	1,219
Other	79
Total non-current deferred tax liabilities	1,298
Accumulated deferred income taxes, net	$ 1,241

At September 30, 2013 and December 31, 2012, the Company had no unrecognized tax benefits related to uncertain tax positions. The Company recognizes interest related to unrecognized tax benefits in interest expense and recognizes penalties in other expense.

(13) Reportable Business Segments

The Partnership's determination of reportable business segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting policies excerpt in Partnership's audited 2012 combined financial statements, which explain that some executive benefit costs of Partnership have not been allocated to business segments. The Partnership uses operating income as the measure of profit or loss for its business segments.

The Partnership's assets and operations are organized into two business segments: (i) gathering and processing, which primarily provides natural gas and crude oil gathering, processing and fractionation services for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. Effective May 1, 2013, the intrastate natural gas pipeline operations acquired from Enogex were combined with the interstate pipelines in the transportation and storage segment and the non-rate regulated natural gas gathering, processing and treating operations acquired from Enogex were combined with field services in the gathering and processing segment.

During the integration of the operations acquired from Enogex, the intrastate natural gas pipelines and non-rate regulated natural gas gathering, processing and treating operations have been identified as separate operating segments, which are aggregated with the respective interstate pipelines and field services operations as the respective (1) transportation and storage and (2) gathering and processing reportable segments.

Financial data for business segments and products and services are as follows:

Nine Months Ended September 30, 2013	Transportation and Storage(1)	Gathering and Processing(2)	Eliminations	Total
		(In millions)		
Revenues(3)(4)	$ 784	$ 1,135	$ (254)	$ 1,665
Cost of goods sold excluding depreciation and amortization	406	673	(252)	827
Operation and maintenance	149	155	(2)	302
Depreciation and amortization	68	80	—	148
Impairment	—	12	—	12
Taxes other than income	24	13	—	37
Operating income	$ 137	$ 202	$ —	$ 339
Total assets	$ 5,629	$ 6,832	$ (1,511)	$10,950
Capital expenditures	$ 97	$ 269	$ —	$ 366

Nine Months Ended September 30, 2012	Transportation and Storage(1)	Gathering and Processing(2)	Eliminations	Total
		(In millions)		
Revenues(3)(4)	$ 374	$ 350	$ (38)	$ 686
Cost of goods sold excluding depreciation and amortization	35	76	(36)	75
Operation and maintenance	111	82	(2)	191
Depreciation and amortization	43	35	—	78
Taxes other than income	24	4	—	28
Operating income	$ 161	$ 153	$ —	$ 314
Total assets as of December 31, 2012	$ 4,052	$ 2,439	$ (9)	$ 6,482
Capital expenditures	$ 81	$ 396	$ —	$ 477

(1) Transportation and storage recorded equity income $12 million and $20 million for the nine months ended September 30, 2013 and 2012, respectively, from its interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of equity method affiliates under the Other Income (Expense) caption. Transportation and Storage's investment in SESH was $201 million and $404 million as of September 30, 2013 and December 31, 2012, respectively, and is included in Investments in equity method affiliates. The Partnership reflected a 50% interest in SESH until May 1, 2013 when the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy. See Note 6 for further discussion regarding SESH.

(2) Gathering and processing recorded equity income of zero and $5 million for the nine months ended September 30, 2013 and 2012, respectively, from its 50% interest in a jointly-owned gas processing plant, Waskom. These amounts are included in Equity in earnings of equity method affiliates under the Other Income (Expense) caption. The Partnership consolidated Waskom during the third quarter of 2012. See Note 6 for further discussion regarding Waskom.

(3) Revenues are comprised of gas transportation, storage, gathering and processing revenues.

(4) The Partnership had no external customers accounting for 10% or more of revenues in periods shown.

(14) Subsequent Events

On November 14, 2013, the Partnership distributed $120 million to the unitholders of record as of October 1, 2013.

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ENOGEX LLC

2012 FINANCIAL REPORT

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations that are found throughout this report.

Abbreviation	Definition
401(k) Plan	Qualified defined contribution retirement plan
ArcLight group	Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, collectively
Atoka	Atoka Midstream LLC joint venture
Chesapeake	Chesapeake Energy Marketing, Inc. and Chesapeake Exploration L.L.C.
Code	Internal Revenue Code of 1986
Cordillera	Cordillera Energy Partners III, LLC
EER	Enogex Energy Resources LLC, wholly-owned subsidiary of Enogex (prior to June 30, 2012, the legal name was OGE Energy Resources LLC)
Enogex	Enogex LLC, collectively with its subsidiaries
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex and a majority-owned subsidiary of OGE Holdings
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
MEP	Midcontinent Express Pipeline, LLC
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
OG&E	Oklahoma Gas and Electric Company
OGE Energy	OGE Energy Corp., parent company of OGE Holdings
OGE Holdings	OGE Enogex Holdings, LLC, wholly-owned subsidiary of OGE Energy and parent company of Enogex Holdings
Oxbow	Oxbow Midstream, LLC
Pension Plan	Qualified defined benefit retirement plan
PHMSA	U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration
PRM	Price risk management
Restoration of Retirement Income Plan	Supplemental retirement plan to the Pension Plan

ENOGEX LLC

2012 FINANCIAL REPORT

FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Report are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words “anticipate”, “believe”, “estimate”, “expect”, “intend”, “objective”, “plan”, “possible”, “potential”, “project” and similar expressions. Actual results may vary materially from those expressed in forward-looking statements. Factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, actions of rating agencies and their impact on capital expenditures;
- the ability of Enogex, Enogex Holdings and OGE Energy to access the capital markets and obtain financing on favorable terms as well as inflation rates and monetary fluctuations;
- prices and availability of natural gas and NGLs, each on a stand-alone basis and in relation to each other as well as the processing contract mix between percent-of-liquids, percent-of-proceeds, keep-whole and fixed-fee;
- business conditions in the energy and natural gas midstream industries;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by Enogex;
- unusual weather;
- availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect the energy and natural gas midstream industries;
- environmental laws and regulations that may impact Enogex’s operations;
- changes in accounting standards, rules or guidelines;
- the cost of protecting assets against, or damage due to, terrorism or cyber-attacks and other catastrophic events;
- advances in technology; and
- creditworthiness of suppliers, customers and other contractual parties.

Enogex undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Financial Statements

ENOGEX LLC
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 (In millions)	2012	2011	2010
OPERATING REVENUES	**$1,608.6**	$1,787.1	$1,707.7
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)	**1,120.1**	1,346.6	1,285.1
Gross margin on revenues	**488.5**	440.5	422.6
OPERATING EXPENSES			
Other operation and maintenance	**172.9**	162.5	145.3
Depreciation and amortization	**108.8**	77.6	71.3
Impairment of assets	**0.4**	6.3	1.1
Gain on insurance proceeds	**(7.5)**	(3.0)	—
Taxes other than income	**28.3**	22.0	20.6
Total operating expenses	**302.9**	265.4	238.3
OPERATING INCOME	**185.6**	175.1	184.3
OTHER INCOME (EXPENSE)			
Interest income	**—**	—	0.1
Other income	**1.0**	3.9	0.2
Other expense	**(4.5)**	(1.3)	(0.3)
Net other income (expense)	**(3.5)**	2.6	—
INTEREST EXPENSE			
Interest on long-term debt	**29.1**	21.8	29.0
Other interest charges	**3.5**	1.1	1.4
Interest expense	**32.6**	22.9	30.4
INCOME BEFORE TAXES	**149.5**	154.8	153.9
INCOME TAX EXPENSE (BENEFIT)	**0.2**	0.2	(325.1)
NET INCOME	**149.3**	154.6	479.0
Less: Net income (loss) attributable to noncontrolling interest	**1.5**	(1.3)	2.9
NET INCOME ATTRIBUTABLE TO ENOGEX LLC	**$ 147.8**	$ 155.9	$ 476.1

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 (In millions)	2012	2011	2010(A)
Net income	**$149.3**	$154.6	$479.0
Other comprehensive income (loss), net of tax			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $0.2 in 2010	**2.2**	1.4	0.8
Net gain (loss) arising during the period	**(10.0)**	(12.7)	6.3
Amortization of prior service cost, net of tax of $0.1 in 2010	**(0.1)**	(0.1)	(0.1)
Postretirement plans:			
Amortization of deferred net loss, net of tax of $0.3 in 2010	**1.6**	1.3	0.7
Net loss arising during the period	**(3.0)**	(2.8)	(2.8)
Amortization of deferred net transition obligation	**0.1**	0.2	0.1
Amortization of prior service cost	**(1.2)**	(1.2)	—
Prior service credit arising during the period	**—**	7.0	—
Deferred commodity contracts hedging (gains) losses reclassified in net income, net of tax of $8.5 in 2010	**(5.1)**	40.2	19.9
Deferred commodity contracts hedging gains (losses)	**0.5**	(5.5)	(16.4)
Other comprehensive income (loss), net of tax	**(15.0)**	27.8	8.5
Comprehensive income (loss)	**134.3**	182.4	487.5
Less: Comprehensive income attributable to noncontrolling interest	**1.5**	(1.3)	2.9
Total comprehensive income (loss) attributable to Enogex LLC	**$132.8**	$183.7	$484.6

(A) As of November 1, 2010, Enogex's earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

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ENOGEX LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (In millions)	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 149.3**	$ 154.6	$ 479.0
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**112.6**	78.2	71.3
Impairment of assets	**0.4**	6.3	1.1
Deferred income taxes, net	**—**	—	(352.7)
(Gain) loss on disposition and abandonment of assets	**4.2**	(2.7)	0.3
Gain on insurance proceeds	**(7.5)**	(3.0)	—
Stock-based compensation expense	**1.7**	4.1	—
Price risk management assets	**5.2**	(2.0)	1.0
Price risk management liabilities	**(5.0)**	18.5	8.1
Other assets	**2.0**	(6.5)	(2.7)
Other liabilities	**6.5**	14.7	7.2
Change in certain current assets and liabilities			
Accounts receivable, net	**5.3**	(8.0)	11.8
Accounts receivable—affiliates	**0.6**	3.1	0.2
Natural gas, natural gas liquids, materials and supplies inventories	**6.1**	(0.1)	(7.0)
Gas imbalance assets	**(7.2)**	0.7	0.6
Other current assets	**0.2**	(0.2)	0.5
Accounts payable	**29.7**	15.3	8.0
Income taxes payable—affiliates	**—**	—	76.5
Gas imbalance liabilities	**(4.7)**	3.0	(5.3)
Other current liabilities	**6.6**	(10.9)	22.7
Net Cash Provided from Operating Activities	**306.0**	265.1	320.6
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(427.9)**	(412.1)	(234.2)
Acquisition of gathering assets	**(78.6)**	(200.4)	—
Reimbursement of capital expenditures	**—**	—	3.3
Proceeds from sale of assets	**0.9**	17.5	0.9
Proceeds from insurance	**7.6**	7.4	—
Net Cash Used in Investing Activities	**(498.0)**	(587.6)	(230.0)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**250.0**	—	—
Contributions from parent	**91.2**	285.5	—
Changes in advances with parent	**71.4**	47.3	227.4
Proceeds from line of credit	**—**	150.0	115.0
Distributions to noncontrolling interest partner	**—**	—	(4.0)
Retirement of long-term debt	**—**	—	(289.2)
Purchase of OGE Energy treasury stock	**(5.9)**	—	—
Distributions to parent	**(67.5)**	(133.0)	(49.4)
Repayment of line of credit	**(150.0)**	(25.0)	(90.0)
Net Cash Provided from (Used in) Financing Activities	**189.2**	324.8	(90.2)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(2.8)**	2.3	0.4
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**4.6**	2.3	1.9
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 1.8**	$ 4.6	$ 2.3

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

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ENOGEX LLC
CONSOLIDATED BALANCE SHEETS

December 31 (In millions)	2012	2011
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 1.8**	$ 4.6
Accounts receivable, less reserve of less than $0.1 each	**134.7**	140.1
Accounts receivable—affiliates	**0.7**	1.3
Natural gas and natural gas liquids inventories	**16.5**	23.7
Materials and supplies, at average cost	**4.9**	3.8
Price risk management	**2.6**	5.7
Gas imbalances	**9.0**	1.8
Assets held for sale	**25.5**	—
Other	**3.7**	3.9
Total current assets	**199.4**	184.9
OTHER PROPERTY AND INVESTMENTS, at cost	**1.5**	1.5
PROPERTY, PLANT AND EQUIPMENT		
In service	**2,869.4**	2,386.5
Construction work in progress	**130.7**	160.6
Total property, plant and equipment	**3,000.1**	2,547.1
Less accumulated depreciation	**738.3**	658.0
Net property, plant and equipment	**2,261.8**	1,889.1
DEFERRED CHARGES AND OTHER ASSETS		
Intangible assets, net	**127.4**	137.0
Goodwill	**39.4**	39.4
Price risk management	**—**	2.1
Other	**21.8**	23.3
Total deferred charges and other assets	**188.6**	201.8
TOTAL ASSETS	**$2,651.3**	$2,277.3

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

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ENOGEX LLC
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 (In millions)	2012	2011
LIABILITIES AND MEMBER'S INTEREST		
CURRENT LIABILITIES		
Accounts payable	**$ 200.2**	$ 170.5
Advances from parent	**137.5**	66.2
Customer deposits	**1.8**	1.9
Ad valorem taxes	**12.9**	8.5
Accrued interest	**11.2**	11.0
Accrued compensation due to OGE Holdings	**10.7**	12.2
Price risk management	**0.3**	0.4
Gas imbalances	**5.0**	9.7
Other	**14.0**	10.4
Total current liabilities	**393.6**	290.8
LONG-TERM DEBT	**698.4**	598.1
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations due to OGE Holdings	**79.4**	60.1
Deferred revenues	**37.7**	40.8
Price risk management	**—**	0.1
Other	**5.1**	4.5
Total deferred credits and other liabilities	**122.2**	105.5
Total liabilities	**1,214.2**	994.4
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
MEMBER'S INTEREST		
Member's interest	**1,461.8**	1,295.3
Accumulated other comprehensive loss	**(45.0)**	(30.0)
Total Enogex LLC member's interest	**1,416.8**	1,265.3
Noncontrolling interest	**20.3**	17.6
Total member's interest	**1,437.1**	1,282.9
TOTAL LIABILITIES AND MEMBER'S INTEREST	**$2,651.3**	$2,277.3

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

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ENOGEX LLC
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 (In millions)		2012	2011
MEMBER'S INTEREST			
Member's interest		**$1,461.8**	$1,295.3
Accumulated other comprehensive loss		**(45.0)**	(30.0)
Total Enogex LLC member's interest		**1,416.8**	1,265.3
Noncontrolling interest		**20.3**	17.6
Total member's interest		**1,437.1**	1,282.9
LONG-TERM DEBT			
SERIES	DUE DATE		
6.875%	Senior Notes, Series Due July 15, 2014	**200.0**	200.0
1.72%	Term Loan Agreement, Due August 2, 2015	**250.0**	—
—%	Revolving Credit Agreement Due December 13, 2016	**—**	150.0
6.25%	Senior Notes, Series Due March 15, 2020	**250.0**	250.0
Unamortized discount		**(1.6)**	(1.9)
Total long-term debt		**698.4**	598.1
Total Capitalization		**$2,135.5**	$1,881.0

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX LLC
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S INTEREST

	Member's Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
		(In millions)		
Balance at December 31, 2009	$ 521.7	$ (41.1)	$ 20.0	$ 500.6
Contribution of income taxes to parent	34.4	(25.2)	—	9.2
Comprehensive income (loss)				
Net income	476.1	—	2.9	479.0
Other comprehensive income (loss)	—	8.5	—	8.5
Comprehensive income (loss)	476.1	8.5	2.9	487.5
Distributions to parent	(49.4)	—	—	(49.4)
Distributions to noncontrolling interest partner	—	—	(4.0)	(4.0)
Balance at December 31, 2010	$ 982.8	$ (57.8)	$ 18.9	$ 943.9
Comprehensive income (loss)				
Net income (loss)	155.9	—	(1.3)	154.6
Other comprehensive income (loss)	—	27.8	—	27.8
Comprehensive income (loss)	155.9	27.8	(1.3)	182.4
Contributions from parent	285.5	—	—	285.5
Distributions to parent	(133.0)	—	—	(133.0)
Contribution of OGE Energy stock compensation	4.1	—	—	4.1
Balance at December 31, 2011	$1,295.3	$ (30.0)	$ 17.6	$1,282.9
Comprehensive income (loss)				
Net income	**147.8**	**—**	**1.5**	**149.3**
Other comprehensive income (loss)	**—**	**(15.0)**	**—**	**(15.0)**
Comprehensive income (loss)	**147.8**	**(15.0)**	**1.5**	**134.3**
Contributions from parent	**90.0**	**—**	**—**	**90.0**
Contribution from noncontrolling interest partner	**—**	**—**	**1.2**	**1.2**
Distributions to parent	**(67.5)**	**—**	**—**	**(67.5)**
Contribution of OGE Energy stock compensation	**2.1**	**—**	**—**	**2.1**
Purchase of OGE Energy treasury stock	**(5.9)**	**—**	**—**	**(5.9)**
Balance at December 31, 2012	**$1,461.8**	**$ (45.0)**	**$ 20.3**	**$1,437.1**

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

ENOGEX LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

Enogex is a Delaware single-member limited liability company, which is wholly-owned by Enogex Holdings, a partnership between OGE Energy and the ArcLight group. Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Also, Enogex holds a 50 percent ownership interest in Atoka. Enogex consolidates Atoka in its Consolidated Financial Statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka.

On October 1, 2010, OGE Energy formed Enogex Holdings as a Delaware single-member limited liability company. On October 5, 2010, OGE Energy contributed its equity interest in Enogex to Enogex Holdings.

On October 5, 2010, OGE Energy entered into an investment agreement with the ArcLight group, whereby the ArcLight group contributed $183,150,000 in exchange for a membership interest in Enogex Holdings. As a result of this transaction, the ArcLight group acquired an indirect interest in Enogex and OGE Energy retained an indirect interest in Enogex. The investment agreement provides the ArcLight group the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. The transaction closed on November 1, 2010. As a result of the investment agreement described above and subsequent disproportionate contributions by the ArcLight group, at December 31, 2012, OGE Energy indirectly owns a 79.9 percent membership interest in Enogex Holdings. See Note 2 for a further discussion.

Upon formation of Enogex Holdings, Enogex's earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level. As a result of the conversion of Enogex to a partnership, all deferred income tax assets and liabilities were eliminated by recording an income tax benefit and OGE Energy assumed $34.4 million of outstanding current income tax liabilities of Enogex equal to the September 2010 distribution to OGE Energy. Also, the Consolidated Statements of Income does not include an income tax provision for income earned on or after November 1, 2010 other than Texas state margin taxes.

At December 31, 2012, Enogex had six wholly-owned active subsidiaries, including Enogex Gathering & Processing LLC, EER, Enogex Products LLC, Enogex Gas Gathering LLC, Enogex Atoka LLC and Roger Mills Gas Gathering, LLC.

Principles of Consolidation

The Consolidated Financial Statements include the accounts and operations of Enogex and its subsidiaries. All significant intercompany transactions have been eliminated in consolidation.

Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of Enogex at December 31, 2012 and 2011 and the results of its operations and cash flows for the years ended

December 31, 2012, 2011 and 2010, have been included and are of a normal recurring nature except as otherwise disclosed. Management also has evaluated the impact of subsequent events for inclusion in Enogex's Consolidated Financial Statements occurring after December 31, 2012 through February 27, 2013, the date Enogex's financial statements were available to be issued, and, in the opinion of management, Enogex's Consolidated Financial Statements and Notes contain all necessary adjustments and disclosures resulting from that evaluation.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on Enogex's Consolidated Financial Statements. However, Enogex believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to Enogex that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of Enogex where the most significant judgment is exercised includes the determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets), contingency reserves, asset retirement obligations, fair value and cash flow hedges, the allowance for uncollectible accounts receivable, the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment, amortization methodologies related to intangible assets and impairment assessments of goodwill.

Cash and Cash Equivalents

For purposes of the Consolidated Financial Statements, Enogex considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable

The allowance for uncollectible accounts receivable for Enogex is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was less than $0.1 million at December 31, 2012 and 2011.

Credit risk is the risk of financial loss to Enogex if counterparties fail to perform their contractual obligations. Enogex maintains credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial position (including credit rating, if available), collateral requirements under certain circumstances, the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty and the monitoring of the financial position of existing counterparties on an ongoing basis.

Natural Gas Inventories

Natural gas inventory is held by Enogex, through its transportation and storage business, to provide operational support for its pipeline deliveries and to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. As part of its asset management activity, Enogex injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2012, 2011 and 2010, Enogex recorded write-downs to market value related to natural gas storage inventory of $5.5 million, $4.8 million and $0.3 million, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind depending on contractual terms. Enogex values all imbalances at an average of current market indices applicable to Enogex's operations, not to exceed net realizable value.

Property, Plant and Equipment

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and removal costs are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

Cox City Plant Fire

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. In March 2012, Enogex reached a settlement agreement with its insurers in this matter. As a result of the settlement agreement, Enogex received additional reimbursements of $7.6 million and recognized a gain of $7.5 million on insurance proceeds in 2012.

In a period in which Enogex has an event that results in the recognition of a material gain or loss on an event that is covered by insurance proceeds, Enogex records an impairment loss for the book value of the damaged asset and an offsetting gain for insurance proceeds if recovery of the loss is considered probable. To the extent proceeds from an insurance settlement exceed recognized losses, Enogex records a gain on insurance proceeds in earnings as the receipts of proceeds are determined to be probable.

Enogex's property, plant and equipment and related accumulated depreciation are divided into the following major classes at:

December 31, 2012 (In millions)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
Natural gas transportation and storage assets	$ 988.6	$ 292.7	$ 695.9
Natural gas gathering and processing assets	2,011.5	445.6	1,565.9
Total property, plant and equipment	$ 3,000.1	$ 738.3	$ 2,261.8

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December 31, 2011 (In millions)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
Natural gas transportation and storage assets	$ 967.0	$ 277.0	$ 690.0
Natural gas gathering and processing assets	1,580.1	381.0	1,199.1
Total property, plant and equipment	$ 2,547.1	$ 658.0	$ 1,889.1

The unamortized computer software costs were $3.9 million and $4.4 million at December 31, 2012 and 2011, respectively. In 2012, 2011 and 2010, amortization expense for computer software costs was $3.1 million, $1.0 million and $2.2 million, respectively.

Intangible Assets

The following table below summarizes Enogex's intangible assets and related accumulated amortization at:

	Total Intangible Assets	Accumulated Amortization (In millions)	Net Intangible Assets
December 31, 2012			
Customer Contract / Acreage Dedication	**$ 141.9**	**$ 14.5**	**$ 127.4**
December 31, 2011			
Customer Contract / Acreage Dedication	$ 141.9	$ 4.9	$ 137.0

In 2012, 2011 and 2010, amortization expense for intangible assets was $9.6 million, $2.1 million and $0.6 million, respectively, including amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

The following table summarizes Enogex's expected amortization of intangible assets for each of the next five years.

	2013	2014	2015 (In millions)	2016	2017
Expected amortization of intangible assets	$9.5	$9.5	$9.5	$9.5	$9.1

Depreciation and Amortization

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 15 years for general plant assets. Amortization of intangible assets other than debt costs is computed using the straight-line method over the respective lives of the intangible assets ranging up to 20 years.

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Asset Retirement Obligations

Enogex has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from three months to 50 years. Enogex also has certain asset retirement obligations primarily related to Enogex's processing plants and compression sites that have not been recorded because Enogex cannot determine when these obligations will be incurred. Asset retirement obligations and related expense recognized during 2011 were less than $0.1 million.

The following table summarizes changes to Enogex's asset retirement obligations during the year ended December 31, 2012.

	(In millions)
Balance at January 1	$ —
Liabilities incurred[A]	0.4
Balance at December 31	$ 0.4

(A) Due to certain Enogex compression assets.

Assessing Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill

Enogex assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. In 2011, Enogex recorded an impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 5), related to the Atoka processing plant. Enogex recorded no other material impairments in 2012, 2011 or 2010.

As a result of the gas gathering acquisitions in November 2011, Enogex recorded goodwill of $39.4 million. Enogex assesses its goodwill for impairment at least annually as of October 1 by comparing the fair value of the reporting unit with its book value, including goodwill. Enogex utilizes the income approach (generally accepted valuation approach) to estimate the fair value of the reporting unit, also giving consideration to alternative methods such as the market and cost approaches. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. Enogex performs its goodwill impairment testing at the natural gas gathering and processing segment reporting unit level. Enogex recorded no impairments of goodwill in 2012.

Revenue Recognition

Operating revenues for gathering, processing, transportation and storage services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Operating revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. Enogex's key natural gas producer customers in 2012 included

Chesapeake Energy Marketing Inc., Apache Corporation and Devon Energy Production Company, L.P. In 2012, these customers accounted for 19.6 percent, 17.8 percent and 10.6 percent, respectively, of Enogex's gathering and processing volumes. In 2012, Enogex's top 10 natural gas producer customers accounted for 73.0 percent of Enogex's gathering and processing volumes.

Enogex recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. Enogex depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally, one third party purchases 50 percent of the NGLs delivered to its system, which accounted for $297.3 million (43.3 percent), $285.4 million (38.8 percent) and $279.8 million (46.0 percent), respectively, of Enogex's total NGLs sales for the years ended December 31, 2012, 2011 and 2010.

Enogex records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.4 million received in excess of construction costs were recognized as Deferred Revenues on Enogex's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related firm transportation service agreement under which service commenced in June 2011. Also, in August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's natural gas gathering and processing volumes on the Oklahoma portion of Enogex's system. As a result, Enogex has recorded $7.1 million in Deferred Revenues on Enogex's Consolidated Balance Sheet at December 31, 2012, which are expected to be recognized based on the estimated average fee per MMBtu processed by the end of 2014. Enogex has also recorded $1.5 million in Deferred Revenues on Enogex's Consolidated Balance Sheet at December 31, 2012 in connection with other gathering and processing agreements.

Enogex engages in asset management and hedging activities related to the purchase and sale of natural gas and NGLs. Contracts utilized in these activities generally include purchases and sales for physical delivery, over-the-counter forward swap and options contracts and exchange traded futures and options. Enogex's transactions that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as PRM Assets or Liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement, or against the brokerage deposits in Other Current Assets. The offsetting unrealized gains and losses from changes in the market value of open contracts are included in Operating Revenues in the Consolidated Statements of Income or in Other Comprehensive Income for derivatives designated and qualifying as cash flow hedges. Contracts resulting in delivery of a commodity are included as sales or purchases in the Consolidated Statements of Income as Operating Revenues or Cost of Goods Sold depending on whether the contract relates to the sale or purchase of the commodity.

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by Enogex's gathering and processing business.

Income Taxes

Prior to November 1, 2010, Enogex was a member of an affiliated group that filed consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. Income taxes were generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Effective November 1, 2010, Enogex was converted to a partnership for income tax purposes and is not subject to Federal income taxes and most state income taxes, with the exception of Texas state margin taxes. For Federal and state income tax purposes other than Texas, all income, expenses, gains, losses and tax credits generated flow through to the owners, and accordingly do not result in a provision for income taxes.

Accumulated Other Comprehensive Income (Loss)

The following table summarizes the components of accumulated other comprehensive loss at December 31, 2012 and 2011 attributable to Enogex. At both December 31, 2012 and 2011, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

December 31 (In millions)	2012	2011
Pension Plan and Restoration of Retirement Income Plan:		
Net loss	**$(36.5)**	$(28.7)
Prior service cost	**0.4**	0.5
Postretirement plans:		
Net loss	**(13.7)**	(12.3)
Prior service cost	**4.6**	5.8
Net transition obligation	**—**	(0.1)
Deferred commodity contracts hedging gains	**0.2**	4.8
Total accumulated other comprehensive loss	**$(45.0)**	$(30.0)

The amounts in accumulated other comprehensive loss at December 31, 2012 that are expected to be recognized into earnings in 2013 are as follows:

	(In millions)
Pension Plan and Restoration of Retirement Income Plan:	
Net loss	$ 2.5
Prior service cost	(0.1)
Postretirement plans:	
Net loss	1.6
Prior service cost	(1.2)
Deferred commodity contracts hedging gains	0.2
Total	$ 3.0

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where Enogex has been designated as one of several potentially responsible parties, the amount accrued represents Enogex's estimated share of the cost. Enogex had no accrued environmental liabilities at December 31, 2012 or 2011.

Related Party Transactions

OGE Energy charged operating costs to Enogex of $28.1 million, $27.0 million and $23.0 million in 2012, 2011 and 2010, respectively. OGE Energy charges operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Included in operating costs charged by OGE Energy are $2.4 million, $2.0 million and $2.7 million in 2012, 2011 and 2010, respectively, for payroll taxes and depreciation and amortization expense directly related to Enogex's operations. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, either as overhead based primarily on labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

Enogex has a transportation contract with its affiliate, OG&E, to transport natural gas to OG&E's natural gas-fired generation facilities. In each of 2012, 2011 and 2010, Enogex recorded revenues from OG&E of $34.8 million for transporting gas to OG&E's natural gas-fired generating facilities. In 2012, 2011 and 2010, Enogex recorded revenues from OG&E of $12.9 million, $12.7 million and $12.7 million, respectively, for natural gas storage services. In 2012, 2011 and 2010, Enogex also recorded natural gas sales to OG&E of $20.4 million, $34.7 million and $50.3 million, respectively. In 2012, 2011 and 2010, Enogex recorded an expense from OG&E of $12.4 million, $8.1 million and $6.8 million, respectively, for electricity used at Enogex's compression sites.

On July 1, 2009, OG&E and Enogex entered into hedging transactions to offset natural gas long positions at Enogex with short natural gas exposures at OG&E resulting from the cost of generation associated with a wholesale power sales contract with the Oklahoma Municipal Power Authority. These transactions are for 50,000 MMBtu per month from August 2009 to December 2013 (see Note 7).

In 2012 and 2011, the parent made contributions to Enogex of $90.0 million and $285.5 million, respectively. In 2012, 2011 and 2010, Enogex made distributions to the parent of $67.5 million, $133.0 million and $49.4 million, respectively.

Upon formation of Enogex Holdings, Enogex's earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level. As a result of the conversion of Enogex to a partnership, all deferred income tax assets and liabilities were eliminated by recording an income tax benefit and OGE Energy assumed $34.4 million of outstanding current income tax liabilities of Enogex equal to the September 2010 distribution to OGE Energy. Also, the Consolidated Statements of Income does not include an income tax provision for income earned on or after November 1, 2010 other than Texas state margin taxes.

Omnibus Agreement

On April 1, 2008, Enogex entered into an omnibus agreement with OGE Energy. The omnibus agreement memorializes Enogex's obligation to reimburse OGE Energy for costs incurred on behalf of Enogex and its subsidiaries. Enogex reimburses OGE Energy for: (i) the performance of general and administrative services for Enogex and its subsidiaries, such as legal, accounting, treasury, finance, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, facilities, fleet management and media services and (ii) the payment of certain operating expenses of Enogex and its subsidiaries, including for compensation and benefits of operating personnel. Pursuant to the Enogex Holdings LLC Agreement, the members agreed to negotiate in good faith to replace the omnibus agreement with a new services agreement between Enogex and OGE Energy. Until the renegotiations are complete, OGE Energy continues to provides services and allocate costs to Enogex on a basis consistent with historical practice.

Seconding Agreement

On December 28, 2010, OGE Energy, OGE Holdings and Enogex Holdings entered into a Seconding Agreement whereby all of Enogex's employees were seconded on January 1, 2011 to OGE Holdings. Under the Seconding Agreement, the employees will continue to perform services for Enogex and Enogex will reimburse OGE Holdings for all employment costs, including compensation and pension obligations, paid during the time of the Seconding Agreement.

Accrued Vacation

Enogex accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned, but not taken. As discussed above, all of Enogex's employees were seconded on January 1, 2011 to OGE Holdings. Therefore, Enogex's vacation obligations are payable to OGE Holdings.

Reclassifications

As discussed in Note 14, during the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented to conform to the 2012 presentation.

2. Investment Agreement with ArcLight

On October 5, 2010, OGE Energy entered into an investment agreement with the ArcLight group, whereby the ArcLight group contributed $183,150,000 in exchange for a membership interest in Enogex Holdings. As part of the investment agreement, OGE Energy and the ArcLight group have agreed to indemnify each other for breaches of representations, warranties and covenants contained in the investment agreement, and, in the case of OGE Energy, for certain tax matters related to Enogex, in each case subject to customary thresholds and survival periods.

Pursuant to the Enogex Holdings LLC Agreement, OGE Holdings' and the ArcLight group's rights to designate directors to the Board of Directors of Enogex Holdings will be determined by percentage ownership. OGE Holdings was initially entitled to designate three directors, and the ArcLight group was initially entitled to designate one director. As its ownership position increases, the ArcLight group will be entitled to increasing board representation. The ArcLight group will also be entitled, at various ownership thresholds, to certain special board approval rights with respect to certain significant actions taken by Enogex Holdings, as well as to appoint additional directors for Enogex Holdings.

To the extent Enogex cannot fund its capital expenditures through internal cash flow and use of its line of credit, Enogex will rely on capital contributions from Enogex Holdings, which, in turn, relies on contributions from OGE Energy and the ArcLight group. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings. In 2011, OGE Energy and the ArcLight group made contributions to Enogex Holdings of $70.9 million and $214.6 million, respectively, to fund a portion of Enogex's 2011 capital requirements. Effective October 1, 2012, OGE Energy and the ArcLight group made contributions to Enogex Holdings of $45.0 million each to fund a portion of Enogex's 2012 capital requirements.

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest. As Enogex Holdings' sole investment is in Enogex, it will rely on distributions from Enogex to fund its distribution obligations to its partners.

Under the terms of the Enogex Holdings LLC Agreement, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated core operating area, subject to certain exceptions. In addition, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated area of mutual interest unless (i) in the case of the ArcLight group, the collective ownership interest of the ArcLight group is less than five percent, (ii) the transaction falls within a defined category of passive financial investments, (iii) the proposed transaction has been disapproved by Enogex Holdings or (iv) the fair market value of the assets located in the area of mutual interest constitutes less than 50 percent of the total fair market value of the assets involved in the transaction. A member permitted to pursue a transaction independently pursuant to the foregoing is not required to offer the assets associated with such transaction to Enogex Holdings.

3. Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board issued "Balance Sheet: Disclosures about Offsetting Assets and Liabilities." The new standard requires entities to disclose information about financial instruments and derivative instruments that are either offset on the balance sheet or are subject to a master netting arrangement, including providing both gross information and net information for recognized assets and liabilities, the net amounts presented on an entity's balance sheet and a description of the rights of setoff associated with these assets and liabilities. The new standard is applicable for all entities that have financial instruments and derivative instruments shown using a net presentation on an entity's balance sheet or are subject to a master netting arrangement. On January 31, 2013, the Financial Accounting Standards Board issued an update to this standard clarifying that the scope includes derivatives, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or are subject to a master netting arrangement or similar agreement. The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013 and is required to be applied retrospectively for all periods presented. Enogex adopted this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard in its 2013 Annual Report.

In February 2013, the Financial Accounting Standards Board issued "Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." The new standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, the new standard requires an entity to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items in net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The new standard is applicable for all entities that issue financial statements that are presented in conformity with GAAP and that report items of other comprehensive income. The new standard is effective for interim and annual reporting periods for fiscal years beginning after December 15, 2012 and is required to be applied prospectively. Enogex adopted this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard in its 2013 Annual Report.

4. Gas Gathering and Processing Acquisitions and Divestitures

Western Oklahoma Gathering Acquisition

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011.

The acquisition described above was accounted for as a business combination. The following table summarizes the purchase price allocation for this acquisition.

	(In millions)
Current assets	$ 5.4
Net property, plant and equipment	24.3
Intangible assets	136.3
Goodwill	39.4
Current liabilities assumed	(5.0)
Total	$ 200.4

The goodwill recognized from this acquisition primarily related to the benefits associated with combining the acquired assets with Enogex's existing assets and operations. All of the goodwill is deductible for tax purposes. The transactions have provided Enogex with key new opportunities in the Granite Wash area. The goodwill has been recorded in the natural gas gathering and processing segment. At December 31, 2012 and 2011, there were no changes in the recognized amount of goodwill resulting from this acquisition, as discussed in Note 1.

Intangible assets consist of identifiable customer contracts and relationships. The acquired intangible assets are being amortized on a straight-line basis over the estimated useful life of 15 years. The net amount of intangible assets and related accumulated amortization was $125.7 million and $10.6 million at December 31, 2012 and $134.8 million and $1.5 million at December 31, 2011, respectively.

Granite Wash Gathering Acquisition

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately $78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of $3.5 million for sales taxes on acquired assets, which are included in taxes other than income.

The acquisition described above was accounted for as a business combination. The purchase price is preliminary and has been allocated to property, plant and equipment based on the estimated fair values at the acquisition date using a third-party valuation expert. This allocation may change in subsequent financial statements. Enogex is currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair value of assets becomes available. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

Texas Panhandle Gathering Divestiture

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer’s gathering and processing volumes on the Texas portion of Enogex’s system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex’s system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by Enogex’s Board of Directors in November 2012, therefore these assets were classified as held for sale on Enogex’s Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

Harrah Gathering and Processing Divestiture

On April 1, 2011, Enogex completed the sale of its Harrah processing plant (38 MMcf/d of capacity) and the associated Wellston and Davenport gathering assets. The proceeds from the sale were $15.9 million and Enogex recorded a pre-tax gain in the second quarter of 2011 of $3.7 million in its natural gas gathering and processing segment.

5. Impairment of Assets

Atoka previously operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. As a result, in August 2011, Enogex recorded an impairment loss of $5.0 million in the natural gas gathering and processing segment associated with the cost it had capitalized in connection with the installation of the leased plant as it will not be able to recover the remaining value of the assets through future cash flows. The noncontrolling interest portion of the impairment loss was $2.5 million which was included in Net Income Attributable to Noncontrolling Interests in Enogex’s Consolidated Statement of Income.

6. Fair Value Measurements

The classification of Enogex’s fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Enogex utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. Enogex has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize Enogex's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2012 and 2011 as well as reconcile Enogex's commodity contracts fair value to PRM Assets and Liabilities on Enogex's Consolidated Balance Sheets at December 31, 2012 and 2011. There were no Level 3 investments held at December 31, 2012 or 2011.

December 31, 2012	Commodity Contracts		Gas Imbalances[A]	
	Assets	Liabilities	Assets[B]	Liabilities[C]
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	**$ 5.0**	**$ 5.0**	**$ —**	**$ —**
Significant other observable inputs (Level 2)	**2.6**	**0.5**	**3.1**	**3.8**
Total fair value	**7.6**	**5.5**	**3.1**	**3.8**
Netting adjustments	**(5.0)**	**(5.2)**	**—**	**—**
Total	**$ 2.6**	**$ 0.3**	**$ 3.1**	**$ 3.8**

December 31, 2011	Commodity Contracts		Gas Imbalances[A]	
	Assets	Liabilities	Assets[B]	Liabilities[C]
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 57.1	$ 52.3	$ —	$ —
Significant other observable inputs (Level 2)	8.2	1.2	1.8	7.7
Total fair value	65.3	53.5	1.8	7.7
Netting adjustments	(57.5)	(53.0)	—	—
Total	$ 7.8	$ 0.5	$ 1.8	$ 7.7

(A) Enogex uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $5.9 million at December 31, 2012 with no comparable item at December 31, 2011, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $1.2 million and $2.0 million at December 31, 2012 and 2011, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes Enogex's assets that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during 2011. There were no Level 3 investments held at December 31, 2012 or 2011.

	Commodity Contracts Assets
	2011
	(In millions)
Balance at January 1	$ 13.3
Included Total gains or losses included in other comprehensive income	(5.4)
Settlements	(7.9)
Balance at December 31	$ —

The following table summarizes the fair value and carrying amount of Enogex's financial instruments, including derivative contracts related to Enogex's PRM activities, at:

December 31 (In millions)	2012 Carrying Amount	2012 Fair Value	2011 Carrying Amount	2011 Fair Value
PRM Assets				
Energy Derivative Contracts	**$ 2.6**	**$ 2.6**	$ 7.8	$ 7.8
PRM Liabilities				
Energy Derivative Contracts	**$ 0.3**	**$ 0.3**	$ 0.5	$ 0.5
Long-Term Debt				
Senior Notes	**$ 448.4**	**$493.4**	$ 448.1	$497.9
Revolving Credit Agreement	**—**	**—**	150.0	150.0
Term Loan	**250.0**	**250.0**	—	—

The carrying value of the financial instruments included in the Consolidated Balance Sheets approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of Enogex's energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of Enogex's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

7. Derivative Instruments and Hedging Activities

Enogex is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivatives instruments is commodity price risk. Enogex is also exposed to credit risk in its business operations.

Commodity Price Risk

Enogex has used forward physical contracts, commodity price swap contracts and commodity price option features to manage Enogex's commodity price risk exposures in the past. Commodity derivative instruments used by Enogex are as follows:

- NGLs put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing operations and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage Enogex's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by Enogex's gathering and processing business.

Enogex recognizes its non-exchange traded derivative instruments as PRM Assets or Liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets.

Credit Risk

Enogex is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe Enogex money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, Enogex may be forced to enter into alternative arrangements. In that event, Enogex's financial results could be adversely affected and Enogex could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income (Loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. Enogex measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

Enogex designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). Enogex also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Enogex's cash flow hedges at December 31, 2012 mature by the end of the first quarter of 2013.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. Enogex includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At December 31, 2012 and 2011, Enogex had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in Enogex's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

At December 31, 2012 and 2011, Enogex had the following derivative instruments that were designated as cash flow hedges.

	Gross Notional Volume(A)	
	2012	2011
	(In millions)	
Enogex hedges		
Natural gas sales	3.7	3.2

(A) Natural gas in MMBtu.

At December 31, 2012, Enogex had the following derivative instruments that were not designated as hedging instruments.

	Gross Notional Volume(A)	
	Purchases	Sales
	(In millions)	
Natural gas(B)		
Physical(C)(D)	7.0	30.1
Fixed Swaps/Futures	16.2	18.5
Basis Swaps	7.3	6.7

(A) Natural gas in MMBtu.

(B) 95.1 percent of the natural gas contracts have durations of one year or less, 2.9 percent have durations of more than one year and less than two years and 2.0 percent have durations of more than two years.

(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.

(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

At December 31, 2011, Enogex had the following derivative instruments that were not designated as hedging instruments.

	Gross Notional Volume(A)	
	Purchases	Sales
	(In millions)	
Natural gas(B)		
Physical(C)(D)	14.3	51.8
Fixed Swaps/Futures	57.9	58.2
Options	17.6	12.8
Basis Swaps	8.2	7.5

(A) Natural gas in MMBtu.

(B) 88.0 percent of the natural gas contracts have durations of one year or less, 5.5 percent have durations of more than one year and less than two years and 6.5 percent have durations of more than two years.

(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.

(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in Enogex's Consolidated Balance Sheet at December 31, 2012 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets (In millions)	Fair Value Liabilities (In millions)
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	**$ —**	**$ 0.5**
Total		**$ —**	**$ 0.5**
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	**$ 2.2**	**$ —**
	Other Current Assets	**5.0**	**4.7**
Physical Purchases/Sales	Current PRM	**0.4**	**0.3**
Total		**$ 7.6**	**$ 5.0**
Total Gross Derivatives(A)		**$ 7.6**	**$ 5.5**

(A) See Note 6 for a reconciliation of Enogex's total derivatives fair value to Enogex's Consolidated Balance Sheet at December 31, 2012.

The fair value of the derivative instruments that are presented in Enogex's Consolidated Balance Sheet at December 31, 2011 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets (In millions)	Fair Value Liabilities (In millions)
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	$ 5.2	$ 0.3
Total		$ 5.2	$ 0.3
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$ 4.4	$ —
	Other Current Assets	49.9	49.9
Physical Purchases/Sales	Current PRM	3.1	0.4
	Non-Current PRM	0.3	0.1
Financial Options	Other Current Assets	2.4	2.8
Total		$60.1	$ 53.2
Total Gross Derivatives(A)		$65.3	$ 53.5

(A) See Note 6 for a reconciliation of Enogex's total derivatives fair value to Enogex's Consolidated Balance Sheet at December 31, 2011.

Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on Enogex's Consolidated Statement of Income in 2012.

Derivatives in Cash Flow Hedging Relationships

	Amount Recognized in Other Comprehensive Income(A)	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
		(In millions)	
Natural Gas Financial Futures/Swaps	**$ 0.5**	**$ 5.2**	**$ —**
Total	**$ 0.5**	**$ 5.2**	**$ —**

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income (Loss) at December 31, 2012 that is expected to be reclassified into income within the next 12 months is a gain of $0.2 million.

Derivatives Not Designated as Hedging Instruments

	Amount Recognized in Income
	(In millions)
Natural Gas Physical Purchases/Sales	**$ (11.7)**
Natural Gas Financial Futures/Swaps	**0.5**
Total	**$ (11.2)**

The following tables present the effect of derivative instruments on Enogex's Consolidated Statement of Income in 2011.

Derivatives in Cash Flow Hedging Relationships

	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
		(In millions)	
NGLs Financial Options	$ (8.4)	$ (9.8)	$ —
Natural Gas Financial Futures/Swaps	2.9	(30.4)	—
Total	$ (5.5)	$ (40.2)	$ —

Derivatives Not Designated as Hedging Instruments

	Amount Recognized in Income
	(In millions)
Natural Gas Physical Purchases/Sales	$ (10.0)
Natural Gas Financial Futures/Swaps	2.4
Total	$ (7.6)

The following tables present the effect of derivative instruments on Enogex's Consolidated Statement of Income in 2010.

Derivatives in Cash Flow Hedging Relationships

	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
		(In millions)	
NGLs Financial Options	$ (9.7)	$ 1.2	$ —
NGLs Financial Futures/Swaps	1.7	(3.7)	—
Natural Gas Financial Futures/Swaps	(14.9)	(25.9)	0.2
Total	$ (22.9)	$ (28.4)	$ 0.2

Derivatives Not Designated as Hedging Instruments

	Amount Recognized in Income
	(In millions)
Natural Gas Physical Purchases/Sales	$ (11.7)
Natural Gas Financial Futures/Swaps	4.0
Total	$ (7.7)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income (Loss) into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2012, 2011 and 2010, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2012, 2011 and 2010, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower Enogex's senior unsecured debt rating to a below investment grade rating, at December 31, 2012, Enogex would have been required to post $0.2 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2012. In addition, Enogex could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

8. Stock-Based Compensation

In 2008, OGE Energy adopted, and its shareowners approved, the 2008 Stock Incentive Plan. Under the 2008 Stock Incentive Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of OGE Energy and its subsidiaries. OGE Energy has authorized the issuance of up to 2,750,000 shares under the 2008 Stock Incentive Plan.

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The following table summarizes Enogex's compensation expense for the years ended December 31, 2012 and 2011 and Enogex's pre-tax compensation expense and related income tax benefit for the year ended December 31, 2010 related to performance units and restricted stock for Enogex employees.

Year ended December 31 (In millions)	2012	2011	2010
Performance units			
Total shareholder return	**$2.3**	$2.1	$1.6
Earnings per share	**1.1**	1.4	0.6
Total performance units	**3.4**	3.5	2.2
Restricted stock	**0.5**	0.6	0.6
Total compensation expense	**$3.9**	$4.1	$2.8
Income tax benefit(A)	**$ —**	$ —	$0.9

(A) As of November 1, 2010, Enogex's earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

OGE Energy has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2012, Enogex purchased 117,368 shares of OGE Energy's treasury stock to satisfy the payout of earned performance units and restricted stock grants. Enogex records treasury stock purchases from OGE Energy at cost. Purchased treasury stock is included in Member's Interest in Enogex's Consolidated Balance Sheet. In 2012, 2011 and 2010, there were 12,969 shares, 74,447 shares and 18,559 shares, respectively, of new common stock issued to Enogex's employees pursuant to OGE Energy's stock incentive plans related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2012, there were 5,199 shares of restricted stock returned to OGE Energy to satisfy tax liabilities.

Performance Units

Under the 2008 Stock Incentive Plan, OGE Energy has issued performance units which represent the value of one share of OGE Energy's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the 2008 Stock Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with OGE Energy or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return are contingently awarded and will be payable in shares of OGE Energy's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle (i.e., three-year cliff vesting period) is dependent on OGE Energy's total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of OGE Energy's common stock based on OGE Energy's earnings per share growth over a three-year award cycle (i.e., three-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of OGE Energy's Board of Directors. All of these performance units are classified as equity in OGE Energy's Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires approval of the Compensation Committee of OGE Energy's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

Performance Units—Total Shareholder Return

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of OGE Energy's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to OGE Energy's performance units based on total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2012	2011	2010
Number of units granted to Enogex employees	**46,944**	59,914	47,355
Fair value of units granted	**$ 51.82**	$ 46.09	$ 39.43
Expected dividend yield	**3.0%**	3.2%	3.9%
Expected price volatility	**22.0%**	33.0%	34.0%
Risk-free interest rate	**0.38%**	1.40%	1.42%
Expected life of units (in years)	**2.87**	2.87	2.87

Performance Units—Earnings Per Share

The fair value of the performance units based on earnings per share is based on grant date fair value which is equivalent to the price of one share of OGE Energy's common stock on the date of grant. The fair value of performance units based on earnings per share varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. OGE Energy reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to OGE Energy's performance units based on earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

	2011	2010
Number of units granted to Enogex employees	19,971	15,784
Fair value of units granted	$ 41.61	$ 32.44

In 2012, the performance unit grant for Enogex employees that was previously based on earnings per share was changed to a cash payment that entitles Enogex employees to receive from 0 percent to 200 percent of the performance units granted based on the growth in Enogex's EBITDA over a three-year award cycle (i.e., three-year cliff vesting period) compared to a growth target set by the Compensation Committee of OGE Energy's Board of Directors.

Restricted Stock

Under the 2008 Stock Incentive Plan and beginning in 2008, OGE Energy issued restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to OGE Energy or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted stock was based on the closing market price of OGE Energy's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a three-year vesting period. Also, Enogex treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the restricted stock is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to OGE Energy's restricted stock. The number of shares of restricted stock granted related to Enogex's employees and the grant date fair value are shown in the following table.

	2012	2011	2010
Shares of restricted stock granted to Enogex employees	**2,891**	14,526	24,615
Fair value of restricted stock granted	**$51.73**	$ 49.27	$ 40.43

A summary of the activity for OGE Energy's performance units and restricted stock applicable to Enogex's employees at December 31, 2012 and changes in 2012 are shown in the following table.

	Performance Units					
	Total Shareholder Return		Earnings Per Share		Restricted Stock	
	Number of Units	Aggregate Intrinsic Value	Number of Units	Aggregate Intrinsic Value	Number of Shares	Aggregate Intrinsic Value
	(Dollars in millions)					
Units/Shares Outstanding at 12/31/11	185,266		61,755		32,268	
Granted[(A)]	46,944		—		2,891	
Converted[(B)]	(70,544)	$ 7.4	(23,515)	$ 2.5	N/A	
Vested	N/A		N/A		(13,928)	$ 0.7
Forfeited	(19,551)		(5,139)		(1,876)	
Units/Shares Outstanding at 12/31/12	142,115	$ 12.1	33,101	$ 3.7	19,355	$ 1.1
Units/Shares Fully Vested at 12/31/12	44,232	$ 5.0	14,743	$ 1.7		

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

(B) These amounts represent performance units that vested at December 31, 2011 which were settled in February 2012.

A summary of the activity for OGE Energy's non-vested performance units and restricted stock applicable to Enogex's employees at December 31, 2012 and changes in 2012 are shown in the following table.

	Performance Units					
	Total Shareholder Return		Earnings Per Share		Restricted Stock	
	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/Shares Non-Vested at 12/31/11	114,722	$ 43.08	38,240	$ 37.47	32,268	$ 43.99
Granted	46,944[(A)]	$ 51.82	—	$ —	2,891	$ 51.73
Vested	(44,232)	$ 39.43	(14,743)	$ 32.44	(13,928)	$ 42.50
Forfeited	(19,551)	$ 44.71	(5,139)	$ 37.08	(1,876)	$ 43.82
Units/Shares Non-Vested at 12/31/12	97,883	$ 48.60	18,358	$ 41.61	19,355	$ 46.24
Units/Shares Expected to Vest	88,126		16,860		19,355	

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

Fair Value of Vested Performance Units and Restricted Stock

A summary of Enogex's fair value for its vested performance units and restricted stock is shown in the following table.

Year ended December 31 (In millions)	2012	2011	2010
Performance units			
Total shareholder return	**$1.7**	$1.8	$1.2
Earnings per share	**1.0**	0.9	0.4
Restricted stock	**0.6**	0.5	0.1

Unrecognized Compensation Cost

A summary of Enogex's unrecognized compensation cost for its non-vested performance units and restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

December 31, 2012	Unrecognized Compensation Cost (in millions)	Weighted Average to be Recognized (in years)
Performance units		
Total shareholder return	$ 2.1	1.64
Earnings per share	0.9	1.14
Total performance units	3.0	
Restricted stock	0.3	1.74
Total	$ 3.3	

Stock Options

OGE Energy last issued stock options in 2004 and as of December 31, 2006, all stock options were fully vested and expensed. All stock options have a contractual life of 10 years. A summary of the activity for OGE Energy's stock options applicable to Enogex's employees at December 31, 2012 and changes during 2012 are shown in the following table.

	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
		(Dollars in millions)		
Options Outstanding at 12/31/11	4,200	$ 23.57		
Exercised	(2,600)	$ 23.57	$ 0.1	
Options Outstanding at 12/31/12	1,600	$ 23.57	$ 0.1	1.06 years
Options Fully Vested and Exercisable at 12/31/12	1,600	$ 23.57	$ 0.1	1.06 years

A summary of the activity for Enogex's exercised stock options in 2012, 2011 and 2010 are shown in the following table.

Year ended December 31 (In millions)	2012	2011	2010
Intrinsic value(A)	**$0.1**	$0.2	$—

(A) The difference between the market value on the date of exercise and the option exercise price.

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9. Supplemental Cash Flow Information

During 2012, 2011 and 2010, there were no investing or financing activities for Enogex that affected recognized assets and liabilities which did not result in cash receipts or payments. The following table discloses information about cash flow activities that include cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

Year ended December 31 (In millions)	2012	2011	2010
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized)(A)	**$31.0**	$24.2	$ 38.1
Income taxes (net of income tax refunds)(B)	**0.2**	0.2	(32.4)

(A) Net of interest capitalized of $4.5 million, $8.7 million and $2.5 million in 2012, 2011 and 2010, respectively.

(B) As of November 1, 2010, Enogex's earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

10. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 (In millions)	2012	2011	2010
Provision for Current Income Taxes			
Federal	**$ —**	$ —	$ 27.0
State	**0.2**	0.2	0.6
Total Provision for Current Income Taxes	**0.2**	0.2	27.6
Benefit for Deferred Income Taxes, net			
Federal	**—**	—	(327.8)
State	**—**	—	(24.9)
Total Benefit for Deferred Income Taxes, net	**—**	—	(352.7)
Total Income Tax Expense (Benefit)	**$0.2**	$0.2	$(325.1)

Prior to November 1, 2010, Enogex was a member of an affiliated group that filed consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, Enogex is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2009 or state and local tax examinations by tax authorities for years prior to 2005. Income taxes were generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Enogex earns Oklahoma state tax credits associated with its investments in natural gas processing facilities which further reduce Enogex's effective tax rate.

Effective November 1, 2010, Enogex was converted to a partnership for income tax purposes and is not subject to Federal income taxes and most state income taxes, with the exception of Texas state margin taxes. For Federal and state income tax purposes other than Texas, all income, expenses, gains, losses and tax credits generated flow through to the owners, and accordingly do not result in a provision for income taxes.

The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

Year ended December 31	2012	2011	2010
Statutory Federal tax rate	**—**	—	35.0%
State income taxes, net of Federal income tax benefit	**0.1**	0.1	2.8
Medicare Part D subsidy	**—**	—	1.5
Income attributable to noncontrolling interest	**—**	—	(1.0)
Partnership earnings not subject to income tax	**—**	—	(5.4)
Conversion to partnership	**—**	—	(244.4)
Other	**—**	—	0.3
Effective income tax rate	**0.1%**	0.1%	(211.2)%

At December 31, 2012 and 2011, Enogex had no material unrecognized tax benefits related to uncertain tax positions.

As a result of the conversion to a partnership in 2010, all deferred income tax assets and liabilities were eliminated by recording a provision for income tax benefit of $376.3 million. Therefore, there are no deferred income tax assets and liabilities balances at December 31, 2012 and 2011.

11. Long-Term Debt

A summary of Enogex’s long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2012, Enogex was in compliance with all of its debt agreements.

Enogex has a $400 million revolving credit agreement which expires December 13, 2016. At December 31, 2012, there were no outstanding borrowings under Enogex’s revolving credit agreement.

Maturities of Enogex’s long-term debt during the next five years consist of $200 million and $250 million in years 2014 and 2015, respectively. There are no maturities of Enogex’s long-term debt in years 2013, 2016 or 2017.

Enogex has previously incurred costs related to debt refinancings. Unamortized debt expense is classified as Deferred Charges and Other Assets and the unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

12. Intercompany Agreements

At December 31, 2012 and 2011, there were $137.5 million and $66.2 million, respectively, in outstanding advances from OGE Energy.

Enogex has an intercompany borrowing agreement with OGE Energy whereby Enogex has access to up to $350 million of OGE Energy’s revolving credit amount. This agreement has a termination date of April 1, 2015. At December 31, 2012 and 2011, there were $128.1 million and $52.1 million, respectively, in outstanding intercompany borrowings under this agreement, which are included in the outstanding advances from OGE Energy above.

OGE Energy’s ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with OGE Energy’s credit facility could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of OGE Energy’s and Enogex’s short-term borrowings, but a reduction in OGE Energy's or Enogex's credit rating would not result in any defaults or accelerations. Any future downgrade of OGE Energy or Enogex could also lead to higher long-term borrowing costs and, if below investment grade, would require Enogex to post collateral or letters of credit.

13. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

Enogex's employees participate in OGE Energy's Pension Plan and Restoration of Retirement Income Plan. In October 2009, OGE Energy's Pension Plan and OGE Energy's 401(k) Plan were amended, effective January 1, 2010 to provide eligible employees a choice to select a future retirement benefit combination from OGE Energy's Pension Plan and OGE Energy's 401(k) Plan.

Employees hired or rehired on or after December 1, 2009 do not participate in the Pension Plan but are eligible to participate in the 401(k) Plan where, for each pay period, OGE Energy contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

It is OGE Energy's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by OGE Energy's actuarial consultants. During 2012 and 2011, OGE Energy made contributions to its Pension Plan of $35 million and $50 million, respectively, none of which was Enogex's portion, to help ensure that the Pension Plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2013, OGE Energy expects to contribute up to $35 million to its Pension Plan, none of which is expected to be Enogex's portion. The expected contribution to the Pension Plan during 2013 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

OGE Energy provides a Restoration of Retirement Income Plan to those participants in OGE Energy's Pension Plan whose benefits are subject to certain limitations of the Code. Participants in the Restoration of Retirement Income Plan receive the same benefits that they would have received under OGE Energy's Pension Plan in the absence of limitations imposed by the Federal tax laws. The Restoration of Retirement Income Plan is intended to be an unfunded plan.

The following table presents the status of Enogex's portion of OGE Energy's Pension Plan and Restoration of Retirement Income Plan at December 31, 2012 and 2011. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss in Enogex's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan	
December 31 (In millions)	2012	2011	2012	2011
Benefit obligations	**$(81.8)**	$(68.4)	**$(1.2)**	$(0.9)
Fair value of plan assets	**35.1**	36.0	**—**	—
Funded status at end of year	**$(46.7)**	$(32.4)	**$(1.2)**	$(0.9)

The following table summarizes the benefit payments Enogex expects to pay related to its Pension Plan and Restoration of Retirement Income Plan. These expected benefits are based on the same assumptions used to measure OGE Energy's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

	Projected Benefit Payments
	(In millions)
2013	$ 5.4
2014	7.8
2015	7.5
2016	7.7
2017	7.9
After 2017	40.0

Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to reduce the funded status volatility of the Plan by utilizing liability driven investing. The purpose of liability driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The investment policy follows a glide path approach that shifts a higher portfolio weighting to fixed income as the Plan's funded status increases. The table below sets forth the targeted fixed income and equity allocations at different funded status levels.

Projected Benefit Obligation Funded Status Thresholds	<90%	95%	100%	105%	110%	115%	120%
Fixed income	50%	58%	65%	73%	80%	85%	90%
Equity	50%	42%	35%	27%	20%	15%	10%
Total	100%	100%	100%	100%	100%	100%	100%

Within the portfolio's overall allocation to equities, the funds are allocated according to the guidelines in the table below.

Asset Class	Target Allocation	Minimum	Maximum
Domestic All-Cap/Large Cap Equity	50%	50%	60%
Domestic Mid-Cap Equity	15%	5%	25%
Domestic Small-Cap Equity	15%	5%	25%
International Equity	20%	10%	30%

OGE Energy has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of Enogex's members and OGE Energy's Investment Committee. The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for each investment manager's respective portfolio.

The portfolio is rebalanced on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three percent to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Core Fixed Income	Barclays Capital Aggregate Index
Interest Rate Sensitive Fixed Income	Barclays Capital Aggregate Index
Long Duration Fixed Income	Barclays Long Government/Credit
Equity Index	Standard & Poor’s 500 Index
All-Cap Equity	Russell 3000 Index
	Russell 3000 Value Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital Investment ACWI ex-US

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody’s Investors Services, Standard & Poor’s Ratings Services or Fitch Ratings. The portfolio may invest up to 10 percent of the portfolio’s market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of OGE Energy’s equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap Index, small dividend yield, return on equity at or near the Russell Midcap Index and an earnings per share growth rate at or near the Russell Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and an earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International All Country World ex-US Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-US Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the United States. All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

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For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. Options or financial futures may not be purchased unless prior approval of OGE Energy's Investment Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of OGE Energy's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Plan Investments

The following tables summarize Enogex's portion of OGE Energy's Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2012 and 2011. There were no Level 3 investments held by the Pension Plan at December 31, 2012 and 2011.

	December 31, 2012	Level 1	Level 2
		(In millions)	
Common stocks			
U.S. common stocks	$ 232.2	$232.2	$ —
Foreign common stocks	39.9	39.9	—
U.S. Government obligations			
U.S. treasury notes and bonds[(A)]	138.6	138.6	—
Mortgage-backed securities	55.8	—	55.8
Bonds, debentures and notes[(B)]			
Corporate fixed income and other securities	98.4	—	98.4
Mortgage-backed securities	13.5	—	13.5
Commingled fund[(C)]	34.9	—	34.9
Common/collective trust[(D)]	25.6	—	25.6
Foreign government bonds	3.9	—	3.9
U.S. municipal bonds	0.8	—	0.8
Interest-bearing cash	0.2	0.2	—
Forward contracts			
Receivable (foreign currency)	0.4	—	0.4
Payable (foreign currency)	(0.4)	—	(0.4)
Total Plan investments	$ 643.8	$410.9	$232.9
Receivable from broker for securities sold	0.8		
Interest and dividends receivable	2.8		
Payable to broker for securities purchased	(21.4)		
Plan investments attributable to affiliates	(590.9)		
Total Plan assets	$ 35.1		

	December 31, 2011	Level 1	Level 2
		(In millions)	
Common stocks			
U.S. common stocks	$ 179.7	$179.7	$ —
Foreign common stocks	59.5	59.5	—
U.S. Government obligations			
U.S. treasury notes and bonds(A)	118.8	118.8	—
Mortgage-backed securities	72.0	—	72.0
Other securities	1.0	—	1.0
Bonds, debentures and notes(B)			
Corporate fixed income and other securities	95.3	—	95.3
Mortgage-backed securities	17.2	—	17.2
Commingled fund(E)	38.5	—	38.5
Common/collective trust(D)	29.6	—	29.6
Foreign government bonds	2.9	—	2.9
Interest-bearing cash	2.1	2.1	—
U.S. municipal bonds	1.7	—	1.7
Preferred stocks (foreign)	0.6	0.6	—
Forward contracts			
Receivable (foreign currency)	4.1	—	4.1
Payable (foreign currency)	(4.1)	—	(4.1)
Total Plan investments	$ 618.9	$360.7	$258.2
Receivable from broker for securities sold	4.8		
Interest and dividends receivable	3.1		
Payable to broker for securities purchased	(37.0)		
Plan investments attributable to affiliates	(553.8)		
Total Plan assets	$ 36.0		

(A) This category represents U.S. treasury notes and bonds with a Moody's Investors Services rating of Aaa and Government Agency Bonds with a Moody's Investors Services rating of A1 or higher.

(B) This category primarily represents U.S. corporate bonds with an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings.

(C) This category represents units of participation in a commingled fund that primarily invested in stocks of international companies and emerging markets.

(D) This category represents units of participation in an investment pool which primarily invests in foreign or domestic bonds, debentures, mortgages, equipment or other trust certificates, notes, obligations issued or guaranteed by the U.S. Government or its agencies, bank certificates of deposit, bankers' acceptances and repurchase agreements, high grade commercial paper and other instruments with money market characteristics with a fixed or variable interest rate. There are no restrictions on redemptions in the common/collective trust.

(E) This category represents units of participation in a commingled fund that primarily invest in stocks and bonds of U.S. companies.

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan at the measurement date. Instruments classified as Level 1 include investments in common and preferred stocks, U.S. treasury notes and bonds, mutual funds and interest-bearing cash.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include corporate fixed income and other securities, mortgage-backed securities, other U.S. Government obligations, commingled fund, a common/collective trust, U.S. municipal bonds, foreign government bonds, a repurchase agreement, money market fund and forward contracts.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the Plan's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Postretirement Benefit Plans

In addition to providing pension benefits, OGE Energy provides certain medical and life insurance benefits for eligible retired members. Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained at least age 55 with 10 or more years of service at the time of retirement are entitled to postretirement medical benefits while employees hired on or after February 1, 2000 are not entitled to postretirement medical benefits. Eligible retirees must contribute such amount as OGE Energy specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. Enogex charges to expense the postretirement benefit costs.

In January 2011, OGE Energy adopted several amendments to its retiree medical plan. Effective January 1, 2012, OGE Energy's contribution to the medical costs for pre-65 aged eligible retirees are fixed at the 2011 level and OGE Energy covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. Also, effective January 1, 2012, Medicare-eligible retirees are no longer eligible to participate in the retiree medical plan. Instead, OGE Energy began providing Medicare-eligible retirees and their Medicare-eligible spouses an annual fixed contribution to OGE Energy's sponsored health reimbursement arrangement. The contribution was determined based on OGE Energy's expected average 2011 premium for medical and drug coverage. Medicare-eligible retirees are able to purchase individual insurance policies supplemental to Medicare through a third-party administrator and use their health reimbursement arrangement funds for reimbursement of medical premiums and other eligible medical expenses. The effect of these plan amendments was reflected in OGE Energy's 2011 Consolidated Balance Sheet as a reduction to the accumulated postretirement benefit obligation of $6.9 million and an increase in other comprehensive income of $6.9 million.

Plan Investments

The following tables summarize Enogex's portion of OGE Energy's postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2012 and 2011. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2012 and 2011.

	December 31, 2012	Level 1	Level 3
		(In millions)	
Group retiree medical insurance contract(A)	$ 53.3	$ —	$ 53.3
Mutual funds investment			
U.S. equity investments	6.0	6.0	—
Money market funds investment	0.3	0.3	—
Total Plan investments	$ 59.6	$ 6.3	$ 53.3
Plan investments attributable to affiliates	(59.6)		
Total Plan assets	$ —		

	December 31, 2011	Level 1	Level 3
		(In millions)	
Group retiree medical insurance contract[A]	$ 54.3	$ —	$54.3
Mutual funds investment			
U.S. equity investments	5.3	5.3	—
Money market funds investment	0.7	0.7	—
Cash	0.7	0.7	—
Total Plan investments	$ 61.0	$ 6.7	$54.3
Plan investments attributable to affiliates	(61.0)		
Total Plan assets	$ —		

(A) This category represents a group retiree medical insurance contract which invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.

The postretirement benefit plans Level 3 investment includes an investment in a group retiree medical insurance contract. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans pro-rata share of the total assets in the contract.

The following table summarizes the postretirement benefit plans investments that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

Year ended December 31 (In millions)	2012
Group retiree medical insurance contract	
Beginning balance	**$54.3**
Net unrealized gains related to instruments held at the reporting date	**5.5**
Interest income	**1.2**
Dividend income	**0.6**
Realized gains	**0.6**
Administrative expenses and charges	**(0.1)**
Claims paid	**(8.8)**
Ending balance	**$53.3**

The following table presents the status of Enogex's portion of OGE Energy's postretirement benefit plans at December 31, 2012 and 2011. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss in Enogex's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

December 31 (In millions)	2012	2011
Benefit obligations	$(31.3)	$(26.5)
Fair value of plan assets	—	—
Funded status at end of year	$(31.3)	$(26.5)

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The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 8.55 percent in 2013 with the rates trending downward to 4.48 percent by 2028. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

Year ended December 31 (In millions)	2012	2011	2010
Effect on aggregate of the service and interest cost components	$ —	$ —	$0.3
Effect on accumulated postretirement benefit obligations	—	—	0.1

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 (In millions)	2012	2011	2010
Effect on aggregate of the service and interest cost components	**$ —**	$ —	$0.3
Effect on accumulated postretirement benefit obligations	**0.1**	0.1	0.2

Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded coverage for prescription drugs. The following table summarizes the gross benefit payments Enogex expects to pay related to its postretirement benefit plans, including prescription drug benefits.

	Gross Projected Postretirement Benefit Payments (In millions)
2013	$ 1.1
2014	1.2
2015	1.3
2016	1.5
2017	1.6
After 2017	9.4

Obligations and Funded Status

The following table presents the status of Enogex's portion of OGE Energy's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans for Enogex's portion of the benefit obligation for OGE Energy's Pension Plan and the Restoration of Retirement Income Plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for OGE Energy's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2012 was $73.4 million and $1.2 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2011 was $60.7 million and $0.8 million, respectively.

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The details of the funded status of the Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans and the amounts included in the Balance Sheets are as follows:

December 31 (In millions)	Pension Plan 2012	Pension Plan 2011	Restoration of Retirement Income Plan 2012	Restoration of Retirement Income Plan 2011	Postretirement Benefit Plans 2012	Postretirement Benefit Plans 2011
Change in Benefit Obligation						
Beginning obligations	**$(68.4)**	$(54.0)	**$ (0.9)**	$ (0.8)	**$(26.5)**	$(29.1)
Service cost	**(4.1)**	(3.8)	**(0.1)**	(0.1)	**(0.8)**	(0.6)
Interest cost	**(3.1)**	(3.2)	**—**	—	**(1.2)**	(1.1)
Plan amendments	**—**	—	**—**	—	**—**	6.9
Participants’ contributions	**—**	—	**—**	—	**(0.2)**	(0.4)
Medicare subsidies received	**—**	—	**—**	—	**—**	(0.1)
Actuarial gains (losses)	**(10.9)**	(10.1)	**(0.2)**	—	**(3.0)**	(2.8)
Benefits paid	**4.7**	2.7	**—**	—	**0.4**	0.7
Ending obligations	**$(81.8)**	$(68.4)	**$ (1.2)**	$ (0.9)	**$(31.3)**	$(26.5)
Change in Plans’ Assets						
Beginning fair value	**$ 36.0**	$ 38.2	**$ —**	$ —	**$ —**	$ —
Actual return on plans’ assets	**3.8**	0.5	**—**	—	**—**	—
Employer contributions	**—**	—	**—**	—	**0.2**	0.2
Participants’ contributions	**—**	—	**—**	—	**0.2**	0.4
Medicare subsidies received	**—**	—	**—**	—	**—**	0.1
Benefits paid	**(4.7)**	(2.7)	**—**	—	**(0.4)**	(0.7)
Ending fair value	**$ 35.1**	$ 36.0	**$ —**	$ —	**$ —**	$ —
Funded status at end of year	**$(46.7)**	$(32.4)	**$ (1.2)**	$ (0.9)	**$(31.3)**	$(26.5)

Net Periodic Benefit Cost

Year ended December 31 (In millions)	Pension Plan 2012	Pension Plan 2011	Pension Plan 2010	Restoration of Retirement Income Plan 2012	Restoration of Retirement Income Plan 2011	Restoration of Retirement Income Plan 2010	Postretirement Benefit Plans 2012	Postretirement Benefit Plans 2011	Postretirement Benefit Plans 2010
Service cost	**$ 4.1**	$ 3.8	$ 3.3	**$ 0.1**	$ 0.1	$0.1	**$ 0.8**	$ 0.6	$0.7
Interest cost	**3.1**	3.2	2.6	**—**	—	—	**1.2**	1.1	1.4
Expected return on plan assets	**(2.7)**	(3.2)	(2.9)	**—**	—	—	**—**	—	—
Amortization of transition obligation	**—**	—	—	**—**	—	—	**0.1**	0.1	0.1
Amortization of net loss	**2.3**	1.4	1.3	**—**	—	—	**1.6**	1.3	0.9
Amortization of unrecognized prior service cost(A)	**(0.1)**	(0.1)	(0.1)	**—**	—	—	**(1.2)**	(1.2)	—
Net periodic benefit cost(B)	**$ 6.7**	$ 5.1	$ 4.2	**$ 0.1**	$ 0.1	$0.1	**$ 2.5**	$ 1.9	$3.1

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) The capitalized portion of the net periodic pension benefit cost was $0.8 million, $0.7 million and $0.6 million at December 31, 2012, 2011 and 2010, respectively. The capitalized portion of the net periodic postretirement benefit cost was $0.7 million, $0.4 million and $0.6 million at December 31, 2012, 2011 and 2010, respectively.

Rate Assumptions

Year ended December 31	Pension Plan and Restoration of Retirement Income Plan 2012	2011	2010	Postretirement Benefit Plans 2012	2011	2010
Discount rate	**3.70%**	4.50%	5.30%	**3.60%**	4.50%	5.30%
Rate of return on plans' assets	**8.00%**	8.00%	8.50%	**N/A**	N/A	N/A
Compensation increases	**4.20%**	4.40%	4.40%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**8.55%**	8.75%	8.99%
Ultimate trend rate	**N/A**	N/A	N/A	**4.48%**	4.48%	5.00%
Ultimate trend year	**N/A**	N/A	N/A	**2028**	2028	2020

N/A—not applicable

The overall expected rate of return on plan assets assumption remained at 8.00 percent in 2011 and 2012 in determining net periodic benefit cost due to recent returns on OGE Energy's long-term investment portfolio. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

Post-Employment Benefit Plan

Disabled employees receiving benefits from OGE Energy's Group Long-Term Disability Plan are entitled to continue participating in OGE Energy's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in OGE Energy's Group Long-Term Disability Plan and their dependents, as defined in OGE Energy's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from OGE Energy's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. Enogex's post-employment benefit obligation was $0.2 million and $0.3 million at December 31, 2012 and 2011, respectively.

401(k) Plan

OGE Energy provides a 401(k) Plan. Each regular full-time employee of OGE Energy or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of OGE Energy or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election.

The 401(k) Plan was amended in October 2009, as discussed previously, whereby participants could select from the options below.

Employment Date	Option 1	Option 2	Option 3
Before February 1, 2000	< 20 years of service—50% Company match up to 6% of compensation	200% Company match up to 5% of compensation	100% Company match up to 6% of compensation
	> 20 years of service—75% Company match up to 6% of compensation	200% Company match up to 5% of compensation	100% Company match up to 6% of compensation
After February 1, 2000 and before December 1, 2009	100% Company match up to 6% of compensation	200% Company match up to 5% of compensation	N/A
After December 1, 2009	200% Company match up to 5% of compensation	N/A	N/A

No OGE Energy contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, OGE Energy's contribution may be directed to any available investment option in the 401(k) Plan. OGE Energy match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their OGE Energy contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by OGE Energy or its affiliates. Enogex contributed $3.6 million, $3.0 million and $2.5 million in 2012, 2011 and 2010, respectively, to the 401(k) Plan.

Deferred Compensation Plan

OGE Energy provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of OGE Energy and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. OGE Energy matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees in the qualified 401(k) Plan discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of OGE Energy or termination of the plan. Deferrals, plus any OGE Energy match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2012, those investment options included an OGE Energy Common Stock fund, whose value was determined based on the stock price of OGE Energy's Common Stock, and various money market, bond and equity funds.

Supplemental Executive Retirement Plan

OGE Energy provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of OGE Energy's Board of Directors who may not otherwise qualify for a sufficient level of benefits under OGE Energy's Pension Plan and Restoration of Retirement Income Plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limitations of the Code.

14. Report of Business Segments

Previously, Enogex's business was divided into three segments as follows: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. As a result of this change, Enogex's business is now divided into two segments for financial reporting purposes as follows: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, Enogex focuses on operating income as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of Enogex's business segments for the years ended December 31, 2012, 2011 and 2010.

2012	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
		(In millions)		
Operating revenues	$ 639.5	$ 1,222.6	$ (253.5)	$1,608.6
Cost of goods sold	504.9	868.7	(253.5)	1,120.1
Gross margin on revenues	134.6	353.9	—	488.5
Other operation and maintenance	49.8	123.1	—	172.9
Depreciation and amortization	24.0	84.8	—	108.8
Impairment of assets	—	0.4	—	0.4
Gain on insurance proceeds	—	(7.5)	—	(7.5)
Taxes other than income	15.7	12.6	—	28.3
Operating income	$ 45.1	$ 140.5	$ —	$ 185.6
Total assets	$ 2,330.8	$ 1,868.6	$ (1,548.1)	$2,651.3
Capital expenditures(A)	$ 32.0	$ 475.4	$ (0.9)	$ 506.5

(A) Includes $78.6 million related to the acquisition of certain gas gathering assets as discussed in Note 4.

2011	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
		(In millions)		
Operating revenues	$ 880.1	$ 1,167.1	$ (260.1)	$1,787.1
Cost of goods sold	736.0	870.7	(260.1)	1,346.6
Gross margin on revenues	144.1	296.4	—	440.5
Other operation and maintenance	50.7	111.8	—	162.5
Depreciation and amortization	22.0	55.6	—	77.6
Impairment of assets	—	6.3	—	6.3
Gain on insurance proceeds	—	(3.0)	—	(3.0)
Taxes other than income	15.0	7.0	—	22.0
Operating income	$ 56.4	$ 118.7	$ —	$ 175.1
Total assets	$ 1,836.9	$ 1,483.8	$ (1,043.4)	$2,277.3
Capital expenditures(A)	$ 41.1	$ 572.0	$ (0.6)	$ 612.5

(A) Includes $200.4 million related to the acquisition of certain gas gathering assets as discussed in Note 4.

2010	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
		(In millions)		
Operating revenues	$ 984.8	$ 1,005.6	$ (282.7)	$1,707.7
Cost of goods sold	834.5	733.3	(282.7)	1,285.1
Gross margin on revenues	150.3	272.3	—	422.6
Other operation and maintenance	53.8	91.5	—	145.3
Depreciation and amortization	21.2	50.1	—	71.3
Impairment of assets	0.7	0.4	—	1.1
Taxes other than income	14.2	6.4	—	20.6
Operating income	$ 60.4	$ 123.9	$ —	$ 184.3
Total assets	$ 1,316.6	$ 973.8	$ (533.1)	$1,757.3
Capital expenditures	$ 72.6	$ 164.0	$ (2.4)	$ 234.2

15. Commitments and Contingencies

Operating Lease Obligations

Enogex has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 (In millions)	2013	2014	2015	2016	2017	After 2017	Total
Noncancellable operating leases	$5.2	$3.7	$3.5	$3.4	$0.7	$ —	$16.5

Payments for operating lease obligations were $7.9 million, $6.2 million and $4.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Noncancellable Operating Leases

Enogex currently occupies 134,219 square feet of office space at its executive offices under a lease that expires March 31, 2017. The lease payments are $11.3 million over the lease term which began April 1, 2012. This lease has rent escalations which increase after five and 10 years if the lease is renewed.

Enogex currently has 17 compression service agreements, of which 10 agreements are on a month-to-month basis, three agreements will expire in 2013, two agreements will expire in 2016 and two agreements will expire in 2017. Enogex also has eight gas treating agreements, of which six agreements are on a month-to-month basis, one agreement will expire in 2013 and one agreement will expire in 2014.

Other Purchase Obligations and Commitments

Enogex's other future purchase obligations and commitments estimated for the next five years are as follows:

	2013	2014	2015	2016	2017	Total
			(In millions)			
Other purchase obligations and commitments						
EER commitments	$11.9	$10.8	$4.7	$0.8	$—	$28.2
Total other purchase obligations and commitments	$11.9	$10.8	$4.7	$0.8	$—	$28.2

EER Commitments

In 2004, EER entered into a firm transportation service agreement with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of $7.4 million. Effective March 1, 2007, EER and Cheyenne Plains amended the firm transportation service agreement to provide for EER to turn back 20,000 decatherms/day of its capacity beginning in January 2008 for the remainder of the term.

In 2006, Enogex entered into a firm capacity agreement with MEP for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP capacity agreement is currently 272 MMcf/d, with the quantity subject to being increased by mutual agreement pursuant to the capacity agreement. In 2009, EER entered into a firm transportation service agreement with MEP for 10,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of $2.1 million.

Environmental Laws and Regulations

The activities of Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Enogex believes that its operations are in substantial compliance with current Federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of Enogex's facilities. Historically, Enogex's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. Enogex believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

Enogex is managing several significant uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. Enogex is unable to predict the financial impact of these matters with certainty at this time. In addition, Enogex is subject to extensive Federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

Pipeline Safety Legislation

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the PHMSA will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law required PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations.

In addition, this law requires PHMSA to issue reports and/or, if appropriate, develop new regulations, addressing a variety of subjects, including: (1) requiring pipeline owners and operators to install excess-flow valves in certain circumstances; (2) requiring pipeline owners and operators to use automatic or remote-controlled shut-off valves in certain circumstances; (3) requiring pipeline owners and operators to test to confirm the strength of previously untested transmission lines located within high consequence areas and operating at a pressure greater than 30 percent of specified minimum yield stress; (4) requiring pipeline owners and operators to notify the National Response Center of an accident or incident at the earliest practicable moment (but not later than one hour) after confirming that an accident or incident has occurred; (5) expanding integrity management requirements beyond high consequence areas; and (6) applying the Federal pipeline safety regulations to onshore gathering lines that are not currently subject to the Federal pipeline safety regulations. This law prescribes various deadlines for PHMSA to act on these issues.

At this time, Enogex is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

Other

In the normal course of business, Enogex is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, Enogex has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in Enogex's Consolidated Financial Statements. At the present time, based on currently available information, except as otherwise stated above and
in Note 16 below, Enogex believes that any reasonably possible losses in excess of accrued amounts arising out

of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on Enogex’s consolidated financial position, results of operations or cash flows.

16. Regulation

Completed Regulatory Matters

2011 Fuel Filing

On February 28, 2011, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2011 through March 31, 2012). Along with the revised fuel percentages, Enogex also requested authority to revise its statement of operating conditions to permanently change the annual filing date to February 28. On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2011 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC’s order approving Enogex’s 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex’s proposed zonal fuel percentages.

2012 Fuel Filing

On February 24, 2012, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the 2012 fuel year (April 1, 2012 through March 31, 2013). On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2012 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC’s order approving Enogex’s 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex’s proposed zonal fuel percentages.

Storage Statement of Operating Conditions Filing

On August 31, 2010, Enogex filed a new statement of operating conditions applicable to storage services with the FERC that replaced Enogex’s existing storage statement of operating conditions effective July 30, 2010. Among other things, the new storage statement of operating conditions updates the general terms and conditions for providing storage services. On December 7, 2012, the FERC issued an order approving Enogex’s revised storage statement of operating conditions, effective August 31, 2010.

FERC Section 311 2011 Rate Case

On January 28, 2011, Enogex submitted a new rate filing to the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex’s filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. On January 10, 2012, Enogex filed a settlement agreement with the FERC. On May 4, 2012, the FERC issued an order approving the settlement agreement in this matter, subject to the submission of a compliance filing to place the settlement rates into effect as of March 1, 2011, which compliance filing was subsequently filed on May 31, 2012. The FERC also requested that Enogex file a revised statement of operating conditions, which was subsequently filed on May 31, 2012. As part of the settlement agreement in this matter, Enogex made refunds of $0.2 million to affected customers on June 15, 2012 and submitted a report to the FERC on July 6, 2012 showing the refund payment calculation. On February 21, 2013, the FERC issued an order approving the refund report.

REPORT OF INDEPENDENT AUDITORS

The Member of Enogex LLC

We have audited the accompanying consolidated financial statements of Enogex LLC, which comprise the consolidated balance sheets and statements of capitalization as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows and changes in member's interest for each of the three years in the period ended December 31, 2012, and the related notes to the consolidated financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting principles used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Enogex LLC at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 27, 2013

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ENOGEX LLC AND SUBSIDIARIES
CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations that are found throughout this report.

Abbreviation	Definition
ArcLight group	Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, collectively
Atoka	Atoka Midstream LLC joint venture
CenterPoint	CenterPoint Energy Resources Corp., wholly-owned subsidiary of CenterPoint Energy, Inc.
EER	Enogex Energy Resources LLC, wholly-owned subsidiary of Enogex LLC (prior to June 30, 2012, the legal name was OGE Energy Resources LLC)
Enogex	Enogex LLC, collectively with its subsidiaries
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex and a majority-owned subsidiary of OGE Holdings, LLC, a wholly-owned subsidiary of OGE Energy
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
Midstream Partnership	Partnership between OGE Energy, the ArcLight group and CenterPoint Energy, Inc. formed to own and operate the midstream businesses of OGE Energy and CenterPoint
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
OG&E	Oklahoma Gas and Electric Company, wholly-owned subsidiary of OGE Energy
OGE Energy	OGE Energy Corp., parent company of OGE Holdings, LLC
Pension Plan	Qualified defined benefit retirement plan
PRM	Price risk management
Restoration of Retirement Income Plan	Supplemental retirement plan to the Pension Plan

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ENOGEX LLC
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(In millions)	
OPERATING REVENUES	**$ 464.3**	$ 429.6
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)	**359.2**	305.3
Gross margin on revenues	**105.1**	124.3
OPERATING EXPENSES		
Other operation and maintenance	**45.2**	42.2
Depreciation and amortization	**27.6**	23.4
Impairment of assets	**—**	0.2
Gain on insurance proceeds	**—**	(7.5)
Taxes other than income	**8.0**	7.3
Total operating expenses	**80.8**	65.6
OPERATING INCOME	**24.3**	58.7
OTHER INCOME (EXPENSE)		
Other income	**10.2**	0.2
Other expense	**(1.2)**	(0.6)
Net other income (expense)	**9.0**	(0.4)
INTEREST EXPENSE		
Interest on long-term debt	**7.2**	6.8
Other interest charges	**0.9**	0.8
Interest expense	**8.1**	7.6
INCOME BEFORE TAXES	**25.2**	50.7
INCOME TAX EXPENSE	**0.1**	0.1
NET INCOME	**25.1**	50.6
Less: Net income attributable to noncontrolling interest	**0.3**	1.1
NET INCOME ATTRIBUTABLE TO ENOGEX LLC	**$ 24.8**	$ 49.5

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

ENOGEX LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(In millions)	
Net income	**$ 25.1**	$ 50.6
Other comprehensive income (loss)		
Pension Plan and Restoration of Retirement Income Plan:		
Amortization of deferred net loss	**0.6**	0.6
Postretirement Benefit Plans:		
Amortization of deferred net loss	**0.4**	0.4
Amortization of prior service cost	**(0.3)**	(0.3)
Deferred commodity contracts hedging gains reclassified in net income	**(0.2)**	(5.2)
Deferred commodity contracts hedging gains (losses)	**—**	0.3
Other comprehensive income (loss)	**0.5**	(4.2)
Comprehensive income (loss)	**25.6**	46.4
Less: Comprehensive income attributable to noncontrolling interest	**0.3**	1.1
Total comprehensive income attributable to Enogex LLC	**$ 25.3**	$ 45.3

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

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ENOGEX LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31,	
	2013	2012
	(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	**$ 25.1**	$ 50.6
Adjustments to reconcile net income to net cash provided from operating activities		
Depreciation and amortization	**28.6**	24.4
Impairment of assets	**—**	0.2
(Gain) loss on disposition and abandonment of assets	**(8.7)**	0.5
Gain on insurance proceeds	**—**	(7.5)
OGE Energy stock-based compensation	**(0.9)**	(0.6)
Price risk management assets	**0.9**	(0.7)
Price risk management liabilities	**—**	(4.9)
Other assets	**(23.5)**	3.1
Other liabilities	**1.2**	0.3
Other liabilities—parent	**2.3**	2.4
Change in certain current assets and liabilities		
Accounts receivable, net	**(6.2)**	16.4
Accounts receivable—affiliates	**(1.4)**	0.3
Natural gas, natural gas liquids, materials and supplies inventories	**7.6**	12.9
Gas imbalance assets	**(3.1)**	(4.0)
Other current assets	**26.1**	(0.8)
Accounts payable	**(2.7)**	(22.8)
Accrued taxes	**(6.5)**	(3.0)
Accrued interest	**(7.4)**	(7.4)
Gas imbalance liabilities	**0.7**	(1.4)
Other current liabilities	**(3.2)**	(3.9)
Net Cash Provided from Operating Activities	**28.9**	54.1
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(128.2)**	(118.5)
Proceeds from sale of assets	**35.4**	0.1
Proceeds from insurance	**—**	6.1
Net Cash Used in Investing Activities	**(92.8)**	(112.3)
CASH FLOWS FROM FINANCING ACTIVITIES		
Changes in advances with parent	**80.4**	91.1
Purchase of OGE Energy treasury stock	**(3.5)**	(5.9)
Distributions to parent	**(12.5)**	(30.0)
Net Cash Provided from Financing Activities	**64.4**	55.2
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**0.5**	(3.0)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**1.8**	4.6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 2.3**	$ 1.6

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

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ENOGEX LLC
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2013 (Unaudited)	December 31, 2012
	(In millions)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 2.3**	$ 1.8
Accounts receivable, less reserve of less than $0.1 each	**140.9**	134.7
Accounts receivable—affiliates	**2.1**	0.7
Natural gas and natural gas liquids inventories	**8.8**	16.5
Materials and supplies, at average cost	**5.0**	4.9
Price risk management	**1.7**	2.6
Gas imbalances	**12.1**	9.0
Assets held for sale	**—**	25.5
Other	**3.1**	3.7
Total current assets	**176.0**	199.4
OTHER PROPERTY AND INVESTMENTS, at cost	**1.5**	1.5
PROPERTY, PLANT AND EQUIPMENT		
In service	**2,939.0**	2,869.4
Construction work in progress	**186.2**	130.7
Total property, plant and equipment	**3,125.2**	3,000.1
Less accumulated depreciation	**763.9**	738.3
Net property, plant and equipment	**2,361.3**	2,261.8
DEFERRED CHARGES AND OTHER ASSETS		
Intangible assets, net	**126.0**	127.4
Goodwill	**39.4**	39.4
Other	**20.1**	21.8
Total deferred charges and other assets	**185.5**	188.6
TOTAL ASSETS	**$ 2,724.3**	$ 2,651.3

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

ENOGEX LLC
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

	March 31, 2013 (Unaudited)	December 31, 2012
	(In millions)	
LIABILITIES AND MEMBER'S INTEREST		
CURRENT LIABILITIES		
Accounts payable	**$ 197.8**	$ 200.2
Advances from parent	**217.9**	137.5
Customer deposits	**1.8**	1.8
Accrued compensation—parent	**9.3**	10.7
Accrued taxes	**6.2**	12.9
Accrued interest	**3.8**	11.2
Price risk management	**0.5**	0.3
Gas imbalances	**5.7**	5.0
Deferred revenues	**4.8**	5.5
Other	**7.3**	8.5
Total current liabilities	**455.1**	393.6
LONG-TERM DEBT	**698.5**	698.4
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations—parent	**81.0**	79.4
Deferred revenues	**38.4**	37.7
Other	**5.4**	5.1
Total deferred credits and other liabilities	**124.8**	122.2
Total liabilities	**1,278.4**	1,214.2
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
MEMBER'S INTEREST		
Member's interest	**1,469.8**	1,461.8
Accumulated other comprehensive loss—parent	**(44.5)**	(45.2)
Accumulated other comprehensive income	**—**	0.2
Total Enogex LLC member's interest	**1,425.3**	1,416.8
Noncontrolling interest	**20.6**	20.3
Total member's interest	**1,445.9**	1,437.1
TOTAL LIABILITIES AND MEMBER'S INTEREST	**$ 2,724.3**	$ 2,651.3

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

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ENOGEX LLC
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S INTEREST
(Unaudited)

	Member's Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Member's Interest
		(In millions)		
Balance at December 31, 2012	**$1,461.8**	**$ (45.0)**	**$ 20.3**	**$1,437.1**
Comprehensive income (loss)				
Net income	**24.8**	**—**	**0.3**	**25.1**
Other comprehensive income (loss)	**—**	**0.5**	**—**	**0.5**
Comprehensive income (loss)	**24.8**	**0.5**	**0.3**	**25.6**
Distributions to parent	**(12.5)**	**—**	**—**	**(12.5)**
OGE Energy stock-based compensation	**(0.8)**	**—**	**—**	**(0.8)**
Purchase of OGE Energy treasury stock	**(3.5)**	**—**	**—**	**(3.5)**
Balance at March 31, 2013	**$1,469.8**	**$ (44.5)**	**$ 20.6**	**$1,445.9**
Balance at December 31, 2011	$1,295.3	$ (30.0)	$ 17.6	$1,282.9
Comprehensive income (loss)				
Net income	49.5	—	1.1	50.6
Other comprehensive income (loss)	—	(4.2)	—	(4.2)
Comprehensive income (loss)	49.5	(4.2)	1.1	46.4
Distributions to parent	(30.0)	—	—	(30.0)
OGE Energy stock-based compensation	0.9	—	—	0.9
Purchase of OGE Energy treasury stock	(7.4)	—	—	(7.4)
Balance at March 31, 2012	$1,308.3	$ (34.2)	$ 18.7	$1,292.8

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

ENOGEX LLC
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

Organization

Enogex is a Delaware single-member limited liability company, which, prior to May 1, 2013, was indirectly owned by OGE Energy and the ArcLight group. Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Also, at March 31, 2013, Enogex held a 50 percent ownership interest in Atoka. At March 31, 2013, Enogex consolidated Atoka in its Condensed Consolidated Financial Statements as Enogex acted as the managing member of Atoka and had control over the operations of Atoka.

On March 14, 2013, OGE Energy entered into a Master Formation Agreement with the ArcLight group and CenterPoint Energy, Inc., pursuant to which OGE Energy, the ArcLight group and CenterPoint Energy, Inc., agreed to form the Midstream Partnership to own and operate the midstream businesses of OGE Energy and CenterPoint. This transaction closed on May 1, 2013. Pursuant to the Master Formation Agreement, OGE Energy and the ArcLight group indirectly contributed Enogex to the Midstream Partnership and CenterPoint Energy, Inc. contributed its midstream natural gas business to the Midstream Partnership. At May 1, 2013, OGE Energy holds 28.5 percent of the limited partners interests, CenterPoint holds 58.3 percent of the limited partner interests and the ArcLight group holds 13.2 percent of the limited partner interests in the Midstream Partnership. The general partner of the Midstream Partnership is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. For additional information regarding the Midstream Partnership, see Note 3.

Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of Enogex at March 31, 2013 and the results of its operations and cash flows for the three months ended March 31, 2013 and 2012, have been included and are of a normal recurring nature except as otherwise disclosed. Management also has evaluated the impact of subsequent events for inclusion in Enogex's Condensed Consolidated Financial Statements occurring after March 31, 2013 through July 15, 2013, the date Enogex's financial statements were available to be issued, and, in the opinion of management, Enogex's Condensed Consolidated Financial Statements and Notes contain all necessary adjustments and disclosures resulting from that evaluation.

Due to seasonal fluctuations and other factors, Enogex's operating results for the three months ended March 31, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013 or for any future period.

Accumulated Other Comprehensive Income (Loss)

In February 2013, the Financial Accounting Standards Board issued "Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." The new standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, the new standard requires an entity to present significant amounts reclassified out of accumulated other comprehensive income by the respective line items in net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period.

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For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. Enogex adopted the new standard effective January 1, 2013 and these disclosures have been included below.

The following table summarizes changes in the components of accumulated other comprehensive loss attributable to Enogex during the three months ended March 31, 2013. At both March 31, 2013 and December 31, 2012, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka. All amounts below are presented net of noncontrolling interest.

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans			
	Net loss	Prior service cost	Net loss	Prior service cost	Deferred commodity contracts hedging gains	Total
Balance at December 31, 2012	$(36.5)	$ 0.4	$ (13.7)	$ 4.6	$ 0.2	$(45.0)
Amounts reclassified from accumulated other comprehensive income (loss)	0.6	—	0.4	(0.3)	(0.2)	0.5
Balance at March 31, 2013	$(35.9)	$ 0.4	$ (13.3)	$ 4.3	$ —	$(44.5)

The following table summarizes significant amounts reclassified out of accumulated other comprehensive loss by the respective line items in net income during the three months ended March 31, 2013.

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss	Affected Line Item in the Statement Where Net Income is Presented
Gains on cash flow hedges		
Commodity contracts	$ 0.2	Cost of goods sold
	$ 0.2	Total
Amortization of defined benefit pension items		
Actuarial gains (losses)	$ (0.6)	(A)
	(0.6)	Total
Amortization of postretirement benefit plan items		
Actuarial gains (losses)	$ (0.4)	(A)
Prior service cost	0.3	(A)
	(0.1)	Total
Total reclassifications for the period	$ (0.5)	Total

(A) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost (see Note 10 for additional information).

Related Party Transactions

OGE Energy charged operating costs to Enogex of $7.9 million and $7.5 million during the three months ended March 31, 2013 and 2012, respectively. OGE Energy charges operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Included in operating costs charged by OGE Energy are $0.6 million and $0.4 million during the three months ended March 31, 2013 and 2012, respectively, for payroll taxes and depreciation and amortization expense directly related to Enogex's operations. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, either as overhead based primarily on labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the Staff of the Oklahoma Corporation Commission. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

Enogex has a transportation contract with its affiliate, OG&E, to transport natural gas to OG&E's natural gas-fired generation facilities. During each of the three months ended March 31, 2013 and 2012, Enogex recorded revenues from OG&E of $8.7 million for transporting gas to OG&E's natural gas-fired generating facilities. During each of the three months ended March 31, 2013 and 2012, Enogex recorded revenues from OG&E of $3.2 million for natural gas storage services. During the three months ended March 31, 2013 and 2012, Enogex also recorded natural gas sales to OG&E of $5.5 million and $3.6 million, respectively. During the three months ended March 31, 2013 and 2012, Enogex recorded an expense from OG&E of $1.8 million and $2.8 million, respectively, for electricity used to power Enogex's electric compression assets.

On July 1, 2009, OG&E and Enogex entered into hedging transactions to offset natural gas long positions at Enogex with short natural gas exposures at OG&E resulting from the cost of generation associated with a wholesale power sales contract with the Oklahoma Municipal Power Authority. These transactions are for 50,000 million British thermal unit per month from August 2009 to December 2013 (see Note 5).

During the three months ended March 31, 2013 and 2012, the parent made no contributions to Enogex. During the three months ended March 31, 2013 and 2012, Enogex made distributions to the parent of $12.5 million and $30.0 million, respectively.

Reclassifications

As discussed in Note 11, during the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented to conform to the 2013 presentation.

2. Gas Gathering Divestiture

Texas Panhandle Gathering Divestiture

As previously reported, on January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed-fee processing agreement replaced the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas was increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. Enogex recognized a pre-tax gain of $9.9 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets which is included in Other Income in the Condensed Consolidated Statements of Income.

3. OGE Energy Midstream Partnership with CenterPoint Energy, Inc.

On March 14, 2013, OGE Energy entered into a Master Formation Agreement with the ArcLight group and CenterPoint Energy, Inc., pursuant to which OGE Energy, the ArcLight group and CenterPoint Energy, Inc., agreed to form the Midstream Partnership to own and operate the midstream businesses of OGE Energy and

CenterPoint that will initially be structured as a private limited partnership. This transaction closed on May 1, 2013.

Pursuant to the Master Formation Agreement, OGE Energy and the ArcLight group indirectly contributed 100 percent of the equity interests in Enogex to the Midstream Partnership. CenterPoint Energy Field Services, LLC, a Delaware limited liability company and wholly owned subsidiary of CenterPoint, was converted into a Delaware limited partnership that became the Midstream Partnership. CenterPoint contributed to the Midstream Partnership its equity interests in each of CenterPoint Energy Gas Transmission Company, LLC, a Delaware limited liability company, CenterPoint Energy—Mississippi River Transmission, LLC, a Delaware limited liability company, and certain of its other midstream subsidiaries and caused its subsidiary CenterPoint Energy Southeastern Pipelines Holding, LLC to contribute a 24.95 percent interest in Southeast Supply Header, LLC, a Delaware limited liability company.

CenterPoint Energy Field Services, LLC provides natural gas gathering and processing services for certain natural gas fields in the Mid-continent region of the United States that interconnect with CenterPoint Energy Gas Transmission Company, LLC and CenterPoint Energy—Mississippi River Transmission, LLC pipelines, as well as other interstate and intrastate pipelines. As of December 31, 2012, CenterPoint Energy Field Services, LLC gathered an average of approximately 2.5 billion cubic feet per day of natural gas. In addition, CenterPoint Energy Field Services, LLC has the capacity available to treat up to 2.5 billion cubic feet per day and process nearly 625 million cubic feet per day of natural gas. CenterPoint Energy Gas Transmission Company, LLC is an interstate pipeline that provides natural gas transportation, storage and pipeline services to customers principally in Arkansas, Louisiana, Oklahoma and Texas and includes the 1.9 billion cubic feet per day pipeline from Carthage, Texas to Perryville, Louisiana, which CenterPoint Energy Gas Transmission Company, LLC operates as a separate line with a fixed fuel rate. CenterPoint Energy—Mississippi River Transmission, LLC is an interstate pipeline that provides natural gas transportation, storage and pipeline services to customers principally in Arkansas, Illinois and Missouri. Southeast Supply Header, LLC owns a 1.0 billion cubic feet per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama.

OGE Energy holds 28.5 percent of the limited partners interests, CenterPoint holds 58.3 percent of the limited partner interests and the ArcLight group holds 13.2 percent of the limited partner interests in the Midstream Partnership.

CenterPoint has certain put rights, and the Midstream Partnership has certain call rights, exercisable with respect to the interest in Southeast Supply Header, LLC retained by CenterPoint, under which CenterPoint would contribute to the Midstream Partnership CenterPoint's retained interest in Southeast Supply Header, LLC at a price equal to the fair market value of such interest at the time the put right or call right is exercised. If CenterPoint were to exercise such put right or the Midstream Partnership were to exercise such call right, CenterPoint's retained interest in Southeast Supply Header, LLC would be contributed to the Midstream Partnership in exchange for consideration consisting of a specified number of limited partnership units and, subject to certain restrictions, a cash payment, payable either from CenterPoint to the Midstream Partnership or from the Midstream Partnership to CenterPoint, in an amount such that the total consideration exchanged is equal in value to the fair market value of the contributed interest in Southeast Supply Header, LLC.

The general partner of the Midstream Partnership is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. CenterPoint and OGE Energy also own a 40 percent and 60 percent interest, respectively, in any incentive distribution rights to be held by the general partner of the Midstream Partnership following an initial public offering of the Midstream Partnership. In addition, for a period of time, the ArcLight group will have board observation rights and approval rights over certain material activities of the Midstream Partnership, including material increases in capital expenditures and certain equity issuances, entering into transactions with related parties and acquiring, pledging or disposing of certain material assets. The general partner of the Midstream Partnership will initially be governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy, Inc. and OGE Energy. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy deconsolidated its interest in Enogex. OGE Energy and CenterPoint will account for their respective interests in the Midstream Partnership under the equity method of accounting.

Immediately prior to closing, on May 1, 2013, the ArcLight group contributed $107.0 million and OGE Energy contributed $9.1 million to Enogex in order to pay down short-term debt. In connection with the formation of the Midstream Partnership, on May 1, 2013, the Midstream Partnership entered into a $1.05 billion three-year senior unsecured Term Loan Facility, the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint. CenterPoint has guaranteed collection of the Midstream Partnership's obligations under the term loan, which guarantee is subordinated to all senior debt of CenterPoint. Effective May 1, 2013, the Midstream Partnership also entered into a $1.4 billion, five-year senior unsecured Revolving Credit Facility in accordance with the terms of the Master Formation Agreement and Enogex's $400 million revolving credit facility was terminated.

At March 31, 2013, Enogex was obligated on approximately $700 million, in the aggregate, in indebtedness under its term loan, its revolving credit agreement and two series of its senior notes maturing in years 2014 and 2020. Certain of the entities contributed to the Midstream Partnership by CenterPoint are obligated on approximately $363 million of indebtedness owed to a wholly owned subsidiary of CenterPoint that is scheduled to mature in 2017.

Subject to the exceptions provided below, pursuant to the terms of an Omnibus Agreement dated as of May 1, 2013 among OGE Energy, the ArcLight group and CenterPoint Energy, Inc., each of OGE Energy and CenterPoint Energy, Inc. will be required to hold or otherwise conduct all of its respective Midstream Operations (as defined below) located within the United States in the Midstream Partnership. This restriction will cease to apply to both OGE Energy and CenterPoint Energy, Inc. as soon as either OGE Energy or CenterPoint Energy, Inc. ceases to hold (i) any interest in the general partner of the Midstream Partnership or (ii) at least 20 percent of the limited partner interests of the Midstream Partnership. "Midstream Operations" generally means, subject to certain exceptions, the gathering, compression, treatment, processing, blending, transportation, storage, isomerization and fractionation of crude oil and natural gas, its associated production water and enhanced recovery materials such as carbon dioxide, and its respective constituents and the following products: methane, NGLs (Y-grade, ethane, propane, normal butane, isobutane and natural gasoline), condensate, and refined products and distillates (gasoline, refined product blendstocks, olefins, naphtha, aviation fuels, diesel, heating oil, kerosene, jet fuels, fuel oil, residual fuel oil, heavy oil, bunker fuel, cokes, and asphalts), to the extent such activities are located within the United States.

In addition, if OGE Energy or CenterPoint Energy, Inc. acquires any assets or equity of any person engaged in Midstream Operations with a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired Midstream Operations that have not been offered to the Midstream Partnership), the acquiring party will be required to offer the Midstream Partnership the opportunity to acquire such assets or equity for such value; provided, that the acquiring party will not be obligated to offer any such assets or equity to the Midstream Partnership if the acquiring party intends to cease using them in Midstream Operations within 12 months. If the Midstream Partnership does not exercise its option, then the acquiring party will be free to retain and operate such Midstream Operations; provided, however, that if the fair market value of such Midstream Operations is greater than 66 2/3 percent of the fair market value of all of the assets being acquired in such transaction, then the acquiring party will be required to dispose of such Midstream Operations within 24 months.

As long as the ArcLight group has board observation rights, the ArcLight group will be prohibited from pursuing any transaction independently from the Midstream Partnership (i) if the ArcLight group's consent is required for the Midstream Partnership to pursue such transaction and (ii) the ArcLight group affirmatively votes not to consent to such transaction.

4. Fair Value Measurements

The classification of Enogex's fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Enogex utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Consolidated Balance Sheets. Enogex has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize Enogex's assets and liabilities that are measured at fair value on a recurring basis at March 31, 2013 and December 31, 2012 as well as reconcile Enogex's commodity contracts fair value to PRM Assets and Liabilities on Enogex's Condensed Consolidated Balance Sheets at March 31, 2013 and December 31, 2012. Enogex adopted the Financial Accounting Standards Board accounting guidance requiring additional disclosures for balance sheet offsetting of assets and liabilities effective January 1, 2013. Enogex posted $0.1 million and $0.2 million of collateral at March 31, 2013 and December 31, 2012, respectively, which has been included within netting adjustments in the table below. Enogex held no collateral at March 31, 2013 or December 31, 2012. Enogex has offset all amounts subject to master netting agreements in Enogex's Condensed Consolidated Balance Sheets at March 31, 2013 and December 31, 2012. Enogex held no Level 1 investments at March 31, 2013 and no Level 3 investments at March 31, 2013 or December 31, 2012.

	March 31, 2013			
	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets (B)	Liabilities (C)
	(In millions)			
Significant other observable inputs (Level 2)	**$ 1.8**	**$ 0.7**	**$ 3.6**	**$ 4.6**
Total fair value	**1.8**	**0.7**	**3.6**	**4.6**
Netting adjustments	**(0.1)**	**(0.2)**	**—**	**—**
Total	**$ 1.7**	**$ 0.5**	**$ 3.6**	**$ 4.6**

	December 31, 2012			
	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets (B)	Liabilities (C)
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 5.0	$ 5.0	$ —	$ —
Significant other observable inputs (Level 2)	2.6	0.5	3.1	3.8
Total fair value	7.6	5.5	3.1	3.8
Netting adjustments	(5.0)	(5.2)	—	—
Total	$ 2.6	$ 0.3	$ 3.1	$ 3.8

(A) Enogex uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $8.5 million and $5.9 million at March 31, 2013 and December 31, 2012, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $1.1 million and $1.2 million at March 31, 2013 and December 31, 2012, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the fair value and carrying amount of Enogex's financial instruments, including derivative contracts related to Enogex's PRM activities, at March 31, 2013 and December 31, 2012.

	March 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
PRM Assets				
Energy Derivative Contracts	**$ 1.7**	**1.7**	$ 2.6	$ 2.6
PRM Liabilities				
Energy Derivative Contracts	**$ 0.5**	**0.5**	$ 0.3	$ 0.3
Long-Term Debt				
Enogex Senior Notes	**448.5**	**492.1**	448.4	493.4
Enogex Term Loan	**250.0**	**250.0**	250.0	250.0

The carrying value of the financial instruments included in the Condensed Consolidated Balance Sheets approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of Enogex's energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of Enogex's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

5. Derivative Instruments and Hedging Activities

Enogex is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. Enogex is also exposed to credit risk in its business operations.

Commodity Price Risk

Enogex has used forward physical contracts, commodity price swap contracts and commodity price option features to manage Enogex's commodity price risk exposures in the past. Commodity derivative instruments used by Enogex are as follows:

- NGLs put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing operations and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage Enogex's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings are recognized in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by Enogex's gathering and processing business.

Enogex recognizes its non-exchange traded derivative instruments as PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Consolidated Balance Sheets.

Credit Risk

Enogex is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe Enogex money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, Enogex may be forced to enter into alternative arrangements. In that event, Enogex's financial results could be adversely affected and Enogex could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income (Loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. Enogex measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

Enogex designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing operations and natural gas transportation and storage operations (operational gas hedges). Enogex also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Enogex had no instruments designated as cash flow hedges at March 31, 2013.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. Enogex includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At March 31, 2013 and December 31, 2012, Enogex had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated as Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in Enogex's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

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Quantitative Disclosures Related to Derivative Instruments

At March 31, 2013, Enogex had the following derivative instruments that were not designated as hedging instruments.

	Gross Notional Volume[A]	
	Purchases	Sales
	(In millions)	
Natural gas[B]		
Physical[C][D]	7.0	72.6
Fixed Swaps/Futures	0.1	1.0
Basis Swaps	5.2	11.6

(A) Natural gas in million British thermal units.

(B) 94.4 percent of the natural gas contracts have durations of one year or less, 4.1 percent have durations of more than one year and less than two years and 1.5 percent have durations of more than two years.

(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.

(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in Enogex's Condensed Consolidated Balance Sheet at March 31, 2013 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets	Fair Value Liabilities
		(In millions)	
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	**$ 1.3**	**$ —**
	Other Current Assets	**0.1**	**0.2**
Physical Purchases/Sales	Current PRM	**0.4**	**0.4**
Total		**$ 1.8**	**$ 0.6**
Total Gross Derivatives[A]		**$ 1.8**	**$ 0.6**

(A) See Note 4 for a reconciliation of Enogex's total derivatives fair value to Enogex's Condensed Consolidated Balance Sheet at March 31, 2013.

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The fair value of the derivative instruments that are presented in Enogex's Condensed Consolidated Balance Sheet at December 31, 2012 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets	Fair Value Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	$ —	$ 0.5
Total		$ —	$ 0.5
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$ 2.2	$ —
	Other Current Assets	5.0	4.7
Physical Purchases/Sales	Current PRM	0.4	0.3
Total		$ 7.6	$ 5.0
Total Gross Derivatives[(A)]		$ 7.6	$ 5.5

(A) See Note 4 for a reconciliation of Enogex's total derivatives fair value to Enogex's Condensed Consolidated Balance Sheet at December 31, 2012.

Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on Enogex's Condensed Consolidated Statement of Income for the three months ended March 31, 2013.

Derivatives in Cash Flow Hedging Relationships

	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
		(In millions)	
Natural Gas Financial Futures/Swaps	**$ —**	**$ 0.2**	**$ —**
Total	**$ —**	**$ 0.2**	**$ —**

Derivatives Not Designated as Hedging Instruments

	Amount Recognized in Income
	(In millions)
Natural Gas Financial Futures/Swaps	**$ (1.1)**
Total	**$ (1.1)**

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The following tables present the effect of derivative instruments on Enogex's Condensed Consolidated Statement of Income for the three months ended March 31, 2012.

Derivatives in Cash Flow Hedging Relationships

	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
		(In millions)	
Natural Gas Financial Futures/Swaps	$ 0.3	$ 5.2	$ —
Total	$ 0.3	$ 5.2	$ —

Derivatives Not Designated as Hedging Instruments

	Amount Recognized in Income
	(In millions)
Natural Gas Physical Purchases/Sales	$ (2.4)
Natural Gas Financial Futures/Swaps	0.4
Total	$ (2.0)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income (Loss) into income (effective portion) and amounts recognized in income (ineffective portion) for the three months ended March 31, 2013 and 2012, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the three months ended March 31, 2013 and 2012, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower Enogex's senior unsecured debt rating to a below investment grade rating, Enogex would have been required to post no cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at March 31, 2013. Enogex could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

6. Stock-Based Compensation

The following table summarizes Enogex's compensation expense during the three months ended March 31, 2013 and 2012 related to Enogex's performance units and restricted stock.

	Three Months Ended March 31, 2013	2012
	(In millions)	
Performance units		
Total shareholder return	**$ 0.6**	0.6
Earnings per share	**0.1**	0.2
Total performance units	**0.7**	0.8
Restricted stock	**0.1**	0.2
Total compensation expense	**$ 0.8**	1.0

OGE Energy has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. During the three months ended March 31, 2013, Enogex purchased 62,632 shares of OGE Energy's treasury stock to satisfy the payouts of earned performance units and restricted stock grants. Enogex records treasury stock purchases from OGE Energy at cost. Purchased treasury stock is included in Member's Interest in Enogex's Condensed Consolidated Balance Sheet. During the three months ended March 31, 2013, there were 16,707 shares of new common stock issued to Enogex's employees pursuant to OGE Energy's stock incentive plans related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. During the three months ended March 31, 2013, there were no shares of restricted stock returned to OGE Energy to satisfy tax liabilities.

The following table summarizes the activity of Enogex's stock-based compensation during the three months ended March 31, 2013.

	Units/Shares	Fair Value
Grants		
Performance units (Total shareholder return)	45,695	$ 51.78
Conversions		
Performance units (Total shareholder return)(A)	44,232	N/A
Performance units (Earnings per share)(A)	14,743	N/A

(A) Performance units were converted based on a payout ratio of 200 percent of the target number of performance units granted in February 2010 and are included in the 16,707 and 62,632 shares of common stock issued during the three months ended March 31, 2013 as discussed above.

7. Income Taxes

Prior to November 1, 2010, Enogex was a member of an affiliated group that filed consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, Enogex is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2009 or state and local tax examinations by tax authorities for years prior to 2005. Income taxes were generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Enogex earns Oklahoma state tax credits associated with its investments in natural gas processing facilities which further reduce Enogex's effective tax rate.

Effective November 1, 2010, Enogex was converted to a partnership for income tax purposes and is not subject to Federal income taxes and most state income taxes, with the exception of Texas state margin taxes. For Federal and state income tax purposes other than Texas, all income, expenses, gains, losses and tax credits generated flow through to the owners, and accordingly do not result in a provision for income taxes.

8. Long-Term Debt

At March 31, 2013, Enogex was in compliance with all of its debt agreements.

Effective May 1, 2013, the Midstream Partnership entered into a $1.4 billion, five-year senior unsecured Revolving Credit Facility in accordance with the terms of the Master Formation Agreement and Enogex's $400 million revolving credit facility was terminated.

9. Intercompany Agreements

At March 31, 2013 and December 31, 2012, there were $217.9 million and $137.5 million, respectively, in outstanding advances from OGE Energy.

Prior to May 1, 2013, Enogex had an intercompany borrowing agreement with OGE Energy whereby Enogex had access to up to $350 million of OGE Energy's revolving credit amount. This agreement was terminated on May 1, 2013 in conjunction with the formation of the Midstream Partnership. At March 31, 2013 and December 31, 2012, there were $204.9 million and $128.1 million, respectively, in outstanding intercompany borrowings under this agreement, which are included in the outstanding advances from OGE Energy above.

10. Retirement Plans and Postretirement Benefit Plans

The details of net periodic benefit cost of Enogex's portion of OGE Energy's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans included in the Condensed Consolidated Financial Statements are as follows:

Net Periodic Benefit Cost

	Pension Plan Three Months Ended March 31,		Postretirement Benefit Plans Three Months Ended March 31,	
	2013	**2012**	**2013**	**2012**
	(In millions)			
Service cost	**$ 1.1**	$ 1.0	**$ 0.2**	$ 0.2
Interest cost	**0.7**	0.8	**0.3**	0.3
Expected return on plan assets	**(0.6)**	(0.7)	**—**	—
Amortization of net loss	**0.6**	0.6	**0.4**	0.4
Amortization of unrecognized prior service cost(A)	**—**	—	**(0.3)**	(0.3)
Net periodic benefit cost	**$ 1.8**	$ 1.7	**$ 0.6**	$ 0.6

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

The capitalized portion of net periodic pension benefit cost was $0.2 million during each of the three months ended March 31, 2013 and 2012. The capitalized portion of net periodic postretirement benefit cost was $0.2 million during the three months ended March 31, 2013 as compared to $0.1 million during the same period in 2012.

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11. Report of Business Segments

Previously, Enogex's business was divided into three segments as follows: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. As a result of this change, Enogex's business is now divided into two segments for financial reporting purposes as follows: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, Enogex focuses on operating income as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of Enogex's business segments during the three months ended March 31, 2013 and 2012.

Three Months Ended March 31, 2013	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
		(In millions)		
Operating revenues	**$ 216.4**	**$ 317.9**	**$ (70.0)**	**$ 464.3**
Cost of goods sold	**182.7**	**246.4**	**(69.9)**	**359.2**
Gross margin on revenues	**33.7**	**71.5**	**(0.1)**	**105.1**
Other operation and maintenance	**10.9**	**34.3**	**—**	**45.2**
Depreciation and amortization	**5.8**	**21.8**	**—**	**27.6**
Taxes other than income	**4.8**	**3.2**	**—**	**8.0**
Operating income (loss)	**$ 12.2**	**$ 12.2**	**$ (0.1)**	**$ 24.3**
Total assets	**$ 2,453.0**	**$ 1,948.9**	**$ (1,677.6)**	**$2,724.3**

Three Months Ended March 31, 2012	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
		(In millions)		
Operating revenues	$ 169.5	$ 304.5	$ (44.4)	$ 429.6
Cost of goods sold	131.8	217.9	(44.4)	305.3
Gross margin on revenues	37.7	86.6	—	124.3
Other operation and maintenance	12.1	30.1	—	42.2
Depreciation and amortization	5.6	17.8	—	23.4
Impairment of assets	—	0.2	—	0.2
Gain on insurance proceeds	—	(7.5)	—	(7.5)
Taxes other than income	4.8	2.5	—	7.3
Operating income (loss)	$ 15.2	$ 43.5	$ —	$ 58.7
Total assets	$ 1,950.3	$ 1,574.1	$ (1,182.6)	$2,341.8

12. Commitments and Contingencies

Except as set forth in Note 13 below, the circumstances set forth in Notes 15 and 16 to Enogex's Consolidated Financial Statements for the year ended December 31, 2012 appropriately represent, in all material respects, the current status of Enogex's material commitments and contingent liabilities.

Other

In the normal course of business, Enogex is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, Enogex has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in Enogex's Condensed Consolidated Financial Statements. At the present time, based on currently available information, except as otherwise stated in Note 13 below and in Notes 15 and 16 of Notes to Consolidated Financial Statements for the year ended December 31, 2012 , Enogex believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on Enogex's consolidated financial position, results of operations or cash flows.

13. Regulation

Except as set forth below, the circumstances set forth in Note 16 to Enogex's Consolidated Financial Statements for the year ended December 31, 2012 appropriately represent, in all material respects, the current status of Enogex's regulatory matters.

Pending Regulatory Matter

2013 Fuel Filing

On March 1, 2013, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2013 through March 31, 2014). The deadline for interventions and protests on the filing was March 18, 2013 and no protests were filed. On June 25, 2013, the FERC accepted Enogex's proposed zonal fuel percentages.

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APPENDIX A

SECOND AMENDED AND RESTATED AGREEMENT
OF LIMITED PARTNERSHIP OF ENABLE MIDSTREAM PARTNERS, LP

[*To be filed by amendment.*]

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APPENDIX B

GLOSSARY

2011 Pipeline Safety Act. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

Adjusted EBITDA. Net income from continuing operations before interest expense, income tax expense, depreciation and amortization expense and certain other items management believes affect the comparability of operating results.

APSA. Accountable Pipeline Safety and Partnership Act of 1996.

ArcLight. ArcLight Capital Partners, LLC, a Delaware limited liability company, its affiliated entities ArcLight Energy Partners Fund V, L.P., ArcLight Energy Partners Fund IV, L.P., and Bronco Midstream Partners, L.P., and their respective general partners and subsidiaries.

Barrel. One barrel of petroleum products equals 42 U.S. gallons.

Bbl. Barrel.

Bbl/d. Barrels per day.

Bcf. Billion cubic feet.

Bcf/d. Billion cubic feet per day.

Btu. British thermal unit. When used in terms of volume, Btu refers to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.

CAA. Clean Air Act, as amended.

CEFS. CenterPoint Energy Field Services, LLC, a Delaware limited liability company, that was converted into a Delaware limited partnership that became the partnership.

CenterPoint Energy. CenterPoint Energy, Inc., a Texas corporation, and its subsidiaries, other than Enable Midstream Partners, LP.

Central receipt point. A single receipt point into a gathering line where a producer aggregates the volumes from more than one well and delivers them into the gathering system at a single meter site.

CERCLA. Comprehensive Environmental Response, Compensation and Liability Act of 1980.

CFTC. Commodity Futures Trading Commission.

CO2e. Carbon dioxide equivalent.

COBRA. Consolidated Omnibus Budget Reconciliation Act of 1985.

Code. The Internal Revenue Code of 1986, as amended.

Condensate. A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Delaware Act. Delaware Revised Uniform Limited Partnership Act.

DHS. Department of Homeland Security.

Dodd-Frank Act. Dodd-Frank Wall Street Reform and Consumer Protection Act.

DOT. Department of Transportation.

EGT. Enable Gas Transmission System pipeline, a 5,954-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas.

EIA. Energy Information Administration.

Enable GP. Enable GP, LLC, a Delaware limited liability company and the general partner of Enable Midstream Partners, LP.

Enogex. Enogex LLC, a Delaware limited liability company.

ESA. Endangered Species Act.

EPA. Environmental Protection Agency.

EPAct of 2005. Energy Policy Act of 2005.

ERISA. Employee Retirement Income Security Act of 1974.

Exchange Act. Securities Exchange Act of 1934, as amended.

FERC. Federal Energy Regulatory Commission.

FINRA. Financial Industry Regulatory Authority.

Fractionation. The separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale.

GAAP. Generally accepted accounting principles in the United States.

Gas imbalance. The difference between the actual amounts of natural gas delivered from or received by a pipeline.

General partner. Enable GP, LLC, a Delaware limited liability company, the general partner of Enable Midstream Partners, LP.

GHG. Greenhouse gas.

Gross margin. Total revenues minus cost of goods sold, excluding depreciation and amortization.

HCA. High-consequence area.

HLPSA. Hazardous Liquid Pipeline Safety Act of 1979.

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Hinshaw pipeline. A pipeline is exempt from FERC's NGA regulation if its operations are within a single state, if any gas received from interstate sources is received within the state and if its service is regulated by the state commission.

ICA. Interstate Commerce Act.

IRS. Internal Revenue Service.

LDC. Local distribution companies involved in the delivery of natural gas to consumers within a specific geographic area.

Lean gas. Natural gas that is primarily methane without NGLs.

LIBOR. London Interbank Offered Rate.

LNG. Liquefied natural gas.

MAOP. Maximum allowable operating pressure for gas pipelines.

MBbl/d. Thousand barrels per day.

MMcf. Million cubic feet of natural gas.

MMBtu. Million British thermal units.

MMcf/d. Million cubic feet per day.

MOP. Maximum operating pressure for hazardous liquid pipelines.

MRT. Mississippi River Transmission System pipeline, a 1,560-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois.

NEPA. National Environmental Policy Act.

NGA. Natural Gas Act of 1938.

NGPA. Natural Gas Policy Act of 1978.

NGPSA. Natural Gas Pipeline Safety Act of 1968.

NGLs. Natural gas liquids, which are the hydrocarbon liquids contained within natural gas including condensate.

NYSE. New York Stock Exchange.

OGE Energy. OGE Energy Corp., an Oklahoma corporation, and its subsidiaries, other than Enable Midstream Partners, LP.

OPA. Oil Pollution Act.

OSHA. Occupational Safety and Health Act of 1970.

partnership. Enable Midstream Partners, LP.

PDO. Petition for a Declaratory Order. Petition filed with FERC to seek regulatory assurances for key terms of service offered during an open season.

PHMSA. Pipeline and Hazardous Materials Safety Administration.

PIPES Act. Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006.

Prospectus Directive. Directive 2003/71/EC and amendments thereto.

PSA. Pipeline Safety Act of 1992.

PSIA. Pipeline Safety Improvement Act of 2002.

RCRA. Resource Conservation and Recovery Act of 1976.

REIT. Real Estate Investment Trust.

Residue gas. The pipeline quality natural gas remaining after natural gas is processed.

RICE MACT. Reciprocating internal combustion engines maximum achievable control technology.

Rich gas. Natural gas containing higher concentrations of NGLs that is usually produced in association with crude oil.

SCOOP. South Central Oklahoma Oil Province.

SDWA. Safe Drinking Water Act.

SEC. Securities and Exchange Commission.

Securities Act. Securities Act of 1933, as amended.

SESH. Southeast Supply Header System, LLC.

Sponsors. CenterPoint Energy and OGE Energy.

Superfund. Comprehensive Environmental Response, Compensation and Liability Act of 1980.

Tailoring Rule. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule. Phases in permitting requirements for stationary sources of GHGs.

TBtu. Trillion British thermal units.

TBtu/d. Trillion British thermal units per day.

Tcf. Trillion cubic feet of natural gas.

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ENABLE™

MIDSTREAM PARTNERS

Common Units
Representing Limited Partner Interests

Prospectus

, 2014

Morgan Stanley
Barclays
Goldman, Sachs & Co.

Until , 2014 (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 and commissions) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the Securities and Exchange Commission registration fee, the FINRA filing fee and the New York Stock Exchange listing fee, the amounts set forth below are estimates:

Securities and Exchange Commission registration fee	$64,400
FINRA filing fee	75,500
New York Stock Exchange listing fee	*
Printing and engraving expenses	*
Legal fees and expenses	*
Accounting fees and expenses	*
Transfer agent and registrar fees	*
Miscellaneous	*
Total	$ *

* To be provided by amendment.

Item 14. Indemnification of Directors and Officers.

Enable Midstream Partners, LP

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 Enable Midstream Partners, LP and our general partner, their officers and directors, and any person who controls our general partner, including indemnification for liabilities under the Securities Act.

Enable 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;
- 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 May 1, 2013, in connection with the formation of Enable Midstream Partners, LP, we issued (i) a non-economic general partner interest to Enable GP, LLC and (ii) a 28.456% limited partner interest in us to OGE Energy and a 13.212% limited partner interest in us to ArcLight in exchange for their contribution of Enogex to us, in each case in an offering exempt from registration under Section 4(a)(2) of the Securities Act. CenterPoint Energy retained a 58.333% limited partner interest in us as a result of these transactions. There have been no other sales of unregistered securities within the past three years.

Item 16. Exhibits and Financial Statement Schedules.

(a) Exhibits.

The following documents are filed as exhibits to this registration statement:

1.1+	Form of Underwriting Agreement
2.1**	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC
3.1**	Certificate of Limited Partnership of CenterPoint Energy Field Services LP, as amended
3.2	Form of Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP (included as Appendix A to the Prospectus)
4.1	Specimen Unit Certificate representing common units (included with Form of Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP)
5.1+	Opinion of Baker Botts L.L.P. relating to the legality of the securities being registered
5.2+	Opinion of Jones Day relating to the legality of the securities being registered
8.1+	Opinion of Baker Botts L.L.P. relating to tax matters
10.1**	Revolving Credit Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP and Citibank, N.A., as administrative agent, UBS Securities LLC, as syndication agent, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association, as co-documentation agents, the several lenders from time to time party thereto and the letter of credit issuers from time to time party thereto
10.2**	Term Loan Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP and Citibank, N.A., as administrative agent, UBS Securities LLC, as syndication agent, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association as co-documentation agents, and the several lenders thereto
10.3**	Term Loan Agreement dated as of August 2, 2012, by and between Enogex LLC and JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Documentation Agent and Union Bank, N.A. and U.S. Bank National Association as Co-Syndication Agents

10.4**	Issuing and Paying Agency Agreement dated as of November 15, 2009, by and between Enogex LLC and UMB Bank, N.A.
10.5**	Issuing and Paying Agency Agreement dated as of June 15, 2009, by and between Enogex LLC and UMB Bank, N.A.
10.6**	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP
10.7**	Services Agreement, dated as of May 1, 2013 between CenterPoint Energy, Inc. and CenterPoint Energy Field Services LP.
10.8**	Services Agreement, dated as of May 1, 2013 between OGE Energy Corp. and CenterPoint Energy Field Services LP.
10.9**	Employee Transition Agreement, dated as of May 1, 2013 among CNP OGE GP LLC, CenterPoint Energy, Inc. and OGE Energy Corp.
10.10**	CNP Transitional Seconding Agreement, dated as of May 1, 2013 between CenterPoint Energy Field Services LP and CenterPoint Energy, Inc.
10.11**	OGE Transitional Seconding Agreement, dated as of May 1, 2013 between CenterPoint Energy Field Services LP and OGE Energy Corp.
10.12**	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CenterPoint Energy Resources Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC
10.13**	OGE Energy Corp. Involuntary Severance Benefits Plans for Officers (applicable only to officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries)
10.14**	Retention Agreement effective as of October 24, 2013, by and between OGE Enogex Holdings, LLC and E. Keith Mitchell
21.1+	Subsidiaries of Enable Midstream Partners, LP
23.1*	Consent of Deloitte & Touche, LLP
23.2*	Consent of Ernst & Young LLP
23.3+	Consent of Baker Botts L.L.P. (contained in Exhibit 5.1)
23.4+	Consent of Jones Day (contained in Exhibit 5.2)
23.5+	Consent of Baker Botts L.L.P. (contained in Exhibit 8.1)
24.1**	Power of Attorney (contained on the signature page of the initial filing of the Registration Statement)
24.2*	Power of Attorney of Lynn L. Bourdon, III and Stephen E. Merrill
99.1*	Consent of Director Nominee (Lynn L. Bourdon, III)

* Filed herewith.
** Previously filed
\+ To be filed by amendment.

(b) Financial Statement Schedules.

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, for the purpose of determining liability of the registrant under the Securities Act to any purchaser in the initial distribution of the securities, 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 this offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to this offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

(iii) The portion of any other free writing prospectus relating to this 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 this offering made by the undersigned registrant to the purchaser.

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.

The undersigned registrant undertakes to send to each common unitholder, at least on an annual basis, a detailed statement of any transactions with OGE Energy, CenterPoint Energy, our general partner, or any of their affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to OGE Energy, CenterPoint Energy, our general partner, or any of their affiliates for the fiscal year completed, showing the amount paid or accrued to each recipient and the services performed.

The 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 registrant.

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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 Oklahoma City in the State of Oklahoma on January 21, 2014.

ENABLE MIDSTREAM PARTNERS, LP

By: ENABLE GP, LLC
Its general partner

By: /s/ E. Keith Mitchell
E. Keith Mitchell
Chief Operating Officer

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
* E. Keith Mitchell	Chief Operating Officer (Principal Executive Officer)	January 21, 2014
* Stephen E. Merrill	Executive Vice President of Finance and Chief Administrative Officer (Principal Financial Officer)	January 21, 2014
* Tom Levescy	Chief Accounting Officer and Controller (Principal Accounting Officer)	January 21, 2014
* Peter B. Delaney	Director	January 21, 2014
* Scott M. Prochazka	Director	January 21, 2014
* Gary L. Whitlock	Director	January 21, 2014
* Sean Trauschke	Director	January 21, 2014

*By: /s/ Mark C. Schroeder
Attorney-in-fact

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99.1*	Consent of Director Nominee (Lynn L. Bourdon, III)

* Filed herewith.
** Previously filed
\+ To be filed by amendment.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use in this Amendment No. 1 to Registration Statement No. 333-192542 of our report dated April 30, 2013 (November 25, 2013 as to Note 14) relating to the combined financial statements of Enable Midstream Partners, LP (previously named CenterPoint Energy Field Services, LLC) and related entities, (collectively the "CenterPoint Midstream Entities") (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the combined financial statements of the CenterPoint Midstream Entities from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries) appearing in the Prospectus, which is a part of this Registration Statement, and to the reference to us under the heading "Experts" in such Prospectus.

/s/ Deloitte & Touche LLP

Houston, Texas
January 21, 2014

Exhibit 23.2

CONSENT OF INDEPENDENT AUDITORS

We consent to the reference to our firm under the caption "Experts" and to the use of our report dated February 27, 2013 with respect to the consolidated financial statements of Enogex LLC in the Registration Statement (Amendment No. 1 to Form S-1) of Enable Midstream Partners, LP.

/s/ ERNST & YOUNG LLP

Oklahoma City, Oklahoma
January 20, 2014

Exhibit 24.2

ENABLE MIDSTREAM PARTNERS, LP

Power of Attorney

Each person whose signature appears below appoints Mark C. Schroeder and J. Brent Hagy, and each of them, any of whom may act without the joinder of the other, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign the Registration Statement on Form S-1 of Enable Midstream Partners, LP (File No. 333-192542) (the "Registration Statement") and any and all amendments (including post-effective amendments) thereto and any registration statement (including any amendment thereto) for the offering contemplated by the Registration Statement that is to be effective upon filing pursuant to Rule 462(b) under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned has caused this Power of Attorney to be executed as of this 21st day of January, 2014.

/s/ Lynn L. Bourdon, III
By: Lynn L. Bourdon, III

/s/ Stephen E. Merrill
By: Stephen E. Merrill

Exhibit 99.1

Consent of Director Nominee

Pursuant to Rule 438 of Regulation C promulgated under the Securities Act of 1933, as amended (the "**Securities Act**"), in connection with the Registration Statement on Form S-1 (the "**Registration Statement**") of Enable Midstream Partners, LP, the undersigned hereby consents to being named and described as a director nominee of Enable GP, LLC in the Registration Statement and any amendment or supplement to any prospectus included in such Registration Statement, any amendment to such Registration Statement or any subsequent Registration Statement filed pursuant to Rule 462(b) under the Securities Act and to the filing or attachment of this consent with such Registration Statement and any amendment or supplement thereto.

IN WITNESS WHEREOF, the undersigned has executed this consent as of the 16th day of January, 2014.

/s/ Lynn L. Bourdon, III

Lynn L. Bourdon, III