EnLink Midstream, LLC
Form 10-K
March 31, 2014
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 10-K

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2013

OR

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

for the transition period from to

Commission file number: 001-36336

ENLINK MIDSTREAM, LLC

DELAWARE	**46-4108528**
(State of organization)	(I.R.S. Employer Identification No.)

2501 CEDAR SPRINGS RD. **DALLAS, TEXAS**	**75201**
(Address of principal executive offices)	(Zip Code)

(Exact name of registrant as specified in its charter)

(214) 953-9500

(Registrant s telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	**Name of Exchange on which Registered**
Common Units Representing Limited Liability Company Interests	The New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: **None.**

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

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

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

As of June 30, 2013, the last business day of the registrant s most recently completed second fiscal quarter, there was no public market for the registrant s common units. The registrant s common units began trading on the New York Stock Exchange (NYSE) on March 10, 2014.

At March 24, 2014, there were 48,512,295 common units and 115,495,669 Class B common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

TABLE OF CONTENTS

Table of Contents

ENLINK MIDSTREAM, LLC

PART I

Item 1. ***Business***

General

EnLink Midstream, LLC (ENLC or the Company) is a Delaware limited liability company formed in October 2013. Effective as of March 7, 2014, EnLink Midstream, Inc. (formerly known as Crosstex Energy, Inc.) (EMI) merged with and into a wholly-owned subsidiary of the Company and Acacia Natural Gas Corp I, Inc. (New Acacia), formerly a wholly-owned subsidiary of Devon Energy Corporation (Devon), merged with and into a wholly-owned subsidiary of the Company (collectively, the mergers). Pursuant to the mergers, each of EMI and New Acacia became wholly-owned subsidiaries of the Company and the Company became publicly held. EMI owns common units representing an approximate 7% limited partner interest in EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) (the Partnership) as of March 24, 2014 and also owns EnLink Midstream Partners GP, LLC (formerly known as Crosstex Energy GP, LLC) (the General Partner). New Acacia directly owns a 50% limited partner interest in EnLink Midstream Holdings, LP (Midstream Holdings). Midstream Holdings formerly was a wholly-owned subsidiary of Devon.

Concurrently with the consummation of the mergers, a wholly-owned subsidiary of the Partnership acquired the remaining 50% of the outstanding limited partner interest in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings (together with the mergers, the business combination).

The Company s common units are traded on the New York Stock Exchange under the symbol ENLC. Our executive offices are located at 2501 Cedar Springs Rd., Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.enlink.com. In the Investors section of our website, we post the following filings as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual reports on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our website are available free of charge.

In this report, the terms Company or Registrant as well as the terms ENLC, our, we, and us, or like terms, are sometimes used as referenc EnLink Midstream, LLC and its consolidated subsidiaries. References in this report to EnLink Midstream Partners, LP , the Partnership, ENLK or like terms refer to EnLink Midstream Partners, LP itself or EnLink Midstream Partners, LP together with its consolidated subsidiaries other than Midstream Holdings, and Midstream Holdings is sometimes used to refer to EnLink Midstream Holdings, LP itself or to EnLink Midstream Holdings, LP together with EnLink Midstream Holdings GP, LLC and their subsidiaries. References in this report to the Midstream Entities refer to EnLink Midstream Partners, LP and Midstream Holdings, together with their consolidated subsidiaries.

Our assets consist of equity interests in EnLink Midstream Partners, LP, EnLink Midstream Holdings, LP, E2 Energy Services, LLC and E2 Appalachian Compression, LLC (collectively, E2). EnLink Midstream Partners, LP is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. EnLink Midstream Holdings, LP is a partnership held by us and the Partnership engaged in the gathering, transmission and processing of natural gas. E2 is a services company focused on the Utica Shale play in the Ohio River Valley. Our interests in EnLink Midstream Partners, LP, EnLink Midstream Holdings, LP and E2 consist of the following:

- 16,414,830 common units representing an aggregate 7% limited partner interest in the Partnership as of March 24, 2014;

- 100.0% ownership interest in EnLink Midstream Partners GP, LLC, the general partner of the Partnership, which owns a 0.7% general partner interest as of March 24, 2014 and all of the incentive distribution rights in the Partnership;

- 50.0% limited partner interest in Midstream Holdings as of March 24, 2014; and

Table of Contents

- 93.7% interest in E2 Energy Services, LLC and a 92.5% interest in E2 Appalachian Compression, LLC, with the remainder owned by E2 management, as of March 24, 2014.

Each of the Partnership and Midstream Holdings is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership s or Midstream Holdings business, as applicable, or to provide for future distributions. Other than with respect to distributions to cover tax liabilities allocated to the members, the limited liability company agreements of each of E2 Energy Services, LLC and E2 Appalachian Compression, LLC provide that distributions will be made to the members at such time and in such amounts as determined by the board of directors of the applicable entity.

The incentive distribution rights in the Partnership entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

We intend to pay distributions to our unitholders on a quarterly basis equal to the cash we receive, if any, from distributions from the Partnership and Midstream Holdings and, if applicable, E2, less reserves for expenses, future distributions and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner s then-current general partner interest, to the extent the board of directors of the general partner exercises its option to do so; and
- cash reserves our board of directors believes are prudent to maintain.

Our ability to pay distributions is limited by the Delaware Limited Liability Company Act, which provides that a limited liability company may not pay distributions if, after giving effect to the distribution, the company s liabilities would exceed the fair value of its assets. While our ownership of equity interests in the general partner, the Partnership, Midstream Holdings and E2 are included in our calculation of net assets, the value of these assets may decline to a level where our liabilities would exceed the fair value of our assets if we were to pay distributions, thus prohibiting us from paying distributions under Delaware law.

ENLINK MIDSTREAM PARTNERS, LP

EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) is a publicly traded Delaware limited partnership formed in 2002. The Partnership s common units are traded on the New York Stock Exchange under the symbol ENLK. The Partnership s business activities are conducted through its subsidiary, EnLink Midstream Operating, LP (formerly known as Crosstex Energy Services, L.P.), a Delaware limited partnership (the Operating Partnership), and the subsidiaries of the Operating Partnership. The Partnership s executive offices are located at 2501 Cedar Springs Rd., Dallas, Texas 75201, and its telephone number is (214) 953-9500. The Partnership s Internet address is www.enlink.com. The Partnership posts the following filings in the Investors section of its website as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: the Partnership s annual reports on Form 10-K; the Partnership s quarterly reports on Form 10-Q; the Partnership s current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on the Partnership s website are available free of charge.

EnLink Midstream GP, LLC (formerly known as Crosstex Energy GP, LLC), a Delaware limited liability company and our wholly-owned subsidiary, is the Partnership s general partner (the General Partner). The General Partner manages the Partnership s operations and activities.

ENLINK MIDSTREAM HOLDINGS, LP

EnLink Midstream Holdings, LP was formed in 2013 to hold substantially all of the midstream assets formerly held by Devon. We acquired a 50% limited partner interest in Midstream Holdings upon the consummation of the business combination. Midstream Holdings gathers, processes and transports natural gas, primarily for Devon. Midstream Holdings also fractionates NGLs into component NGL products. EnLink Midstream Holdings GP, LLC, a Delaware limited liability company and a wholly-owned subsidiary of the Partnership, is the general partner of Midstream Holdings and manages Midstream Holdings operations and activities.

Table of Contents

E2 ENERGY SERVICES, LLC AND E2 APPALACHIAN COMPRESSION, LLC

E2 was formed in March 2013 to provide services for producers in the liquids-rich window of the Utica Shale play. E2 will build, own and operate three new natural gas compression and condensate stabilization facilities located in Noble and Monroe counties in the southern portion of the Utica Shale play in Ohio. We own approximately 93.7% of E2 Energy Services, LLC and approximately 92.5% of E2 Appalachian Compression, LLC, with the remainder owned by E2 management. We have pre-determined rights to purchase the management ownership interests of E2 in the future.

Table of Contents

The following diagram depicts the organization and ownership of us and our subsidiaries as of March 24, 2014:

Definitions

The following terms as defined generally are used in the energy industry and in this document:

/d = per day

Bbls = barrels

Bboe = billion Boe

Table of Contents

Bcf = billion cubic feet

Boe = six Mcf of gas per Bbl of oil

Btu = British thermal units

CO_2= Carbon dioxide

Mcf = thousand cubic feet

MMBtu = million British thermal units

MMcf = million cubic feet

NGL = natural gas liquid and natural gas liquids

Capacity volumes at the Partnership s and Midstream Holdings facilities are measured based on physical volume and stated in cubic feet (Bcf, Mcf or MMcf). Throughput volumes are measured based on energy content and stated in British thermal units (Btu or MMBtu). A volume capacity of 100 MMcf generally correlates to volume capacity of 100,000 MMBtu. Fractionated volumes are measured based on physical volumes and stated in gallons. Crude oil, condensate and brine services volumes are measured based on physical volume and stated in barrels (Bbls).

Our Operations

The Midstream Entities primarily focus on providing midstream energy services, including gathering, transmission, processing, fractionation and marketing, to producers of natural gas, NGLs, crude oil and condensate. The Partnership also provides crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 7,300 miles of pipelines, 12 natural gas processing plants, six fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks.

Our assets are comprised of systems and other assets owned by Midstream Holdings, in which we hold a 50% interest and the Partnership holds the remaining 50% interest, as well as systems and other assets in which the Partnership holds an interest through its wholly-owned subsidiaries, and are located in four primary regions:

- *Texas*. Our Texas assets consist of transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.1 Bcf/d and gathering systems with total capacity of approximately 2.5 Bcf/d. Some of the primary assets comprising our Texas assets are as follows:

- *North Texas Pipeline and Acacia transmission system*. The Partnership s North Texas Pipeline (NTPL) is a 140-mile pipeline that connects production from the Barnett Shale to markets in north Texas with approximately 375 MMcf/d of capacity. Average throughput on the NTPL was approximately 342,000 MMBtu/d for the year ended December 31, 2013. The Acacia transmission system, which is owned by Midstream Holdings, consists of approximately 120 miles of pipeline and associated storage with approximately 920 MMcf/d of capacity. Average throughput on the Acacia transmission system was approximately 741,800 MMBtu/d for the year ended December 31, 2013.

- *Bridgeport processing facility*. The Bridgeport processing facility, which is owned by Midstream Holdings, is one of the largest processing plants in the U.S. with 790 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity. Average throughput on the Bridgeport processing facility was 810,600 MMBtu/d for the year ended December 31, 2013.

- *Silver Creek processing complex*. The Partnership s Silver Creek processing complex includes three processing plants with an aggregate of 285 MMcf/d of processing capacity. Average throughput on the Silver Creek processing complex was 316,000 MMBtu/d for the year ended December 31, 2013.

- *Permian Basin Assets*. The Partnership s Permian Basin assets consist of its Deadwood natural gas processing plant, which has a total processing capacity of 58 MMcf/d and in which the Partnership has a 50% undivided working interest, and its Mesquite Terminal fractionator, which has 15,000 Bbls/d of NGL fractionation capacity. Average throughput on the Deadwood natural gas processing plant was 66,000 MMBtu/d for the year ended December 31, 2013.

- *Gulf Coast Fractionators*. Midstream Holdings is entitled to receive the economic benefits and burdens of the 38.75% interest in Gulf Coast Fractionators held by Devon. Gulf Coast Fractionators owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. The facility has a capacity of approximately 145 MBbls/d.

- *Bridgeport and East Johnson County gathering systems*. The Bridgeport and East Johnson County gathering systems, which are owned by Midstream Holdings, are comprised of three natural gas gathering systems in the Barnett Shale, consisting of an aggregate of approximately 3,010 miles of gathering lines with an aggregate capacity of approximately 1.4 Bcf/d. These gathering systems had an aggregate average throughput of approximately 1,359,700 MMBtu/d for the year ended December 31, 2013.

Table of Contents

- *Silver Creek gathering systems*. The Partnership s Silver Creek gathering systems consists of approximately 715 miles of gathering lines that have a total capacity of approximately 1.1 Bcf/d, with average throughput of approximately 700,000 MMBtu/d for the year ended December 31, 2013.

- *Howard Energy Partners*. Howard Energy Partners, or HEP, owns and operates over 500 miles of pipeline and a 200 MMcf/d processing plant, serving production from the Eagle Ford, Escondido, Olmos, Pearsall and other formations in south Texas. HEP s system has 145 MMcf/d of amine treating capacity and more than 9,000 horsepower of compression. As of December 31, 2013, the Partnership owned a 30.6% interest in HEP.

- *Oklahoma*. Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d and gathering systems with total capacity of approximately 605 MMcf/d. All of our Oklahoma assets are owned by Midstream Holdings and are comprised of the following:

- *Cana System*. The Cana system is a natural gas gathering and processing system located in the Cana-Woodford Shale in West Central Oklahoma. The Cana system includes a 350 MMcf/d processing facility. The Cana system also consists of approximately 413 miles of gathering lines that have a total capacity of approximately 530 MMcf/d and had an average throughput of approximately 320,700 MMBtu/d for the year ended December 31, 2013.

- *Northridge System*. The Northridge system is a natural gas gathering and processing system located in the Arkoma-Woodford Shale in Southeastern Oklahoma. The Northridge system includes a 200 MMcf/d processing facility. The Northridge system also consists of approximately 140 miles of gathering lines that have a total capacity of approximately 75 MMcf/d and had an average throughput of approximately 69,200 MMBtu/d for the year ended December 31, 2013.

- *Louisiana*. The Partnership s Louisiana assets consist of transmission pipelines with a capacity of approximately 2.0 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d. The Partnership s Louisiana assets are as follows:

- *LIG Assets*. The LIG system includes gathering and transmission systems with total capacity of approximately 2.0 Bcf/d, processing facilities with a total processing capacity of approximately 335 MMcf/d and fractionation facilities with total capacity of 10,800 Bbls/d.

- The Partnership s LIG gathering and transmission pipeline system is one of the largest intrastate pipeline systems in Louisiana, consisting of approximately 2,000 miles of mainly transmission pipelines extending from the Haynesville Shale in north Louisiana to onshore production in south central and southeast Louisiana, which have approximately 2.0 Bcf/d of capacity. Average throughput on the LIG pipeline system was approximately 473,000 MMBtu/d for the year ended December 31, 2013.

• The LIG system also includes two processing facilities with a total processing capacity of 335 MMcf/d. Average throughput on the LIG processing facilities was 255,000 MMBtu/d for the year ended December 31, 2013.

• The Plaquemine plant forming part of the Partnership s LIG system has a fractionation capacity of 10,800 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine averaged approximately 4,800 Bbls/d for the year ended December 31, 2013.

• *South Louisiana Processing and NGL Assets.* The Partnership s south Louisiana natural gas processing and NGL assets include 570 miles of liquids transport lines, approximately 1.4 Bcf/d of processing capacity and 3.1 million barrels of underground NGL storage.

• *Cajun-Sibon Pipeline System.* Currently, the Cajun-Sibon pipeline system consists of approximately 570 miles of raw make NGL pipelines with a current system capacity of approximately 70,000 Bbls/d. Average throughput on the Cajun-Sibon system was approximately 28,500 Bbls/d for the fourth quarter of 2013 when the new expanded pipeline commenced operation.

• *Processing Facilities.* The Partnership s processing facilities in south Louisiana include three gas processing plants with total processing capacity of 1.4 Bcf/d and throughput that averaged 399,000 MMBtu/d for the year ended December 31, 2013. The Partnership also has two fractionation facilities that have a capacity of 83,000 Bbls/d with throughput that averaged 27,300 Bbls/d for the year ended December 31, 2013.

• *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Partnership s Riverside facility and has a total capacity of 3.1 million barrels of underground storage comprised of two existing caverns.

• *Ohio River Valley.* The Partnership s Ohio River Valley operations are an integrated network of assets comprised of a 4,500-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot operation crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks. The Partnership has eight existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d. The

Table of Contents

Partnership currently holds one additional brine well permit in Ohio. Additionally, the assets held by E2, in which our wholly-owned subsidiary owned approximately 93.7% of E2 Energy Services, LLC and approximately 92.5% of E2 Appalachian Compression, LLC, consist of three gas gathering compressor stations and condensate stabilization assets located in Noble and Monroe counties in the southern portion of the Utica Shale play in Ohio. The compressor stations have a total capacity of 340 MMcf/d and 44,000 horsepower of compression with condensate handling capacity of 16,000 Bbls/d. Commercial operations of one of the facilities, which we refer to as Upper Hill, commenced during January 2014. None of these facilities were in service as of December 31, 2013.

About Devon

Devon (NYSE: DVN) is a leading independent energy company engaged primarily in the exploration, development and production of crude oil, natural gas and NGLs. Devon s operations are concentrated in various onshore areas in the U.S. and Canada. As of December 31, 2013, Devon had a total equity market capitalization of over $25 billion and an investment-grade credit rating.

Pursuant to various gathering and processing agreements, Devon has dedicated approximately 795,000 net acres to Midstream Holdings. Please read Midstream Holdings Contractual Relationship with Devon below. Devon had approximately 2.2 BBoe of proved reserves in the U.S. as of December 31, 2013, of which approximately 1.2 BBoe, or 55%, was associated with this dedicated acreage. For the year ended December 31, 2013, Devon s average U.S. production was 517 MBoe/d, with approximately 240 MBoe/d, or 46%, associated with this dedicated acreage.

Devon is the largest natural gas producer in the Barnett and Cana-Woodford Shales, the largest NGL producer in the Barnett Shale and one of the largest NGL producers in the Cana-Woodford Shale. In 2013, Devon drilled 172 gross wells in the Barnett Shale with exploration and production capital expenditures of $530 million and drilled 118 gross wells in the Cana-Woodford Shale with exploration and production capital expenditures of approximately $560 million. As of December 31, 2013, Devon held 610,000 net acres in the Barnett Shale, 245,000 net acres in the Cana-Woodford Shale and 40,000 net acres in the Arkoma-Woodford Shale. Devon has drilled over 5,000 gross wells in the Barnett Shale since 2002 and in 2014 expects to drill approximately 90 gross wells with budgeted exploration and production capital expenditures of approximately $250 million. In the Cana-Woodford Shale, Devon expects to drill approximately 65 gross wells in 2014 with budgeted exploration and production capital expenditures of approximately $150 million. In addition to its current drilling schedule, Devon has identified thousands of additional drilling locations in each of these areas.

Our Business Strategies

Our primary business objective is to increase our cash available for distributions to our unitholders over time, which can only be achieved if the Partnership and Midstream Holdings execute the following strategies:

- *Organic Growth: pursue opportunities around the Midstream Entities existing footprint.* The Midstream Entities expect to grow certain of their systems organically over time by meeting Devon s and their other customers midstream service needs that result from their drilling activity in the Midstream Entities areas of operation. The Midstream Entities continually evaluate economically attractive organic expansion opportunities in existing or new areas of operation that allow the Midstream Entities to leverage their existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand for the Midstream Entities services.

- *Dropdowns: maximize opportunities provided by Devon s sponsorship and assets held by the Company*. The Midstream Entities plan to execute their growth in part through pursuing accretive dropdown opportunities from Devon and the Company. The Midstream Entities expect to be given the opportunity over time to purchase the remaining 50% interest in Midstream Holdings held by us. The Partnership is a party to a preferential rights agreement with us and our wholly-owned subsidiary pursuant to which we granted the Partnership a right of first refusal, for a period of 10 years, with respect to (i) our interest in E2 and (ii) Devon s 50% interest in the Access Pipeline transportation system, to the extent in the future we obtain such interest pursuant to a first offer agreement between Devon and us. The Midstream Entities also believe there will continue to be significant opportunities as Devon continues to develop its oil and gas production. However, the Midstream Entities cannot be certain that these opportunities will be made available to them, or that they will choose to pursue any such opportunity.

- *Acquisitions: pursue strategic and accretive acquisitions*. The Midstream Entities pursue strategic and accretive acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and geographic areas of operation.

- *Strong Balance Sheet: maintain an investment grade quality financial profile*. The Midstream Entities intend to maintain appropriate leverage and distribution coverage levels in line with other partnerships in the Midstream Entities sector that have received investment grade credit ratings. By maintaining an investment grade quality financial profile, the Midstream Entities believe that they will be able to pursue strategic acquisitions and large growth projects at a lower cost of capital, which enhances their competitiveness.

Table of Contents

Our Competitive Strengths

We believe that the Partnership and Midstream Holdings are well-positioned to execute their business strategies and to achieve their business objectives due to the following competitive strengths:

- *Devon s sponsorship*. The Midstream Entities expect their relationship with Devon will continue to provide them with significant business opportunities. Devon is one of the largest independent oil and gas producers in North America. Devon has a significant interest in promoting the success of the Midstream Entities business, due to its approximate 70% ownership interest in us and approximate 53% ownership interest in the Partnership.

- *Strategically-located assets*. The Midstream Entities assets are strategically located in areas with the potential for increasing throughput volume and cash flow generation. The Midstream Entities asset portfolio includes gathering and processing systems located in areas in which producer activity is focused on crude oil, condensate and NGLs. The Midstream Entities estimate that these liquids-focused production areas will generate approximately 75% of their combined 2014 gross operating margin. Due to the relatively high current price of crude oil and condensate as compared to natural gas, production in these areas offers the Midstream Entities customers higher margins and superior economics compared to basins in which the gas is relatively dry. This pricing environment offers expansion opportunities for certain of the Midstream Entities systems as producers attempt to increase their rich gas, crude oil and condensate production.

- *Stable cash flows*. Approximately 95% of the Midstream Entities combined cash flows are expected to be derived from fee-based services with no direct commodity exposure. Midstream Holdings has entered into 10-year, fixed-fee gathering and processing agreements with a subsidiary of Devon pursuant to which Midstream Holdings or its subsidiary will provide gathering, treating, compression, dehydration, stabilization, processing and fractionation services, as applicable, for natural gas delivered by Devon to Midstream Holdings gathering and processing systems in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. These agreements provide Midstream Holdings with dedication of all of the natural gas owned or controlled by Devon and produced from or attributable to existing and future wells located on certain oil, natural gas and mineral leases covering lands within the acreage dedications, excluding properties previously dedicated to other natural gas gathering systems not owned and operated by Devon. These agreements also include five-year minimum volume commitments and annual rate escalators. Please read Midstream Holdings Contractual Relationship with Devon. The Midstream Entities will continue to focus on contract structures that reduce volatility and support long-term stability of cash flows.

- *Integrated midstream services*. The Midstream Entities span the energy value chain by providing natural gas, NGL, crude oil, condensate and water services across a diverse customer base. These services include gathering, compressing, treating, processing, transporting, storing and selling natural gas, producing, fractionating, transporting, storing and selling NGLs, and gathering, transporting, storing and trans-loading crude oil and condensate. The Midstream Entities believe their ability to provide all of these services gives them an advantage in competing for new opportunities because they can provide substantially all services that producers, marketers and others require to move natural gas, NGLs, crude oil and condensate from the wellhead to the market on a cost-effective basis.

- *Financial flexibility to pursue expansion and acquisition opportunities*. The Midstream Entities believe their stable cash flows, strong balance sheet and access to debt and equity capital markets provide them with the financial flexibility to competitively pursue acquisition and expansion opportunities and to execute their strategy across capital market cycles.

• *Experienced management team.* The Midstream Entities believe their management team has a proven track record of creating value through the development, acquisition, optimization and integration of midstream assets. The Midstream Entities management team has an average of over 20 years of experience in the energy industry. The Midstream Entities believe this team provides us with a strong foundation for evaluating growth opportunities and operating our assets in a safe, reliable and efficient manner.

We believe that the Midstream Entities will leverage their competitive strengths to successfully implement their strategy; however, their business involves numerous risks and uncertainties that may prevent the Midstream Entities from achieving their primary business objective. For a more complete description of the risks associated with the Midstream Entities businessplease see Item 1A. Risk Factors.

Midstream Holdings Contractual Relationship with Devon

Upon the consummation of the business combination, Midstream Holdings entered into a 10-year transportation contract with Devon for the Acacia transmission system as well as the following additional fee-based agreements with Devon:

Contract	Contract Term (Years)	Minimum Gathering Volume Commitment (MMcf/d)	Minimum Processing Volume Commitment (MMcf/d)	Minimum Volume Commitment Term (Years)	Annual Rate Escalators
Bridgeport gathering and processing contract(1)	10	850	650	5	CPI
East Johnson County gathering contract	10	125		5	CPI
Northridge gathering and processing contract	10	40	40	5	CPI
Cana gathering and processing contract	10	330	330	5	CPI

(1) The Bridgeport gathering and processing contract includes volume commitments to the Bridgeport processing facility as well as the Bridgeport gathering systems.

Table of Contents

Recent Growth Developments

Cajun-Sibon Phases I and II. In Louisiana, the Partnership is transforming its business that historically has been focused on processing offshore natural gas to a business that is focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market historically has relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II will work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

The Partnership began this transformation by restarting its Eunice fractionator during 2011 at a rate of 15,000 Bbls/d of NGLs. The Partnership expanded the Eunice fractionator to a rate of 55,000 Bbls/d with Cajun-Sibon Phase I (Phase I). Phase I of the Partnership s pipeline extension project was completed in November 2013 and connects Mont Belvieu supply lines in east Texas to Eunice, providing a direct link to its fractionators in south Louisiana markets. The Phase I Eunice fractionator expansion, which also was completed in early November 2013, has increased the Partnership s interconnected fractionation capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs.

The Phase I expansion added 130-miles of 12-inch diameter pipeline to the Partnership s existing 440-mile Cajun-Sibon NGL pipeline system, connecting Mont Belvieu to the Partnership s Eunice fractionator. Phase I of the pipeline currently has a capacity of 70,000 Bbls/d for raw make NGLs. The Phase I NGL pipeline extension originates from interconnects with major Mont Belvieu supply pipelines and provides connections for NGLs from the Permian Basin, Barnett Shale, Eagle Ford and other areas to the Partnership s NGL fractionation facilities and key NGL markets in south Louisiana. Phase I is anchored by a five-year ethane sales agreement with Williams Olefins, a subsidiary of the Williams Companies, and a five year natural gasoline sales agreement with another company. The Partnership has entered into yearly sales agreements for all other purity products.

The Partnership has commenced construction of Cajun-Sibon Phase II which will further enhance its Louisiana NGL business with significant additions to the Cajun-Sibon Phase I infrastructure including further fractionation expansion. Phase II will include the addition of four pumping stations, totaling 13,400 horsepower, that will facilitate increasing NGL supply capacity from Phase I s 70,000 Bbls/d to 120,000 Bbls/d; the construction of a new 100,000 Bbls/d fractionator at the Plaquemine gas processing plant site; the conversion of the Partnership s Riverside fractionator to a butane-and-heavier facility; and the construction of 57 miles of NGL pipeline that will originate at the Eunice fractionator and connect to the new Plaquemine fractionator, which will provide optionality to move purity products around the Louisiana-liquids market. The Partnership will also construct a 32-mile, 16-inch diameter extension of LIG s Bayou Jack lateral, which will provide gas services to customers in the Mississippi River corridor, replacing the conversion of supply lines that the Partnership currently uses for liquid service. The Partnership expects Phase II will be in service during the second half of 2014.

Phase II is anchored by 10-year sales agreements with Dow Hydrocarbons and Resources, or Dow, to deliver up to 40,000 Bbls/d of ethane and 25,000 Bbls/d of propane produced at the Partnership s new Plaquemine fractionator into Dow s Louisiana pipeline system. The Partnership will also deliver 70,000 MMBtu/d of natural gas to Dow s Plaquemine facility.

The Partnership believes the Cajun-Sibon project not only represents a tremendous growth step by leveraging its Louisiana assets, but that it also creates a significant platform for continued growth of our NGL business. The Partnership believes this project, along with its existing assets, will provide a number of additional opportunities to grow this business, including expanding market optionality and connectivity, upgrading products, expanding rail imports, exporting NGLs and expanding fractionation and product storage capacity.

Bearkat Natural Gas Gathering and Processing System. In the fourth quarter of 2013, the Partnership commenced construction of a new natural gas processing complex and rich gas gathering pipeline system in the Permian Basin. The initial construction included treating, processing and gas takeaway solutions for regional producers. The project, which will be fully owned by the Partnership, is supported by a 10-year, fee-based contract.

The new-build processing complex, called Bearkat, will be strategically located near the Partnership s existing Deadwood joint venture assets in Glasscock County, Texas. The processing plant will have an initial capacity of 60 MMcf/d, increasing the Partnership s total operated processing capacity in the Permian to approximately 115 MMcf/d. The Partnership will also construct a 30-mile high-pressure gathering system upstream of the Bearkat complex to provide additional gathering capacity for producers in Glasscock and Reagan Counties.

Additionally, in February 2014, the Partnership entered into an agreement to construct a new 35-mile, 12-inch diameter high-pressure pipeline that will provide critical gathering capacity for the Bearkat natural gas processing complex. The pipeline will have a capacity of approximately 100 MMcf/d and will provide gas takeaway solutions for constrained producer customers in Howard, Martin and Glasscock counties. The entire project is expected to be completed in the second half of 2014.

Table of Contents

Riverside Crude Facility Expansion. In June 2013, the Partnership completed the Phase II expansion of its Riverside facility located on the Mississippi River in southern Louisiana. The Riverside facility s capacity to transload crude oil and condensate from railcars to the Partnership s barge facility increased to approximately 15,000 Bbls/d of crude oil and condensate. Phase II additions to the Riverside facility include a 100,000 barrel above-ground crude oil and condensate storage tank, a rail spur with a 26-spot crude oil and condensate railcar unloading rack and a crude offloading facility with pumps and metering as well as a truck unloading bay. As part of the Phase II expansion, the Riverside facility was modified so that sour crude can be unloaded in addition to sweet crude.

Our Assets

Our assets consist of gathering systems and transmission pipelines, processing and fractionation facilities, storage facilities and ancillary assets. The following tables provide information about our assets as of and for the year ended December 31, 2013:

Gathering and Transmission Pipelines	Approximate Length (Miles)	Compression(1) (HP)	Estimated Capacity (MMcf/d)	Year Ended December 31, 2013 Average Throughput (Thousands of MMBtu/d)
Texas Assets:				
Partnership Assets	855	131,834	1,475	1,042,000
Midstream Holdings Assets*	3,132	261,266	2,330	2,101,500
Oklahoma Assets:				
Cana System*	413	92,499	530	320,700
Northridge System*	140	17,895	75	69,200
Louisiana Assets:				
LIG System	1,925	83,378	1,965	473,000
South Louisiana Assets	570		(2)	(3)
Total	7,035	586,872	6,375	4,006,400

Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which we hold a 50% interest and the Partnership holds the remaining 50% interest as of March 24, 2014.

(1) Includes power generation units.

(2) Estimated capacity for South Louisiana liquid pipeline transportation is 70 MBbls/d.

(3) Average throughput on the expanded Cajun-Sibon pipeline, which commenced operations in October 2013, was 28,500 Bbls/d for the fourth quarter of 2013.

Processing Facilities	Processing Capacity (MMcf/d)	Year Ended December 31, 2013 Average Throughput (MMBtu/d)
Texas Assets		
Partnership Assets	314	349,000
Midstream Holdings Assets*	790	810,600
Oklahoma Assets		
Cana System*	350	278,700
Northridge System*	200	121,000
Louisiana Assets		
LIG Assets	335	255,000
South Louisiana Assets	1,375	399,000
Total	3,364	2,213,300

Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which we hold a 50% interest and the Partnership holds the remaining 50% interest as of March 24, 2014.

Fractionation Facilities	Estimated NGL Fractionation Capacity (MBbls/d)	Average Throughput (MBbls/d)
Texas Assets		
Partnership Assets	15	(2)
Midstream Holdings Assets*	15	(2)
Louisiana Assets		
LIG Assets	11	5
South Louisiana Assets	83	27
Gulf Coast Fractionators(1)	56	44
Total	180	76

Assets wholly-owned by the Partnership.

* Assets owned by Midstream Holdings, in which we hold a 50% interest and the Partnership holds the remaining 50% interest as of March 24, 2014.

(1) Volumes are shown net to Midstream Holdings net contractual right to the burdens and benefits of a 38.75% economic interest in Gulf Coast Fractionators held by Devon.

(2) The Partnership s Texas fractionation facility is connected to its Deadwood processing plant in the Permian Basin and the Midstream Holdings fractionation facility is connected to our Bridgeport processing plant. These fractionation facilities provide operational flexibility for the related processing plants, but are not the primary fractionation facilities for the NGLs produced by the processing plants. Under the Partnership s current contracts, it does not earn fractionation fees for operating these fractionation facilities so throughput volumes through these facilities are not captured on a routine basis and are not significant to its operating margins.

Table of Contents

Texas Assets. Our Texas assets consist of systems and other assets owned by Midstream Holdings, in which we own a 50% interest and the Partnership holds the remaining 50% interest, as well as systems and other assets in which the Partnership holds an interest through its wholly-owned subsidiaries. These assets include transmission pipelines with a capacity of approximately 1.3 Bcf/d, processing facilities with a total processing capacity of approximately 1.1 Bcf/d and gathering systems with total capacity of approximately 2.5 Bcf/d.

• *Transmission Systems*. Our transmission systems in Texas include approximately 260 miles of pipeline with an aggregate capacity of approximately 1.3 Bcf/d and consist of the following:

• *North Texas Pipeline*. The Partnership s North Texas Pipeline (NTPL) is a 140-mile pipeline extending from an area near Fort Worth, Texas to a point near Paris, Texas and connects production from the Barnett Shale to markets in north Texas accessed by the Natural Gas Pipeline Company of America, LLC, Kinder Morgan, Inc., Houston Pipeline Company, L.P., Atmos Energy Corporation and Gulf Crossing Pipeline Company, LLC. The NTPL has approximately 375 MMcf/d of capacity and 18,960 horsepower of compression and, for the year ended December 31, 2013, the average throughput on the NTPL was approximately 342,000 MMBtu/d.

• *Acacia transmission system*. The Acacia transmission system, which is owned by Midstream Holdings, is a 120-mile pipeline that connects production from the Barnett Shale to markets in north Texas accessed by Atmos Energy, Brazos Electric, Enbridge Energy Partners, Energy Transfer Partners, Enterprise Product Partners and GDF Suez. The Acacia transmission system has approximately 920 MMcf/d of capacity and 17,000 horsepower of compression and, for the year ended December 31, 2013, average throughput was approximately 741,800 MMBtu/d. Devon is the Acacia transmission system s only customer and has entered into a 10-year transportation agreement that covers transmission services on the Acacia transmission pipeline and includes annual rate escalators.

• *Processing Facilities*. Our processing facilities in Texas include five gas processing plants with total processing throughput that averaged 1,159,600 MMBtu/d for the year ended December 31, 2013 and consist of the following:

• *Bridgeport processing facility*. Our Bridgeport natural gas processing facility, located in Wise County, Texas, approximately 40 miles northwest of Fort Worth, Texas, is owned by Midstream Holdings and is one of the largest processing plants in the U.S. with seven cryogenic turboexpander plants that have an aggregate of 790 MMcf/d of processing capacity and 15 MBbls/d of NGL fractionation capacity. For the year ended December 31, 2013, throughput volumes at the Bridgeport processing facility averaged 810,600 MMBtu/d of natural gas. Devon is the Bridgeport facility s largest customer with approximately 744,600 MMBtu/d of natural gas processed for the year ended December 31, 2013, which represented approximately 92% of the total volumes processed at the facility during such period. Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering and processing agreement pursuant to which Midstream Holdings will provide processing services for natural gas delivered by Devon to the Bridgeport processing facility. This contractual arrangement includes a five-year minimum volume commitment from Devon of 650 MMcf/d of natural gas delivered to the Bridgeport processing facility as well as annual rate escalators.

• *Silver Creek processing complex*. The Partnership s Silver Creek processing complex, located in Weatherford, Azle and Fort Worth, Texas, includes three processing plants. The Partnership s Silver Creek plants have a total of 285 MMcf/d of processing capacity, with the Azle Plant, Silver Creek Plant and Goforth Plant accounting for 50 MMcf/d, 200 MMcf/d and 35 MMCf/d of processing capacity, respectively. For the year ended December 31, 2013, throughput volumes at the Silver Creek processing facility averaged 316,000 MMBtu/d of natural gas.

- *Permian Basin assets*. The Partnership s Permian Basin assets consist of its Deadwood natural gas processing plant and our Mesquite Terminal fractionator. The Partnership has a 50% undivided working interest in the Deadwood processing facility which is located in Glasscock County, Texas. The Deadwood plant is supported by acreage dedication from a major producer in the Permian Basin. The Deadwood processing facility has a total capacity of 58 MMcf/d and total processing throughput that averaged 66,000 MMBtu/d for the year ended December 31, 2013. The Mesquite Terminal, which has 15,000 BBls/d of fractionation capacity, is located in Midland County and serves as a terminal for third party raw-make NGLs. The Partnership is also transloading crude oil and condensate at this facility.

Table of Contents

- *Gulf Coast Fractionators*. Midstream Holdings is entitled to receive the economic benefits and burdens of the 38.75% interest in Gulf Coast Fractionators held by Devon, with the remaining interests owned 22.50% by Phillips 66 and 38.75% by Targa Resources Partners. Gulf Coast Fractionators owns an NGL fractionator located on the Gulf Coast at Mont Belvieu, Texas. Phillips 66 is the operator of the fractionator. Gulf Coast Fractionators receives raw mix NGLs from customers, fractionates the raw mix and redelivers the finished products to the customers for a fee. The facility has a capacity of approximately 145 MBbls/d. For the year ended December 31, 2013, Gulf Coast Fractionators contributed $14.8 million of income on equity investments, on a pro forma basis giving effect to the business combination.

- *Gathering Systems*. Our gathering systems in Texas include approximately 3,725 miles of pipeline with total throughput of approximately 2,059,700 MMBtu/d and consist of the following:

- *Bridgeport rich gathering system*. This rich natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 2,440 miles of pipeline segments with approximately 145,000 horsepower of compression. A substantial majority of the natural gas gathered on the system is delivered to the Bridgeport processing facility. Devon is the largest customer on the Bridgeport rich gathering system with approximately 792,000 MMBtu/d of natural gas gathered for the year ended December 31, 2013, which represented approximately 92% of the total throughput on the system during such period. As described above, Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering and processing agreement pursuant to which Midstream Holdings will provide gathering services on the Bridgeport system, which includes a five-year minimum volume commitment from Devon of a combined 850 MMcf/d of natural gas delivered for gathering into the Bridgeport rich and Bridgeport lean gathering systems.

- *Bridgeport lean gathering system*. This lean natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 300 miles of pipeline segments with approximately 59,000 horsepower of compression. Natural gas gathered on this system is delivered to the Acacia transmission system and intrastate pipelines without processing. Devon is the largest customer on the Bridgeport lean gathering system with approximately 256,600 MMBtu/d of natural gas gathered for the year ended December 31, 2013, which represented approximately 98% of the total throughput on the system during such period. As described above, Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering and processing agreement that covers gathering services on the Bridgeport system.

- *East Johnson County gathering system*. This natural gas gathering system, which is owned by Midstream Holdings, consists of approximately 270 miles of pipeline segments. Natural gas gathered on this system is delivered to intrastate pipelines without processing. Devon is the largest customer on the East Johnson County gathering system with approximately 220,200 MMBtu/d of natural gas gathered for the year ended December 31, 2013, which represented approximately 93% of the total throughput on the system during such period. Devon and Midstream Holdings have entered into a 10-year, fixed-fee gathering agreement pursuant to which Midstream Holdings will provide gathering services on the East Johnson County gathering system, which includes a five-year minimum volume commitment from Devon of 125 MMcf/d of natural gas delivered for gathering into the East Johnson County gathering system as well as annual rate escalators.

- *Silver Creek gathering systems*. The Partnership s Silver Creek gathering systems includes two gathering systems. The Partnership s north Texas gathering system, which we refer to as NTG, consists of approximately 680 miles of gathering lines with approximately 112,874 horsepower of compression and had an average throughput of approximately 690,000 MMBtu/d for the year ended December 31, 2013. The Denton system consists of approximately 35 miles of gathering lines and had an average throughput of approximately 10,000 MMBtu/d for the year ended December 31, 2013.

- *Howard Energy Partners*. HEP owns and operates over 500 miles of pipeline and a 200 MMcf/d processing plant, serving production from the Eagle Ford, Escondido, Olmos, Pearsall and other formations in south Texas and pursues a growth strategy focused on the needs of south Texas producers. Howard s system has 145 MMcf/d of amine treating capacity and more than 9,000 horsepower of compression. In 2011 and 2012, the Partnership made capital contributions totaling $87.3 million to HEP in exchange for an individual ownership interest in HEP. As of December 31, 2013, the Partnership owned a 30.6% interest in HEP and accounted for this investment under the equity method of accounting. The Partnership includes its equity investment in HEP in its corporate segment. In December 2013, Alinda Capital Partners acquired a 59% capital interest in HEP from Quanta Capital Solutions and GE Energy Financial Services. The Partnership contributed an additional $30.6 million to HEP during the year ended December 31, 2013 to fund the Partnership s 30.6% share of HEP s expansion costs. The Partnership also received cash distributions totaling $17.5 million from HEP during the year ended December 31, 2013.

Oklahoma Assets. Our Oklahoma assets consist of processing facilities with a total processing capacity of approximately 550 MMcf/d, gathering systems with total capacity of approximately 605 MMcf/d and a crude oil and condensate stabilization facility. All of the systems and other assets comprising our Oklahoma assets are owned by Midstream Holdings, in which we own a 50% interest and the Partnership holds the remaining 50% interest.

- *Cana system*. Our Cana gathering and processing system is located in the Cana-Woodford Shale in West Central Oklahoma and consists of the following:

- *Cana processing facilities*. Our Cana processing facilities include a multi-train 350 MMcf/d cryogenic processing plant and a crude oil and condensate stabilization facility. For the year ended December 31, 2013,

Table of Contents

throughput volumes at the Cana processing facility averaged 278,700 MMBtu/d. The residue natural gas from the Cana processing facility is delivered to Enable Midstream Partners and ONEOK Partners. Devon is the only customer of the Cana processing facilities and has entered into a 10-year, fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide processing services for natural gas delivered by Devon to the Cana processing facility. This contractual arrangement includes a five-year minimum volume commitment from Devon of 330 MMcf/d of natural gas delivered to the processing facility as well as annual rate escalators.

- *Cana gathering system*. Our Cana gathering system includes an approximately 410-mile gathering system with approximately 92,500 horsepower of compression. For the year ended December 31, 2013, the Cana system gathered approximately 320,700 MMBtu/d of gas. Devon is the only customer of the Cana gathering system and, as described above, has entered into a 10-year, fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide gathering services on the Cana gathering system and that includes a five-year minimum volume commitment from Devon of 330 MMcf/d of natural gas delivered for gathering into the Cana gathering system.

- *Northridge system*. Our Cana gathering and processing system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma and consists of the following:

- *Northridge processing plant*. Our Northridge processing plant has 200 MMcf/d of processing capacity. For the year ended December 31, 2013, throughput volumes at the Northridge processing facility averaged 121,000 MMBtu/d. The residue natural gas from the Northridge processing facility is delivered to Centerpoint, Enable Midstream Partners and MarkWest. Devon is the largest customer of the Northridge processing facility with approximately 63,900 MMBtu/d of natural gas processed for the year ended December 31, 2013, which represented approximately 53% of the total volumes processed at the facility during such period. Devon has entered into a 10-year fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide processing services for natural gas delivered by Devon to the Northridge processing facility. This contractual arrangement includes a five-year minimum volume commitment of 40 MMcf/d of natural gas delivered to the Northridge processing facility as well as annual rate escalators.

- *Northridge gathering system*. Our Northridge gathering system includes an approximate 140-mile gathering system with approximately 17,900 horsepower of compression. For the year ended December 31, 2013, the Northridge system gathered 69,200 MMBtu/d of gas. Northridge gathered volumes exclude approximately 40 MMcf/d delivered by third parties directly to the processing facility. Devon is the only customer on the Northridge gathering system and, as described above, has entered into a 10-year fixed-fee gathering and processing agreement with Midstream Holdings pursuant to which Midstream Holdings will provide gathering services on the Northridge gathering system. This contract includes a five-year minimum volume commitment from Devon of 40 MMcf/d of natural gas delivered for gathering into the Northridge gathering system.

Louisiana Assets. Our Louisiana assets are owned by the Partnership and consist of transmission pipelines with a capacity of approximately 2.0 Bcf/d, processing facilities with a total processing capacity of approximately 1.7 Bcf/d and gathering systems with total capacity of approximately 510 MMcf/d.

- *LIG Assets*. The LIG system includes gathering and transmission systems with total capacity of approximately 2.0 Bcf/d, processing facilities with a total processing capacity of approximately 335 MMcf/d and fractionation facilities with total capacity of 10,800

Bbls/d.

- The LIG gathering and transmission pipeline system is comprised of the 1,125-mile southern system, which has a capacity in excess of 1.5 Bcf/d and approximately 31,318 horsepower of compression, and the 800-mile northern system, which has a capacity of 465 MMcf/d and approximately 52,060 horsepower of compression. The south system has access to both rich and lean gas supplies from onshore production in south central and southeast Louisiana. LIG has a variety of transportation and industrial sales customers in the south, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans. In the north, the LIG system serves the natural gas fields south of Shreveport, Louisiana and extends into the Haynesville Shale gas play in north Louisiana. The Partnership s north Louisiana system is connected to its south Louisiana system and has the capacity to move approximately 145 MMcf/d of gas to our markets in the south. The Partnership s LIG gathering system had an average throughput of approximately 473,000 MMbtu/d for the year ended December 31, 2013.

- The south system also includes two operating, on-system processing plants, the Partnership s Gibson and Plaquemine plants, with 110 MMcf/d and 225 MMcf/d of processing capacity, respectively. For the year ended December 31, 2013, throughput volumes on the LIG processing system averaged 255,000 MMBtu/d of natural gas.

- The Plaquemine plant also has a fractionation capacity of 10,800 Bbls/d of raw-make NGL products, and total volume for fractionated liquids at Plaquemine averaged approximately 4,800 Bbls/d for the year ended December 31, 2013.

Table of Contents

• *South Louisiana NGL and Processing Assets.* The Partnership s south Louisiana NGL and natural gas processing assets include approximately 570 miles of liquids transport lines, processing and fractionation capabilities and underground storage.

• *Cajun-Sibon Pipeline System.* Currently, the Cajun-Sibon pipeline system consists of approximately 570 miles of raw make NGL pipelines with a current system capacity of approximately 70,000 Bbls/d. The pipelines transport unfractionated NGLs, referred to as raw make, from areas such as the Liberty, Texas interconnects near Mont Belvieu and from the Partnership s Eunice and Pelican processing plants in south Louisiana to either the Riverside or Eunice fractionators or to third party fractionators when necessary.

• *Processing Facilities*. The Partnership s processing facilities in south Louisiana include three gas processing plants with total processing throughput that averaged 399,000 MMBtu/d for the year ended December 31, 2013 and two fractionation facilities that averaged 27,300 Bbls/d for the year ended December 31, 2013.

• *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. For the year ended December 31, 2013, the plant processed approximately 334,000 MMBtu/d of natural gas. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline. This plant has an interconnection with the LIG pipeline allowing us to process natural gas from the LIG system at our Pelican plant when markets are favorable.

• *Blue Water Gas Processing Plant.* The Partnership owns a 64.29% interest in the Blue Water gas processing plant and operates the plant. The Blue Water plant is located in Crowley, Louisiana and is connected to the Blue Water pipeline system. The plant has a net capacity to the Partnership s interest of approximately 300 MMcf/d. For the year ended December 31, 2013, throughput volumes at the Blue Water gas processing plant averaged 12,600 MMBtu/d of natural gas. The plant is not expected to operate in the future unless fractionation spreads are favorable and volumes are sufficient to run the plant.

• *Eunice Processing Plant.* The Eunice processing plant is located in south central Louisiana, has a capacity of 475 MMcf/d of natural gas and processed approximately 31,200 MMBtu/d of natural gas for the year ended December 31, 2013. In August 2013, the Partnership shut down the Eunice processing plant due to adverse economics driven by low NGL prices and low processing volumes, which the Partnership does not see improving in the near future based on forecasted prices.

• *Eunice Fractionation Facility.* The Eunice fractionation facility is located in south central Louisiana and was restarted in 2011 to take advantage of the activity around liquids rich shale-plays, including the Eagle Ford, Permian, Granite Wash, Marcellus and Utica plays. The Eunice fractionation facility has a capacity of 55,000 Bbls/d of liquid products, including ethane, propane, iso-butane, normal butane and natural gasoline, and is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility. The plant fractionated 5,100 Bbls/d of liquids during 2013.

• *Riverside Fractionation Facility.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of approximately 28,000 Bbls/d of liquids delivered by the Cajun-Sibon pipeline system from the Eunice, Pelican and Blue Water processing plants or by third-party truck and rail assets. The Riverside facility has above-ground storage capacity of approximately 233,000 Bbls. The loading/unloading facility has the capacity to transload 15,000 Bbls/d of crude oil and condensate from rail cars to barges. Total volumes for fractionated liquids at Riverside averaged 22,200 Bbls/d for the year ended December 31, 2013.

- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of 3.1 million barrels of underground storage comprised of two existing caverns. The caverns are currently operated in propane and butane service, and space is leased to customers for a fee.

Ohio River Valley Assets. The Partnership s Ohio River Valley operations are an integrated network of assets comprised of a 4,500-barrel-per-hour crude oil and condensate barge loading terminal on the Ohio River, a 20-spot crude oil and condensate rail loading terminal on the Ohio Central Railroad network and approximately 200 miles of crude oil and condensate pipelines in Ohio and West Virginia. The assets also include 500,000 barrels of above ground storage and a trucking fleet of approximately 100 vehicles comprised of both semi and straight trucks with a current capacity of 25,000 Bbls/d. Total crude oil and condensate handled averaged approximately 11,000 Bbls/d for the year ended December 31, 2013. The Partnership has eight existing brine disposal wells with an injection capacity of approximately 10,000 Bbls/d and an average disposal rate of 7,000 Bbls/d for the year ended December 31, 2013. The Partnership currently holds one additional well permit in Ohio. Additionally, the assets held by E2, in which our wholly-owned subsidiary owned approximately 93.7% of E2 Energy Services, LLC and approximately 92.5% of E2 Appalachian Compression, LLC, consist of three gas gathering compressor stations and condensate stabilization assets located in Noble and Monroe counties in the southern portion of the Utica Shale play in Ohio. The compressor stations have a total capacity of 340 MMcf/d and 44,000 horsepower of compression with condensate handling capacity of 16,000 Bbls/d. Commercial operations of one of the facilities, which we refer to as Upper Hill, commenced during January 2014. None of these facilities were in service as of December 31, 2013.

Table of Contents

Industry Overview

The following diagram illustrates the gathering, processing, fractionation and transmission process.

The midstream industry is the link between the exploration and production of natural gas and crude oil and condensate and the delivery of its components to end-user markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas and crude oil and condensate producing wells.

Natural gas gathering. The natural gas gathering process follows the drilling of wells into gas-bearing rock formations. After a well has been completed, it is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression and treating systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

Compression. Gathering systems are operated at pressures that will maximize the total natural gas throughput from all connected wells. Because wells produce gas at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver gas into a higher-pressure downstream pipeline. The remaining natural gas in the ground will not be produced if field compression is not installed because the gas will be unable to overcome the higher gathering system pressure. In contrast, a declining well can continue delivering natural gas if the field compression is installed.

Natural gas processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and CO_2, sulfur compounds, nitrogen or helium. Natural gas produced by a well may not be suitable for long-haul pipeline transportation or commercial use and may need to be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems mostly consists of methane and ethane, and moisture and other contaminants have been removed so there are negligible amounts of them in the gas stream. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream and the removal of contaminants.

Table of Contents

NGL fractionation. NGLs are separated into individual, more valuable components during the fractionation process. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized crude oil and condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutene through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

Natural gas transmission. Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, processing plants and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

Crude oil and condensate transmission. Crude oil and condensate are transported by pipelines, barges, rail cars and tank trucks. The method of transportation used depends on, among other things, the resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of product being transported.

Brine gathering and disposal services. Typically, shale wells produce significant amounts of water that, in most cases, require disposal. Produced water and frac-flowback is hauled via truck transport or is pumped through pipelines from its origin at the oilfield tank battery or drilling pad to the disposal location. Once the water reaches the delivery disposal location, water is processed and filtered to remove impurities and injection wells place fluids underground for storage and disposal.

Crude oil and condensate terminals. Crude oil and condensate rail terminals are an integral part of ensuring the movement of new crude oil and condensate production from the developing shale plays in the United States and Canada. In general, the crude oil and condensate rail loading terminals are used to load rail cars and transport the commodity out of developing basins into market rich areas of the country where crude oil and condensate rail unloading terminals are used to unload rail cars and store crude oil and condensate volumes for third parties until the crude oil and condensate is redelivered to premium markets via pipelines, trucks or rail to delivery points.

Balancing Supply and Demand

When the Partnership purchases natural gas, crude oil and condensate, we establish a margin normally by selling it for physical delivery to third-party users. The Partnership can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the New York Mercantile Exchange (the NYMEX) related to its natural gas purchases. Through these transactions, the Partnership seeks to maintain a position that is balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. The Partnership s policy is not to acquire and hold natural gas futures contracts or derivative products for the purpose of speculating on price changes.

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas, NGLs, crude oil and condensate is highly competitive. The Midstream Entities face strong competition in obtaining natural gas, NGLs, crude oil and condensate supplies and in the marketing and transportation of natural gas, NGLs, crude oil and condensate, as applicable. Their competitors include major integrated and independent exploration and production crude oil and condensate companies, natural gas producers, interstate and intrastate pipelines, other natural gas and crude oil and condensate gatherers and natural gas processors. Competition for natural gas and crude oil and condensate supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. As a result of the relationship between Devon and Midstream Holdings, the Midstream Entities will not compete for the portion of Devon s existing operations subject to existing acreage dedication and for which Midstream Holdings will provide midstream services. For areas where acreage is not dedicated to Midstream Holdings, the Midstream Entities will compete with similar enterprises in providing additional gathering and processing services in its respective areas of operation, which may offer more services or have strong financial resources and access to larger natural gas, NGLs, crude oil and condensate supplies than they do. Competition varies in different geographic areas.

In marketing natural gas and NGLs, the Midstream Entities have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas producers, gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly and through affiliates in marketing activities that compete with their marketing operations.

The Midstream Entities face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition increases the cost to acquire existing facilities or businesses and results in fewer commitments and lower returns for new pipelines or other development projects. The Midstream Entities competitors may have greater financial resources than they possess or may be willing to accept lower returns or greater risks. Competition differs by region and by the nature of the business or the project involved.

Natural Gas, NGL, Crude Oil and Condensate Supply

The Midstream Entities gathering and transmission pipelines have connections with major intrastate and interstate pipelines, which they believe have ample natural gas and NGLs supplies in excess of the volumes required for the operation of these systems. The Partnership s Ohio River Valley pipeline, terminals, trucks and storage facilities are strategically located in crude oil and condensate producing regions. The Midstream Entities evaluate well and reservoir data that is either publicly available or furnished by producers or other service providers in connection with the construction and acquisition of their gathering systems and assets to determine the availability of natural gas, NGLs, crude oil and condensate supply for their

Table of Contents

systems and assets and/or obtain a minimum volume commitment from the producer that results in a rate of return on investment. The Midstream Entities do not routinely obtain independent evaluations of reserves dedicated to their systems and assets due to the cost and relatively limited benefit of such evaluations. Accordingly, the Midstream Entities do not have estimates of total reserves dedicated to their systems and assets or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

The Midstream Entities are diligent in attempting to ensure that they issue credit to only credit-worthy customers. However, the purchase and resale of crude oil and condensate, gas and other products exposes them to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to their overall profitability.

During the year ended December 31, 2013, Devon represented 24.9% of our consolidated revenues, on a pro forma basis. No other customer represented greater than 10.0% of our revenue. Midstream Holdings operations are dependent on the volume of natural gas that Devon provides to it under commercial agreements, which constitutes substantially all of their natural gas supply, and the Midstream Entities do not expect to materially increase volumes from third-party producers in the near term. Accordingly, for the foreseeable future, we expect their profitability to be substantially dependent on Devon.

Regulation

Interstate Natural Gas Pipelines Regulation. The Midstream Entities do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission (FERC), does not directly regulate our natural gas operations under the National Gas Act (NGA). However, FERC s regulation of interstate natural gas pipelines influences certain aspects of their business and the market for the Midstream Entities products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;

- maximum rates payable for certain services; and
- the initiation and discontinuation of services.

The Partnership and Midstream Holdings transport gas in interstate commerce. The rates, terms and conditions of service under which the Partnership and Midstream Holdings transport natural gas in their pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act (NGPA). The maximum rates for services provided under Section 311 of the NGPA may not exceed a fair and equitable rate, as defined in the NGPA. The rates are generally subject to review every three years by FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations, the inability to achieve adequate returns on investments in new facilities and the deterrence of future investment or growth of the regulated facilities.

Interstate Liquids Pipelines Regulation. The Partnership owns liquids transportation, storage and other assets in the Ohio River Valley, including certain assets providing common carrier interstate service subject to regulation by FERC under the Interstate Commerce Act (ICA), the Energy Policy Act of 1992 and related rules and orders. The Partnership s Cajun-Sibon NGL pipeline became subject to FERC regulation as a result of the Partnership s Phase I expansion, which went into operation in November 2013. The expansion is subject to regulation by FERC as a common carrier under the ICA, the Energy Policy Act of 1992 and related rules and orders.

FERC regulation requires that interstate liquids pipeline rates and terms and conditions of service, including rates for transportation of crude oil, condensate and NGLs, be filed with FERC and that these rates and terms and conditions of service be just and reasonable and not unduly discriminatory or unduly preferential.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC s regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-services approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit the Partnership s ability to set rates based on its costs or could order the Partnership to reduce its rates and could require the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change the Partnership s terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

Table of Contents

As the Partnership acquires, constructs and operates new liquids assets and expands its liquids transportation business, the classification and regulation of its liquids transportation services are subject to ongoing assessment and change based on the services the Partnership provides and determinations by FERC and the courts. Such changes may subject additional services the Partnership provides to regulation by FERC.

Intrastate Natural Gas Pipeline Regulation. The Midstream Entities intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Intrastate NGL Pipeline Regulation. Intrastate NGL and other petroleum pipelines are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases.

Gathering Pipeline Regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. The Midstream Entities own a number of natural gas pipelines that they believe meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

The Midstream Entities are subject to some state ratable take and common purchaser statutes. 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.

Intrastate Natural Gas Storage Regulation. The storage field s injection and withdrawal wells used in association with the Acacia system, along with water disposal wells located at the Bridgeport processing facility, are under the jurisdiction of the Texas Railroad Commission (TRRC). Regulatory requirements for these wells involve monthly and annual reporting of the natural gas and water disposal volumes associated with the operation of such wells, respectively. Results of periodic mechanical integrity tests run on these wells must also be reported to the TRRC.

Sales of Natural Gas and NGLs. The price at which the Midstream Entities sell natural gas and NGLs currently are not subject to federal regulation and, for the most part, are not subject to state regulation. The Midstream Entities natural gas and NGL sales 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 and NGL industries, most notably interstate natural gas transmission companies and NGL pipeline companies that remain subject to FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes on the Midstream Entities natural gas and NGL marketing operations, but we do not believe that the Midstream Entities will be affected by any such FERC action in a manner that is materially different from the natural gas and NGL marketers with whom they compete.

Environmental Matters

General. The Midstream Entities operations involve processing and pipeline services for delivery of hydrocarbons (natural gas, NGLs, crude oil and condensates) from point-of-origin at oil and gas wellheads operated by their suppliers to the Midstream Entities end-use market customers. The Midstream Entities facilities include natural gas processing and fractionation plants, brine disposal wells, pipelines and associated facilities, fractionation and storage units for NGLs, and transportation and delivery of petroleum. As with all companies in the Midstream Entities industrial sector, the Midstream Entities operations are subject to stringent and complex federal, state and local laws and regulations relating to release of hazardous substances or solid wastes into the environment or otherwise relating to protection of the environment. Compliance with existing and anticipated environmental laws and regulations increases the Midstream Entities overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities, as well as capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures, and obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of temporary or permanent injunctions or construction or operation bans or delays. As part of the regular evaluation of the Midstream Entities operations, they routinely review and update governmental approvals as necessary.

The continuing trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts the Midstream Entities currently

Table of Contents

anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with possible future operations, and we cannot assure you that we will not incur significant costs and liabilities, including those relating to claims for damage to property and persons as a result of any such upsets, releases or spills. In the event of future increases in environmental costs, the Midstream Entities may be unable to pass on those cost increases to their customers. A discharge of hazardous substances or solid wastes into the environment could, to the extent losses related to the event are not insured, subject the Midstream Entities to substantial expense, including both the cost to comply with applicable laws and regulations and to pay fines or penalties that may be assessed and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to natural resources or property. The Midstream Entities attempt to anticipate future regulatory requirements that might be imposed and plan accordingly to comply with changing environmental laws and regulations and to minimize costs with respect to more stringent future laws and regulations or more rigorous enforcement of existing laws and regulations.

Hazardous Substances and Solid Waste. Environmental laws and regulations that relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water and/or include measures to prevent and control pollution may pose the highest potential cost to our industry sector. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes and may require investigatory and corrective actions at facilities where such waste may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the federal Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to a release of a hazardous substance into the environment. Potentially liable persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at an off-site location, such as a landfill. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources. CERCLA also authorizes the U.S. Environmental Protection Agency (EPA) and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek recovery of costs they incur from the potentially 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 solid wastes released into the environment. Although petroleum, natural gas and NGLs are excluded from CERCLA s definition of a hazardous substance, in the course of ordinary operations, the Midstream Entities may generate wastes that may fall within the definition of a hazardous substance. In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, the Midstream Entities may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such substances have been disposed. The Midstream Entities have not received any notification that they may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state law.

The Midstream Entities also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and/or comparable state statutes. From time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil, condensate and natural gas wastes. Moreover, it is possible that some wastes generated by the Midstream Entities that are currently exempted from the definition of hazardous waste may in the future be designated as hazardous wastes, resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Changes in applicable laws or regulations may result in an increase in the Midstream Entities capital expenditures or plant operating expenses or otherwise impose limits or restrictions on our production and operations.

The Midstream Entities currently own or lease, have in the past owned or leased, and in the future may own or lease, properties that have been used over the years for brine disposal operations, crude oil and condensate transportation, natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes may have been disposed of on or under various properties owned, leased or operated by the Midstream Entities during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whose operations and hydrocarbon and waste management practices the Midstream Entities had no control. These properties and wastes disposed thereon may be subject to the Safe Drinking Water Act, CERCLA, RCRA and analogous state laws. Under these laws, the Midstream Entities could be required, alone or in participation with others, to remove or remediate previously disposed wastes or property contamination, if present, including groundwater contamination, or to take action to prevent future contamination.

Air Emissions. The Midstream Entities current and future operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including the Midstream Entities facilities, and impose various controls together with monitoring and reporting requirements. Pursuant to these laws and regulations, the Midstream Entities may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. The Midstream Entities likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission-related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on the Midstream Entities financial condition or operating results, and the requirements are not expected to be more burdensome to the Midstream Entities than to any similarly situated company.

Table of Contents

In addition, the EPA included Wise County in its January 2012 revision to the Dallas-Ft. Worth ozone nonattainment area for the 2008 revised ozone national ambient air quality standard (NAAQS). As a result of this designation, new major sources, meaning sources that emit greater than 100 tons/year of nitrogen oxides (NOx) and volatile organic compounds (VOCs), as well as major modifications of existing facilities resulting in net emissions increases of greater than 40 tons/year of NOx or VOCs, are subject to more stringent new source review (NSR) pre-construction permitting requirements than they would be in an area that is in attainment with the 2008 ozone NAAQS. NSR pre-construction permits can take twelve to eighteen months to obtain and require the permit applicant to offset the proposed emission increases with reductions elsewhere at 1.15 to 1 ratio. Devon, Texas industry trade groups and the State of Texas filed petitions for reconsideration with EPA and a petition for review in the U.S. D.C. Circuit Court of Appeals challenging the nonattainment designation of Wise County under the 2008 ozone NAAQS. The appeal remains pending.

On April 17, 2012, the EPA approved final rules under the Clean Air Act that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. For new or reworked hydraulically-fractured gas wells, the rules require the control of emissions through flaring or reduced emission (or green) completions until 2015, when the rules require the use of green completions by all such wells except wildcat (exploratory) and delineation gas wells and low reservoir pressure non-wildcat and non-delineation gas wells. The rules also establish specific new requirements regarding emissions from wet seal and reciprocating compressors at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2012, and from pneumatic controllers and storage vessels at production facilities, gathering systems, boosting facilities and onshore natural gas processing plants, effective October 15, 2013. In addition, the rules revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring the monitoring of connectors, pumps, pressure relief devices and open-ended lines, effective October 15, 2012. These rules required a number of modifications to our assets and operations.

In October 2012, several challenges to the EPA s April 17, 2012 rules were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The case remains in abeyance. EPA issued a final rule revising certain aspects of the rules on August 5, 2013 and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such proceedings, the rules may be further modified or rescinded or the EPA may issue new rules. The costs of compliance with any modified or newly issued rules cannot be predicted. Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel the agency to make a determination whether standards of performance limiting methane emissions from the oil and gas sector are appropriate, which was not addressed in the EPA rule took effect on October 15, 2012. The notice of intent also requested that the EPA issue emission guidelines for the control of methane emissions from existing oil and gas sources. Depending on whether such rules are promulgated and the applicability and restrictions in any promulgated rule, compliance with such rules could result in additional costs, including increased capital expenditures and operating costs for us and for other companies in our industry. While the Midstream Entities are not able at this time to estimate such additional costs, as is the case with similarly situated entities in the industry, they could be significant for the Midstream Entities. Compliance with such rules, as well as any new state rules, may also make it more difficult for the Midstream Entities suppliers and customers to operate, thereby reducing the volume of natural gas transported through the Midstream Entities pipelines, which may adversely affect their business.

Climate Change. In December 2009, the EPA determined that emissions of certain gases, common referred to as greenhouse gases, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under existing provisions of the federal Clean Air Act, that establish Prevention of Significant Deterioration (PSD) pre construction permits, and Title V operating permits for greenhouse gas emissions from certain large stationary sources. Under these regulations, facilities required to obtain PSD permits must meet best available control technology standards for their greenhouse gas emissions established by the states or, in some cases, by the EPA on a case by case basis. The EPA has also adopted rules requiring the monitoring and reporting of greenhouse gas emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities.

Because regulation of greenhouse gas emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments in greenhouse gas initiatives may affect the Midstream Entities and other companies operating in the oil and gas industry. In addition to these developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against greenhouse gas emissions sources, which may increase the Midstream Entities litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with greenhouse gas emissions, we cannot predict the financial impact of related developments on the Midstream Entities.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which the Midstream Entities conduct business could adversely affect the availability of, or demand for, the products the Midstream Entities store, transport and process, and, depending on the particular program adopted, could increase the costs of the Midstream Entities operations, including costs to operate and maintain their facilities, install new emission controls on their facilities, acquire allowances to authorize their greenhouse gas emissions, pay any taxes related to their greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. The Midstream Entities may be unable to recover any such lost revenues or increased costs in the rates the Midstream Entities charge their customers, and any such recovery may depend on events beyond the Midstream Entities control, including the outcome of future rate proceedings before FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in the Midstream Entities revenues or increases in their expenses as a result of climate control initiatives could have adverse effects on the Midstream Entities business, financial position, results of operations and prospects.

Table of Contents

Some scientific studies on climate change suggest that adverse weather events may become stronger or more frequent in the future in certain of the areas in which the Midstream Entities operate, although the scientific studies are not unanimous. Due to their location, the Partnership s operations along the Gulf Coast are vulnerable to operational and structural damages resulting from hurricanes and other severe weather systems, while inland operations include areas subject to tornadoes. The Midstream Entities insurance may not cover all associated losses. The Midstream Entities are taking steps to mitigate physical risks from storms, but no assurance can be given that future storms will not have a material adverse effect on their business.

Hydraulic Fracturing and Wastewater. The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including NGL related wastes, into state waters or waters of the United States. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System (NPDES), and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that the Midstream Entities are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder and that continued compliance with such existing permit conditions will not have a material effect on the Midstream Entities results of operations.

The Partnership operates brine disposal wells that are regulated as Class II wells under the federal Safe Drinking Water Act (SDWA). The SDWA imposes requirements on owners and operators of Class II wells through the EPA s Underground Injection Control program, including construction, operating, monitoring and testing, reporting and closure requirements. The Partnership s brine disposal wells are also subject to comparable state laws and regulations, which in some cases are more stringent than requirements under the federal SDWA. Compliance with current and future laws and regulations regarding the Partnership s brine disposal wells may impose substantial costs and restrictions on our brine disposal operations, as well as adversely affect demand for the Partnership s brine disposal services. State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on the Partnership s brine disposal operations.

It is common for the Midstream Entities customers or suppliers to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by oil and gas producers. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states and localities have been initiated to require or make more stringent the permitting and other regulatory requirements for hydraulic fracturing operations. There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. Additional regulatory burdens in the future, whether federal, state or local, could increase the cost of or restrict the ability of the Midstream Entities customers or suppliers to perform hydraulic fracturing. As a result, any increased federal, state or local regulation could reduce the volumes of natural gas that the Midstream Entities customers move through their gathering systems which would materially adversely affect the Midstream Entities revenues and results of operations.

Employee Safety. The Midstream Entities are subject to the requirements of the Occupational Safety and Health Act (OSHA), and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that the Midstream Entities operations are in substantial compliance with the OSHA requirements including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Pipeline Safety Regulations. The Midstream Entities pipelines are subject to regulation by the U.S. Department of Transportation (DOT). DOT s Pipeline Hazardous Material Safety Administration (PHMSA), acting through the Office of Pipeline Safety (OPS), administers the national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of pipeline facilities. The main bodies of safety regulations that cover the Midstream Entities operations are set forth at 49 CFR, Parts 192 (covering pipelines that transport natural gas) and 195 (pipelines that transport crude oil and condensate, carbon dioxide, NGL and petroleum products). In addition to recordkeeping and reporting requirements, amendments to 49 CFR Part 192 and 195 created the Pipeline Integrity Management in High Consequence Areas (PIM) requiring operators of transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment

Table of Contents

techniques. In January 2012, the President signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 which increases potential penalties for pipeline safety violations, gives new rulemaking authority to DOT with respect to shut-off valves on transmission pipeline facilities constructed or entirely replaced after the rule is promulgated, requires DOT to revise incident notification guidance and imposes new records requirements on pipeline owners and operators. This legislation also requires DOT to study and report to Congress on other areas of pipeline safety, including expanding the reach of the integrity management regulations beyond high consequences areas, but restricts DOT from promulgating expanded integrity management rules during the review period and for a period following submission of its report to Congress unless the rulemaking is needed to address a present condition that poses a risk to public safety, property or the environment. PHMSA issued a final rule effective October 25, 2013 that implemented aspects of the new legislation. Among other things, the final rule increases the maximum civil penalties for violations of pipeline safety statutes or regulations, broadens PHMSA s authority to submit information requests, and provides additional detail regarding PHMSA s corrective action authority. Additionally, PHMSA issued an Advisory Bulletin in May 2012, which advised pipeline operators of anticipated changes in annual reporting requirements and that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures could significantly increase the Midstream Entities costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity on the Midstream Entities pipelines. A December 2012 PHMSA Advisory Bulletin provides further clarity on the reporting requirements of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, describing a general requirement that pipeline owners or operators report an exceedance of the maximum allowable operating pressure or allowable build-up for pressure-limiting or control devices within five days of the date that the exceedance occurs. At the state level, several states have passed legislation or promulgated rulemaking dealing with pipeline safety. We believe that the Midstream Entities pipeline operations are in substantial compliance with applicable PHMSA and state requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on the Midstream Entities results of operations or financial positions.

Bayou Corne Sinkhole Incident. The Partnership owns and operates a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of these pipelines and our underground storage reservoirs located in Napoleonville, Louisiana.

Following the formation of the sinkhole, the Partnership and other pipeline operators in the area promptly undertook steps to depressurize and shut down their pipelines in the affected area. In particular, the Partnership took a section of its 36-inch diameter natural gas pipeline out of service. The Partnership s pipeline remains out of service, which has partially interrupted service to certain markets including the Mississippi River, but the Partnership worked with its customers to secure alternative natural gas supplies to minimize disruptions. In addition, the Partnership has identified a reroute for this pipeline outside of the affected areas. The Partnership is currently in the initial phase of constructing the replacement pipeline in its rerouted location and anticipate such construction will be completed during first half of 2014. The Partnership also implemented additional inspection and operational measures at its nearby underground facility. The damage to the Partnership s business, including costs and loss of business, has been considerable.

The cause and full consequences of this sinkhole and the conditions giving rise thereto remain uncertain. In addition, any restrictions imposed by governmental agencies could negatively impact our assets. The Partnership is assessing the potential for recovering its losses from responsible parties and is seeking recovery from its insurers. The Partnership s insurers, however, have denied its insurance claim for coverage and filed a declaratory judgment asking a court to determine that the Partnership s insurance policy does not cover this damage. The Partnership has sued its insurers for breach of contract due to the insurers refusal to pay the Partnership s insurance claim for this damage. We cannot assure you that the Partnership will be able to fully recover its losses through insurance recovery or claims against responsible parties.

Office Facilities

The Midstream Entities occupy approximately 108,500 square feet of space at our executive offices in Dallas, Texas under a lease expiring in August 2019, approximately 25,100 square feet of office space for the Partnership s Louisiana operations in Houston, Texas with lease terms expiring in April 2023 and approximately 9,000 square feet of office space in Lafayette, Louisiana with lease terms expiring in January 2023. In connection with the consummation of the business combination, the Partnership entered into three office lease agreements with a wholly-owned subsidiary of Devon pursuant to which we will occupy approximately 12,500 square feet, 2,200 square feet and 4,700 square feet at Devon s Bridgeport, Oklahoma City and Cresson office buildings, respectively. Each lease is scheduled to expire in March 2016.

Employees

As of March 24, 2014, the Partnership (through its subsidiaries) employed approximately 1,100 full-time employees. Approximately 245 of the Partnership s employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. The Partnership is not party to any collective bargaining agreements and it has not had any significant labor disputes in the past. The Partnership believes that it has good relations with its employees.

Item 1A. ***Risk Factors***

The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are

Table of Contents

described below, may also impair our business operations. If any of the following risks occur, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to pay distributions to our unitholders and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations included herein.

Risks Related to the Company

Our cash flow consists almost exclusively of distributions from EnLink Midstream Partners, LP and EnLink Midstream Holdings, LP.

Currently, our only cash-generating assets are our partnership interests in EnLink Midstream Partners, LP and EnLink Midstream Holdings, LP, although we expect our E2 investments to begin to generate cash flow for distribution as its plants commence operations during 2014. Our cash flow is therefore completely dependent upon the ability of the Partnership and Midstream Holdings to make distributions to their partners. Accordingly, you should read and consider the risk factors described under the caption Risks Inherent in the Midstream Entities Business. The amount of cash that the Partnership and Midstream Holdings can distribute to their partners, including us, each quarter principally depends upon the amount of cash it generates from their operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in their gathering and transmission pipelines;
- the level of the Midstream Entities processing operations;
- the fees the Midstream Entities charge and the margins they realizes for their services;
- the prices of, levels of production of and demand for oil and natural gas;
- the volume of natural gas the Midstream Entities gather, compress, process, transport and sell, the volume of NGLs the Midstream Entities process or fractionate and sell, the volume of crude oil the Midstream Entities handle at their crude terminals, the volume of crude oil and condensate the Midstream Entities gather, transport, purchase and sell and the volumes of brine the Partnership disposes;
- the relationship between natural gas and NGL prices; and

- the Midstream Entities level of operating costs.

In addition, the actual amount of cash the Partnership and Midstream Holdings will have available for distribution will depend on other factors, some of which are beyond their control, including:

- the level of capital expenditures the Midstream Entities make;
- the cost of acquisitions, if any;
- the Partnership s debt service requirements;
- fluctuations in their working capital needs;
- the Partnership s ability to make working capital borrowings under its bank credit facility to pay distributions;
- prevailing economic conditions; and
- the amount of cash reserves established by their respective general partners in their sole discretion for the proper conduct of business.

Because of these factors, the Partnership and Midstream Holdings may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash the Partnership and Midstream Holdings have available for distribution depends primarily upon their cash flows, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership and Midstream Holdings may make cash distributions during periods when they record losses and may not make cash distributions during periods when it records net income.

Although we control the Partnership, the general partner owes fiduciary duties to the Partnership and the unitholders.

Table of Contents

Conflicts of interest exist and may arise in the future as a result of the relationship between us and our affiliates, including the General Partner, on the one hand, and the Partnership and its limited partners, on the other hand. The directors and officers of EnLink Midstream GP, LLC have fiduciary duties to manage the General Partner in a manner beneficial to us, its owner. At the same time, the General Partner has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and its limited partners. The board of directors of EnLink Midstream GP, LLC will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to the Partnership and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and the Partnership, on the other hand;
- the determination of the amount of cash to be distributed to the Partnership s partners and the amount of cash to be reserved for the future conduct of the Partnership s business;
- the determination whether to make borrowings under the Partnership s existing credit facility to pay distributions to partners; and
- any decision we make in the future to engage in activities in competition with the Partnership.

If the General Partner is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of the Partnership, its value, and therefore the value of our common units, could decline.

The General Partner may make expenditures on behalf of the Partnership for which it will seek reimbursement from the Partnership. In addition, under Delaware law, the General Partner, in its capacity as the General Partner of the Partnership, has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to the General Partner. To the extent the General Partner incurs obligations on behalf of the Partnership, it is entitled to be reimbursed or indemnified by the Partnership. In the event that the Partnership is unable or unwilling to reimburse or indemnify the General Partner, the General Partner may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of our common units.

If in the future we cease to manage and control the Partnership, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control the Partnership and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify our organizational structure or our contractual rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us and our affiliates, and adversely affect the price of our common units.

The terms of our credit facility may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

Our credit agreement contains, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. In addition, our credit facility requires us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under our credit facility. Upon the occurrence of such an event of default, all amounts outstanding under the credit facility could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If we are unable to repay the accelerated debt under our credit facility, the lenders could proceed against the collateral granted to them to secure that indebtedness. We have pledged the Partnership common units and the 100% membership interest in the General Partner that are indirectly held by us, along with our 100% equity interest in each of our wholly-owned subsidiaries and our 50% limited partner interest in Midstream Holdings as collateral under our credit facility. If indebtedness under our credit facility is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in our credit facility and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Certain events of default under the Partnership s credit facility, the occurrence of certain bankruptcy events affecting the Midstream Entities or our failure to continue to control the Partnership and Midstream Holdings could constitute an event of default under our credit facility.

Under the terms of our credit facility, certain events of default under the Partnership s credit facility could constitute an event of default under our credit facility. Additionally, certain events of default under our credit facility relate specifically to events relating to the Midstream Entities, including certain bankruptcy events affecting the Midstream Entities or any event that causes us to no longer indirectly control the Partnership or Midstream Holdings. Additionally, any default by the Partnership under the terms of its credit facility could limit its ability to make distributions to us.

Table of Contents

Risks Inherent in the Midstream Entities Business

Midstream Holdings is dependent on Devon for substantially all of the natural gas that it gathers, processes and transports. After the expiration of the five-year minimum volume commitments from Devon, a material decline in the volumes of natural gas that Midstream Holdings gathers, processes and transports for Devon could result in a material decline in the Midstream Entities operating results and cash available for distribution.

Midstream Holdings relies on Devon for substantially all of its natural gas supply. For the year ended December 31, 2013, Devon represented 24.9% of our consolidated revenues, on a pro forma basis. In order to minimize volumetric exposure, Midstream Holdings has received five-year minimum volume commitments from Devon at the Bridgeport processing facility, Bridgeport and East Johnson County gathering systems and the Cana and Northridge systems. After the expiration of these five-year minimum volume commitments, a material decline in the volume of natural gas that Midstream Holdings gathers and transports on its systems would result in a material decline in our combined total operating revenues and cash flow. In addition, Devon may determine in the future that drilling activity in areas of operation other than Midstream Holdings is strategically more attractive. A shift in Devon s focus away from Midstream Holdings areas of operation could result in reduced throughput on Midstream Holdings systems after the five-year minimum volume commitments expire and cause a material decline in our total operating revenues and cash flow.

Because the Midstream Entities are substantially dependent on Devon as their primary customer and through Devon s control of us and our control of the Partnership s general partner, any development that materially and adversely affects Devon s operations, financial condition or market reputation could have a material and adverse impact on the Midstream Entities and us. Material adverse changes at Devon could restrict our access to capital, make it more expensive to access the capital markets or increase the costs of our or the Partnership s borrowings.

The Midstream Entities are substantially dependent on Devon as their primary customer and through Devon s control of us and our control of the Partnership s general partner, and we expect the Midstream Entities to derive a substantial majority of their revenues from Devon for the foreseeable future. As a result, any event, whether in the Midstream Entities area of operations or otherwise, that adversely affects Devon s production, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect the Midstream Entities revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Devon, some of which are the following:

- potential changes in the supply of and demand for oil, natural gas and natural gas liquids (NGLs) and related products and services;

- risks relating to Devon s exploration and drilling programs, including potential environmental liabilities;

- adverse effects of governmental and environmental regulation; and

- general economic and financial market conditions.

Further, the Midstream Entities are subject to the risk of non-payment or non-performance by Devon, including with respect to Midstream Holdings gathering and processing agreements. We cannot predict the extent to which Devon s business would be impacted if conditions in the energy industry were to deteriorate, nor can we estimate the impact such conditions would have on Devon s ability to perform under Midstream Holdings gathering and processing agreements. Additionally, due to our relationship with Devon, our or the Partnership s ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairments to Devon s financial condition or adverse changes in its credit ratings. Any material limitations on our or the Partnership s ability to access capital as a result of such adverse changes at Devon could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Devon could negatively impact our or the Partnership s unit price, limiting our ability to raise capital through equity issuances or debt financing or our ability to engage in, expand or pursue our business activities and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Please see Item 1.A in Devon s Annual Report on Form 10-K for the year ended December 31, 2013 for a full discussion of the risks associated with Devon s business.

Due to the Midstream Entities lack of asset diversification, adverse developments in the Midstream Entities gathering, transmission, processing, crude oil, condensate, natural gas and NGL services businesses would reduce their ability to make distributions to us.

The Midstream Entities rely exclusively on the revenues generated from their gathering, transmission, processing, fractionation, crude oil, natural gas, condensate and NGL services businesses and as a result their financial condition depends upon prices of, and continued demand for, natural gas, NGLs and crude oil. Due to the Midstream Entities lack of asset diversification, an adverse development in one of these businesses may have a significant impact on the Midstream Entities financial condition and their ability to make distributions to us.

A significant portion of the Midstream Entities operations are located in the Barnett Shale, making the Midstream Entities vulnerable to risks associated with having revenue-producing operations concentrated in a limited number of geographic areas.

The Midstream Entities revenue-producing operations are geographically concentrated in the Barnett Shale, causing them to be disproportionally exposed to risks associated with regional factors. Specifically, the Midstream Entities operations in the Barnett Shale accounted for approximately 28.4% of our consolidated revenues on a pro forma basis for the year ended December 31, 2013. The concentration of the Midstream Entities operations in these regions also increases exposure to

Table of Contents

unexpected events that may occur in these regions such as natural disasters or labor difficulties. Any one of these events has the potential to have a relatively significant impact on the Midstream Entities operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development within originally anticipated time frames. Any of these risks could have a material adverse effect on the Midstream Entities financial condition and results of operations.

The Midstream Entities must continually compete for crude oil, condensate and natural gas supplies, and any decrease in supplies of such commodities could adversely affect the Midstream Entities financial condition and results of operations.

In order to maintain or increase throughput levels in the Midstream Entities natural gas gathering systems and asset utilization rates at their processing plants and to fulfill their current sales commitments, the Midstream Entities must continually contract for new product supplies. The Midstream Entities may not be able to obtain additional contracts for crude oil, condensate, natural gas and NGL supplies. The primary factors affecting the Midstream Entities ability to connect new wells to their gathering facilities include the Midstream Entities success in contracting for existing supplies that are not committed to other systems and the level of drilling activity near their gathering systems. If the Midstream Entities are unable to maintain or increase the volumes on their systems by accessing new supplies to offset the natural decline in reserves, the Midstream Entities business and financial results could be materially, adversely affected. In addition, the Midstream Entities future growth will depend in part upon whether they can contract for additional supplies at a greater rate than the rate of natural decline in their current supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil, condensate and natural gas reserves. Prolonged periods of low commodity prices may put downward pressure on future drilling activity which may result in lower volumes. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of product available to the Midstream Entities systems and assets. Additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current and future volumes from offshore pipelines supplying the Midstream Entities processing plants. The Midstream Entities have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in production or in the level of drilling activity in the Midstream Entities principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on the Midstream Entities results of operations and financial position.

Any decrease in the volumes that the Midstream Entities gather, process, fractionate or transport would adversely affect their financial condition, results of operations and cash flows.

The Midstream Entities financial performance depends to a large extent on the volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on their assets. Decreases in the volumes of natural gas, crude oil, condensate and NGLs we gather, process, fractionate or transport would directly and adversely affect the Midstream Entities revenues and results of operations. These volumes can be influenced by factors beyond the Midstream Entities control, including:

- environmental or other governmental regulations;
- weather conditions;

- increases in storage levels of natural gas and NGLs;
- increased use of alternative energy sources;
- decreased demand for natural gas and NGLs;
- fluctuations in commodity prices, including the prices of natural gas and NGLs;
- economic conditions;
- supply disruptions;
- availability of supply connected to the Midstream Entities systems; and
- availability and adequacy of infrastructure to gather and process supply into and out of the Midstream Entities systems.

The volumes of natural gas, crude oil, condensate and NGLs gathered, processed, fractionated and transported on the Midstream Entities assets also depend on the production from the regions that supply its systems. Supply of natural gas, crude oil, condensate and NGLs can be affected by many of the factors listed above, including commodity prices and weather. In order to maintain or increase throughput levels on the Midstream Entities systems, the Midstream Entities must obtain new sources of natural gas, crude oil, condensate and NGLs. The primary factors affecting the Midstream Entities ability to obtain non-dedicated sources of natural gas, crude oil, condensate and NGLs include (i) the level of successful leasing, permitting and drilling activity in the Midstream Entities areas of operation, (ii) the Midstream Entities ability to compete for volumes from new wells and (iii) the Midstream Entities ability to compete successfully for volumes from sources connected to other pipelines. The Midstream Entities have no control over the level of drilling activity in their areas of operation, the amount of reserves associated with wells connected to their systems or the rate at which production from a well declines. In addition, the Midstream Entities have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment.

Table of Contents

The Midstream Entities construction of new assets may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect the Midstream Entities cash flows, results of operations and financial condition.

The construction of additions or modifications to the Midstream Entities existing systems and the construction of new midstream assets involves numerous regulatory, environmental, political and legal uncertainties beyond their control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If the Midstream Entities undertake these projects, they may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, the Midstream Entities revenues may not increase due to the successful construction of a particular project. For instance, if the Midstream Entities expand a pipeline or construct a new pipeline, the construction may occur over an extended period of time, and they may not receive any material increases in revenues promptly following completion of a project or at all. Moreover, the Midstream Entities may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve their expected investment return, which could adversely affect the Midstream Entities results of operations and financial condition. In addition, the construction of additions to the Midstream Entities existing gathering and processing assets will generally require them to obtain new rights-of-way and permits prior to constructing new pipelines or facilities. The Midstream Entities may be unable to timely obtain such rights-of-way or permits to connect new product supplies to their existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for the Midstream Entities to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, the Midstream Entities cash flows could be adversely affected.

Construction of the Midstream Entities major development projects subjects them to risks of construction delays, cost over-runs, limitations on their growth and negative effects on their operating results, liquidity and financial position.

The Midstream Entities are engaged in the planning and construction of several major development projects, some of which will take a number of months before commercial operation, such as the Partnership s Cajun-Sibon pipeline expansion project and the Bearkat processing facility project. These projects are complex and subject to a number of factors beyond the Midstream Entities control, including delays from third-party landowners, the permitting process, complying with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on the Midstream Entities business, financial condition, results of operations and liquidity. The construction of pipelines and gathering and processing and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed the Midstream Entities estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed the Midstream Entities estimates, their liquidity and capital position could be adversely affected. This level of development activity requires significant effort from the Midstream Entities management and technical personnel and places additional requirements on their financial resources and internal financial controls. The Midstream Entities may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

The Midstream Entities typically do not obtain independent evaluations of hydrocarbon reserves; therefore, volumes the Midstream Entities service in the future could be less than anticipated.

The Midstream Entities typically do not obtain independent evaluations of hydrocarbon reserves connected to their gathering systems or that they otherwise service due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, the Midstream Entities do not have independent estimates of total reserves serviced by their assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves is less than the Midstream Entities anticipate and they are unable to secure additional sources, then the volumes transported on the Midstream Entities gathering systems or that they otherwise service in the future could be less than anticipated. A decline in the volumes could have a material adverse effect on the Midstream Entities results of operations and financial condition.

The Midstream Entities may not be successful in balancing their purchases and sales.

The Midstream Entities are a party to certain long-term gas sales commitments that they satisfy through supplies purchased under long-term gas purchase agreements. When the Midstream Entities enter into those arrangements, their sales obligations generally match their purchase obligations. However, over time the supplies that the Midstream Entities have under contract may decline due to reduced drilling or other causes and the Midstream Entities may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause the Midstream Entities purchases and sales not to be balanced. If the Midstream Entities purchases and sales are not balanced, they will face increased exposure to commodity price risks and could have increased volatility in their operating income.

The Midstream Entities have made commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect the Midstream Entities margins or even result in losses. For

Table of Contents

example, the Partnership is a party to one contract with a term to 2019 to supply approximately 150,000 MMBtu/d of gas. The Partnership buys gas for this contract on several different production-area indices on its North Texas Pipeline and sell the gas into a different market area index. The Partnership realizes a loss on the delivery of gas under this contract each month based on current prices. The pro forma balance sheet as of December 31, 2013 reflects a liability of $100.9 million related to this onerous performance obligation based on forecasted discounted cash obligations in excess of market under this gas delivery contract. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

The Midstream Entities profitability is dependent upon prices and market demand for oil, condensate, natural gas and NGLs, which are beyond their control and have been volatile.

The Midstream Entities are subject to significant risks due to fluctuations in commodity prices. The Midstream Entities are directly exposed to these risks primarily in the gas processing component of their business. For the year ended December 31, 2013, approximately 3.5% of our total gross operating margin, on a pro forma basis giving effect to the business combination, was generated under percent of liquids contracts. Under these contracts the Partnership receives a fee in the form of a percentage of the liquids recovered and the producer bears all the cost of the natural gas shrink. Accordingly, the Partnership s revenues under these contracts is directly impacted by the market price of NGLs.

The Partnership also realizes processing gross operating margins under processing margin (margin) contracts. For the year ended December 31, 2013 approximately 2.2% of our total gross operating margin, on a pro forma basis giving effect to the business combination, was generated under processing margin contracts. The Partnership has a number of processing margin contracts for activities at its Plaquemine, Gibson and Pelican processing plants. Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and it makes a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost (shrink) and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction, or PTR. The Partnership s margins from these contracts can be greatly reduced or eliminated during periods of high natural gas prices relative to liquids prices. Although the Partnership does not currently have any processing margin contracts for its Blue Water and Eunice plants, it does have the opportunity to process liquids from wet gas flowing on the pipelines connected to these plants, as well as its other processing plants, when market pricing is favorable. The Partnership s Eunice and Blue Water plants are not profitable to operate unless market pricing is very favorable.

The Midstream Entities are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of oil, condensate, natural gas and NGLs connected to or near their assets and on their margins for transportation between certain market centers. Low prices for these products will reduce the demand for the Midstream Entities services and volumes on their systems.

In the past, the prices of oil, condensate, natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, crude oil prices (based on the NYMEX futures daily close prices for the prompt month) in 2013 ranged from a high of $110.53 per Bbl in September 2013 to a low of $86.68 per Bbl in April 2013. Weighted average NGL prices in 2013 (based on the Oil Price Information Service (OPIS) Napoleonville daily average spot liquids prices) ranged from a high of $1.09 per gallon in September 2013 to a low of $0.84 per gallon in June 2013. Natural gas prices (based on Gas Daily Henry Hub closing prices) during 2013 ranged from a high of $4.52 per MMBtu in December 2013 to a low of $3.08 per MMBtu in January 2013.

The markets and prices for oil, condensate, natural gas and NGLs depend upon factors beyond the Midstream Entities control. These factors include the supply and demand for oil, condensate, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil, condensate and natural gas production;
- technology, including improved production techniques (particularly with respect to shale development);
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil, natural gas and NGLs;
- international demand for oil and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation, including the regulation of greenhouse gases.

Table of Contents

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas, crude oil and condensate we gather and process. The volatility in commodity prices may cause the Midstream Entities gross operating margin and cash flows to vary widely from period to period. The Partnership s hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the Midstream Entities throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in Item 7A. Quantitative and Qualitative Disclosure about Market Risk. The Partnership s use of derivative financial instruments does not eliminate the Midstream Entities exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce the Partnership s income.

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

The Midstream Entities gathering, processing and transportation assets connect to other pipelines or facilities owned and operated by unaffiliated third parties, including Atmos Energy, Enable Midstream Partners, ONEOK Partners and others. The continuing operation of, and the Midstream Entities continuing access to, such third-party pipelines, processing facilities and other midstream facilities is not within the Midstream Entities control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if the Midstream Entities costs to access and transport on these third-party pipelines significantly increase, the Midstream Entities profitability could be reduced. If any such increase in costs occurs, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes the Midstream Entities gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, the Midstream Entities operating margin and cash flow could be adversely affected.

The Partnership s debt levels could limit our flexibility and adversely affect its financial health or limit its flexibility to obtain financing and to pursue other business opportunities.

The Partnership continues to have the ability to incur debt, subject to limitations in its credit facility. The Partnership s level of indebtedness could have important consequences to it, including the following:

- the Partnership s ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- the Partnership s funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of the Partnership s cash flows required to make interest payments on its debt;

- the Partnership s debt level will make it more vulnerable to general adverse economic and industry conditions; and

- limit the Partnership s flexibility in planning for, or reacting to, changes in its business and the industry in which it operates.

In addition, the Partnership s ability to make scheduled payments or to refinance our obligations depends on its successful financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, many of which are beyond the Partnership s control. If the Partnership s cash flow and capital resources are insufficient to fund its debt service obligations, the Partnership may be forced to take actions such as reducing distributions, reducing or delaying its business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing its debt or seeking additional equity capital. The Partnership may not be able to effect any of these actions on satisfactory terms or at all.

The Midstream Entities are vulnerable to operational, regulatory and other risks due to their concentration of assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

The Partnership s operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because the Partnership has a significant portion of its assets located in these two areas. The Partnership s concentration of activity in Louisiana and the Gulf of Mexico makes the Partnership more vulnerable than many of its competitors to the risks associated with these areas, including:

- adverse weather conditions, including hurricanes and tropical storms;

- delays or decreases in production, the availability of equipment, facilities or services; and

- changes in the regulatory environment.

Table of Contents

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on the Partnership s results of operations than they might have on other midstream companies that have operations in more diversified geographic areas.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect the Midstream Entities results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons could result in a decline in the volume of NGL products the Midstream Entities handle or reduce the fees the Midstream Entities charge for their services. The Midstream Entities NGL products and the demand for these products are affected as follows:

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

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

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

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

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

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

The Midstream Entities expect to encounter significant competition in any new geographic areas into which they seek to expand, and the Midstream Entities ability to enter such markets may be limited.

If the Midstream Entities expand their operations into new geographic areas, the Midstream Entities expect to encounter significant competition for natural gas, condensate, NGLs and crude oil supplies and markets. Competitors in these new markets will include companies larger than the Midstream Entities, which have both lower cost of capital and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, the Midstream Entities may not be able to successfully develop acquired assets and markets located in new geographic areas and their results of operations could be adversely affected.

With completion of the business combination, the size of the combined business of the Midstream Entities was significantly increased and expanded into geographic regions in which the former Crosstex Energy, L.P. did not previously operate, including the Cana and Arkoma Woodford Shales in Oklahoma. In order to operate effectively in these new regions, the Midstream Entities need to understand the local market and regulatory environment and identify and retain certain employees from Devon who are familiar with these markets. If the Midstream Entities are not successful in retaining these employees or operating in these new geographic areas, they may not be able to compete effectively in the new markets or fully realize the expected benefits of the business combination.

Table of Contents

The terms of the Partnership s credit facility and indentures may restrict its current and future operations, particularly its ability to respond to changes in business or to take certain actions.

The Partnership s credit agreement and the indentures governing its senior notes contain, and any future indebtedness the Partnership incurs will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on the Partnership s ability to engage in acts that may be in its best long-term interest. In addition, the Partnership s credit facility requires it to satisfy and maintain a specified financial ratio. The Partnership s ability to meet that financial ratio can be affected by events beyond its control, and we cannot assure you that the Partnership will continue to meet that ratio.

A breach of any of these covenants could result in an event of default under the Partnership s credit facility and indentures. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If indebtedness under the Partnership s credit facility or indentures is accelerated, there can be no assurance that it will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

The Midstream Entities do not own most of the land on which their pipelines and compression facilities are located, which could disrupt their operations.

The Midstream Entities do not own most of the land on which their pipelines and compression facilities are located, and they are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if they do not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. The Midstream Entities sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. The Midstream Entities loss of these rights, through their inability to renew right-of-way contracts, leases or otherwise, could cause them to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce their revenue.

The Midstream Entities offer pipeline, truck, rail and barge services. Significant delays, inclement weather or increased costs affecting these transportation methods could materially affect the Midstream Entities operations and earnings.

The Midstream Entities offer pipeline, truck, rail and barge services. The costs of conducting these services could be negatively affected by factors outside of the Midstream Entities control, including rail service interruptions, new laws and regulations, rate increases, tariffs, rising fuel costs or capacity constraints. Inclement weather, including hurricanes, tornadoes, snow, ice and other weather events, can negatively impact the Midstream Entities distribution network. In addition, rail, truck or barge accidents involving the transportation of hazardous materials could result in significant claims arising from personal injury, property damage and environmental penalties and remediation.

The Midstream Entities could experience increased severity or frequency of trucking accidents and other claims.

Potential liability associated with accidents in the trucking industry is severe and occurrences are unpredictable. A material increase in the frequency or severity of accidents or workers compensation claims or the unfavorable development of existing claims could be expected to materially adversely affect the Midstream Entities results of operations. In the event that accidents occur, the Midstream Entities may be unable to obtain desired contractual indemnities, and their insurance may be inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses.

Changes in trucking regulations may increase the Midstream Entities costs and negatively impact their results of operations.

The Midstream Entities trucking services are subject to regulation as a motor carrier by the United States Department of Transportation (DOT) and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over the Midstream Entities trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact the Midstream Entities operations and affect the economics of the industry by requiring changes in operating practices or by changing the demand for or the cost of providing trucking services. Some of these possible changes include increasingly stringent fuel emission limits, changes in the regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements.

If the Midstream Entities do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with their asset base, their future growth will be limited.

The Midstream Entities ability to grow depends, in part, on their ability to make acquisitions that result in an increase in cash generated from operations on a per unit basis. If the Midstream Entities are unable to make accretive acquisitions either because they are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or at all or (3) outbid by competitors, then their future growth and ability to increase distributions will be limited.

Table of Contents

From time to time, the Midstream Entities may evaluate and seek to acquire assets or businesses that they believe complement their existing business and related assets. The Midstream Entities may acquire assets or businesses that they plan to use in a manner materially different from their prior owner s use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management s attention from other business concerns;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- the coordination of geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in the Midstream Entities indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management s assessment of these risks is inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect the Midstream Entities operations and cash flows. If the Midstream Entities consummate any future acquisition, their capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that the Midstream Entities will consider in determining the application of these funds and other resources.

The Midstream Entities may not be able to retain existing customers or acquire new customers, which would reduce their revenues and limit their future profitability.

The renewal or replacement of existing contracts with the Midstream Entities customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond the Midstream Entities control, including competition from other midstream service providers, and the price of, and demand for, crude oil, condensate, NGLs and natural gas in the markets they serve. The inability of the Midstream Entities management to renew or replace their current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on the Midstream Entities profitability.

In particular, the Midstream Entities ability to renew or replace their existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2013, approximately 51.0% of the Midstream Entities sales of gas that was transported using the Midstream Entities physical facilities were to industrial end-users and utilities, on a pro forma basis giving effect to the business combination. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities may be reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with the Midstream Entities in the marketing of natural gas, the Midstream Entities often compete in the end-user and utilities markets primarily on the basis of price.

The Midstream Entities are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by their customers could have an adverse effect on their financial condition and results of operations.

Risks of nonpayment and nonperformance by the Midstream Entities customers are a major concern in their business. The Midstream Entities are subject to risks of loss resulting from nonpayment or nonperformance by their customers and other counterparties, such as their lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by the Midstream Entities customers could adversely affect their results of operations and reduce their ability to make distributions to us.

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

A portion of the Midstream Entities suppliers and customers natural gas production is developed from unconventional sources, such as deep gas shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Hydraulic fracturing activities are generally regulated by state oil and gas commissions; however, the Environmental Protection Agency (the EPA) has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has released draft permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where the EPA is the permitting authority. In addition, legislation has been proposed, but not passed that would provide for federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic-fracturing process. State legislatures and agencies are also enacting legislation and promulgating rules to regulate hydraulic fracturing and require disclosure of hydraulic fracturing chemicals.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. In addition, the EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and has initiated plans to promulgate regulations controlling wastewater disposal associated with hydraulic fracturing and shale gas development. In addition to the EPA, other federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms. 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.

We cannot predict whether any additional legislation or regulations will be enacted and, if so, what the provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions for the Midstream Entities suppliers and customers that could reduce the volumes of natural gas that move through the Midstream Entities gathering systems which could materially adversely affect their revenue and results of operations.

Transportation on certain of the Midstream Entities natural gas pipelines is subject to federal and state rate and service regulation, which could limit the revenues the Midstream Entities collect from their customers and adversely affect the cash available for distribution to us. The imposition of regulation on the Midstream Entities currently unregulated natural gas pipelines also could increase their operating costs and adversely affect the cash available for distribution to us.

The rates, terms and conditions of service under which the Midstream Entities transport natural gas in their pipeline systems in interstate commerce are subject to regulation of the Federal Energy Regulatory Commission (FERC) under Section 311 of the Natural Gas Policy Act and the rules and regulations promulgated under that statute. Under these regulations, the Midstream Entities are required to justify our rates for interstate transportation service on a cost-of-service basis every five years. The Midstream Entities intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that the Midstream Entities rates for Section 311 transportation service or intrastate transportation service should be lowered, the Midstream Entities business could be adversely affected.

The Midstream Entities natural gas gathering and processing activities generally are exempt from FERC regulation under the Natural Gas Act. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of the Midstream Entities gathering facilities are subject to change based on future determinations by FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. The Midstream Entities gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on the Midstream Entities operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Other state and local regulations also affect the Midstream Entities business. The Midstream Entities are subject to some ratable take and common purchaser statutes in the states where they operate. 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 have the effect of restricting the Midstream Entities right as an owner of gathering facilities to decide with whom the Midstream Entities contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which the Midstream Entities operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

Transportation on the Partnership s liquids pipelines is subject to federal rate and service regulation, which could limit the revenues the Partnership collects from its customers and adversely affect the cash available for distribution to us.

The Partnership s liquids transportation pipelines in the Ohio River Valley and the Cajun-Sibon NGL pipeline, which went into service in November 2013, are subject to regulation by FERC under the ICA, the Energy Policy Act of 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates and terms and conditions of service for interstate service on liquids pipelines be just, reasonable and not unduly discriminatory or preferential. The ICA also requires that such rates and terms and conditions be set forth in tariffs filed with FERC. The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new

Table of Contents

or changed rates are unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rates during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit the Partnership s ability to set rates based on its costs or could order the Partnership to reduce its rates and could require the payment of reparations to complaining shippers for up to two years prior to the date of the complaint. FERC also has the authority to change the Partnership s terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential.

As the Midstream Entities acquire, construct and operate new liquids assets and expand our liquids transportation business, the classification and regulation of their liquids transportation services are subject to ongoing assessment and change based on the services they provide and determinations by FERC and the courts. Such changes may subject additional services we provide to regulation by FERC, which could increase the Midstream Entities operating costs, decrease their rates and adversely affect their business.

The Midstream Entities may incur significant costs and liabilities resulting from compliance with pipeline safety regulations.

The states in which the Midstream Entities conduct operations administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968. These standards only apply to certain natural gas gathering lines based on the gathering line s operating pressure and proximity to people. Because of their pressure and location, substantial portions of the Midstream Entities gathering facilities are not regulated under that statute. The gathering line exemptions, however, may be revised in the future and place more of the Midstream Entities gathering facilities under jurisdiction of the DOT. Nonetheless, the Midstream Entities natural gas transmission pipelines are subject to regulation by the DOT. In response to pipeline accidents in other parts of the country, Congress and the DOT, through PHMSA, have passed or are considering heightened pipeline safety requirements that may be applicable to gathering lines. As a result, the Midstream Entities pipeline facilities are subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which reauthorized funding for federal safety programs through 2015, increased penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

At the state level, several states have passed legislation or promulgated rulemaking addressing pipeline safety. Compliance with pipeline integrity and other pipeline safety regulations issued by DOT or those issued by the Texas Railroad Commission, or TRRC, could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. The Midstream Entities costs relating to compliance with the required testing under the TRRC regulations were approximately at $7.0 million, $8.6 million, and $7.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $5.0 million during 2014. If the Midstream Entities pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then they may be required to repair or replace sections of such pipelines or operate the pipelines at a reduced maximum allowable operating pressure, the cost of which cannot be estimated at this time.

In addition, the Midstream Entities liquids transportation pipelines are subject to regulation by the DOT, through the Pipeline and Hazardous Materials Safety Administration, or PHMSA, pursuant to the Hazardous Liquids Pipeline Safety Act of 1979, as amended by the Pipeline Safety Improvement Act of 2002, and reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. PHMSA has adopted regulations requiring hazardous liquid pipeline operators to develop and implement integrity management programs for pipeline segments that, in the event of a leak or rupture, could affect high consequence areas, such as high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area.

Due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the PHMSA or state requirements will not have a material adverse effect on our results of operations or financial positions. As the Midstream Entities operations continue to expand into and around urban or more populated areas, such as the Barnett Shale, the Midstream Entities may incur additional expenses to mitigate noise, odor and light that may be emitted in their operations and expenses related to the appearance of their facilities. Municipal and other local or state regulations are imposing various obligations including, among other things, regulating the location of Midstream Entities facilities, imposing limitations on the noise levels of their facilities and requiring certain other improvements that increase the cost of our facilities. The Midstream Entities are also subject to claims by neighboring landowners for nuisance related to the construction and operation of Midstream Entities facilities, which could subject them to damages for declines in neighboring property values due to their construction and operation of facilities.

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause the Midstream Entities to incur significant costs and liabilities.

Many of the operations and activities of our gathering systems, processing plants, fractionators, brine disposal operations and other facilities are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from the Midstream Entities facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by the Midstream Entities or locations to which they have sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Strict, joint and several liability may be incurred under these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties near the Midstream Entities facilities or upon or through which their gathering systems traverse, 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 for releases of contaminants or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in the Midstream Entities business due to their handling of natural gas, crude oil and other petroleum substances, the Partnership s brine disposal operations, air emissions related to the Midstream Entities operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. For example, the Partnership operates brine disposal wells in Ohio and West Virginia and may gather brine from surrounding states. These wells are regulated under the federal Safe Drinking Water Act (SDWA) as Class II wells and under state laws. State laws and regulations that govern these operations can be more stringent than the federal SDWA, such as the Ohio Department of Natural Resources rules which took effect October 1, 2012. These rules imposed new, more stringent environmentally responsible standards for the permitting and operating of brine disposal wells, including extensive review of geologic data and use of state of the art technology. They apply to new disposal wells and, as applicable, to existing wells. The Ohio Department of Natural Resources also imposes requirements on the transportation and disposal of brine. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. The Midstream Entities may incur material environmental costs and liabilities. Furthermore, the Midstream Entities insurance may not provide sufficient coverage in the event an environmental claim is made against them.

In addition, state and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity. To the extent these studies result in additional regulation of injection wells, such regulations could impose additional regulations, costs and restrictions on the Partnership s brine disposal operations.

The Midstream Entities business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation relating to the control of greenhouse gas emissions, or changes in existing environmental laws or regulations might adversely affect the Midstream Entities products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect the Midstream Entities profitability. Changes in laws or regulations could also limit the Midstream Entities production or the operation of their assets or adversely affect the Midstream Entities ability to comply with applicable legal requirements or the demand for crude oil, brine disposal services or natural gas, which could adversely affect the Midstream Entities business and profitability.

Recently finalized rules under the Clean Air Act imposing more stringent requirements on the oil and gas industry could cause the Midstream Entities and their customers to incur increased capital expenditures and operating costs as well as reduce the demand for the Midstream Entities services.

On April 17, 2012, the EPA issued final rules under the Clean Air Act that became effective on October 15, 2012. Among other things, these rules require additional emissions controls for natural gas and NGLs production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or green completions on all hydraulically fractured wells constructed or refractured after January 1, 2015. Moreover, these rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. The rules also establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. These regulations could require a number of modifications to our operations and our natural gas exploration and production suppliers and customers operations, including the installation of new equipment, which could result in significant costs, including increased capital expenditures and operating costs. The incurrence of such expenditures and costs by the Midstream Entities suppliers and customers could result in reduced production by those suppliers and customers and thus translate into reduced demand for the Midstream Entities services. The rules are subject to an ongoing legal challenge brought by various parties, including environmental groups and industry, and the EPA has indicated that it may revise the rules. Any such revisions could affect the Midstream Entities operations, as well as the operations of their suppliers and customers.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services the Midstream entities provide.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. These findings allowed the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. Since 2011, the EPA has required stationary sources that emit GHGs above regulatory and statutory thresholds to obtain a Prevention of Significant Deterioration permit. Moreover, on October 30, 2009, the EPA published a Mandatory Reporting of Greenhouse Gases final rule that established a comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of GHGs to inventory and report their GHG emissions

Table of Contents

annually on a facility-by-facility basis. The Mandatory Reporting Rule was expanded by a rule promulgated on November 30, 2010 to include owners and operators of onshore oil and natural gas production, processing, transmission, storage and distribution facilities. Reporting emissions from such onshore activities is required on an annual basis. The first reports were due in 2012 for emissions occurring in 2011. Additionally, the EPA has proposed to regulate greenhouse gas emissions from certain electric generating units under the Clean Air Act s New Source Performance Standards (NSPS) program. The EPA may propose to regulate additional source categories under the NSPS program in the future.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, the Midstream Entities equipment and operations could require the Midstream Entities to incur additional costs to reduce emissions of GHGs associated with their operations, could adversely affect their performance of operations in the absence of any permits that may be required to regulate emission of GHGs or could adversely affect demand for the natural gas the Midstream Entities gather, process or otherwise handle in connection with their services.

The Midstream Entities business involves many hazards and operational risks, some of which may not be fully covered by insurance.

The Midstream Entities operations are subject to the many hazards inherent in the gathering, compressing, processing, transporting, fractionating, disposing and storage of natural gas, NGLs, condensate, crude oil and brine, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons;
- induced seismicity;
- rail accidents, barge accidents and truck accidents; and

- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of the Midstream Entities related operations. The Midstream Entities are not fully insured against all risks incident to their business. In accordance with typical industry practice, the Midstream Entities do not have business interruption insurance or any property insurance on any of their underground pipeline systems that would cover damage to the pipelines. The Midstream Entities are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect the Midstream Entities operations and financial condition.

The adoption of derivatives legislation by the United States Congress and promulgation of related regulations could have an adverse effect on our ability to hedge risks associated with the Midstream Entities business.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission (CFTC) to regulate certain markets for derivative products, including over-the-counter (OTC) derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Midstream Entities encounter, reduce the Partnership s ability to monetize or restructure the Partnership s existing derivative contracts, and increase the Midstream Entities exposure to less creditworthy counterparties. If the Partnership reduces its use of derivatives as a result of the legislation and regulations, the Partnership s results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect the Partnership s ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. The Partnership s revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on the Midstream Entities, their financial condition and their results of operations.

Table of Contents

The Partnership s use of derivative financial instruments does not eliminate its exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce its income.

The Partnership s operations expose us to fluctuations in commodity prices, and the Partnership s credit facility exposes it to fluctuations in interest rates. The Partnership uses over-the-counter price and basis swaps with other natural gas merchants and financial institutions. Use of these instruments is intended to reduce the Partnership s exposure to short-term volatility in commodity prices. As of December 31, 2013, the Partnership had hedged only portions of its expected exposures to commodity price risk. In addition, to the extent the Partnership hedges it commodity price risk using swap instruments, the Partnership will forego the benefits of favorable changes in commodity prices. Although the Partnership does not currently have any financial instruments to eliminate its exposure to interest rate fluctuations, we may use financial instruments in the future to offset its exposure to interest rate fluctuations.

Even though monitored by management, the Partnership s hedging activities may fail to protect it and could reduce its earnings and cash flow. The Partnership s hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;

- the Partnership s counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and

- available hedges may not correspond directly with the risks against which the Partnership seeks protection. For example:

- the duration of a hedge may not match the duration of the risk against which the Partnership seeks protection;

- variations in the index the Partnership uses to price a commodity hedge may not adequately correlate with variations in the index the Partnership uses to sell the physical commodity (known as basis risk); and

- the Partnership may not produce or process sufficient volumes to cover swap arrangements the Partnership enters into for a given period. If the Partnership s actual volumes are lower than the volumes the Partnership estimated when entering into a swap for the period, it might be forced to satisfy all or a portion of its derivative obligation without the benefit of cash flow from the sale or purchase of the underlying physical commodity, which could adversely affect the Partnership s liquidity.

The Partnership s financial statements may reflect gains or losses arising from exposure to commodity prices for which it is unable to enter into fully effective hedges. In addition, the standards for cash flow hedge accounting are rigorous. Even when the Partnership engages in hedging transactions that are effective economically, these transactions may not be considered effective cash flow hedges for accounting purposes. The

Partnership s earnings could be subject to increased volatility to the extent its derivatives do not continue to qualify as cash flow hedges and, if it assumes derivatives as part of an acquisition, to the extent it cannot obtain or chooses not to seek cash flow hedge accounting for the derivatives it assumes.

The Midstream Entities success depends on key members of their management, the loss or replacement of whom could disrupt their business operations.

The Midstream Entities depend on the continued employment and performance of the officers of the General Partner and key operational personnel. The Partnership s General Partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, the Midstream Entities business operations could be materially adversely affected. The Midstream Entities do not maintain any key man life insurance for any officers.

Item 1B. ***Unresolved Staff Comments***

We do not have any unresolved staff comments.

Item 2. ***Properties***

A description of our properties is contained in Item 1. Business.

Title to Properties

Substantially all of the Midstream Entities pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. The Midstream Entities have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which the Midstream Entities pipelines were built was purchased in fee. The Midstream Entities processing plants are located on land that the Midstream Entities lease or own in fee.

Table of Contents

We believe that the Midstream Entities have satisfactory title to all of their rights-of-way and land assets. Title to these assets may be subject to encumbrances or defects. The Midstream Entities believe that none of such encumbrances or defects should materially detract from the value of their assets or from their interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. ***Legal Proceedings***

Our operations and those of the Midstream Entities are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we or the Midstream Entities may be a defendant in various legal proceedings and litigation arising in the ordinary course of business, including litigation on disputes related to contracts, property use or damage and personal injury. Additionally, as the Midstream Entities continue to expand operations into more urban, populated areas, such as the Barnett Shale, they may see an increase in claims brought by area landowners, such as nuisance claims and other claims based on property rights. Except as otherwise set forth herein, we do not believe that any pending or threatened claim or dispute is material to our financial results on our operations. We maintain insurance policies with insurers in amounts and with coverage and deductibles as our general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

At times, the Partnership s gas-utility and common carrier subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain. As a result, the Partnership (or its subsidiaries) are party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership s gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value, if any, of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on the Partnership s consolidated results of operations or financial condition.

From time to time, owners of property located near the Midstream Entities processing facilities or compression facilities file lawsuits against them. These suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. The Partnership has appealed the matter and have posted a bond to secure the judgment pending its resolution. The Partnership has accrued a $2.0 million liability related to this matter. Although it is not possible to predict the ultimate outcomes of these matters, we do not expect that awards in these matters will have a material adverse impact on the Partnership s consolidated results of operations or financial condition.

Item 4. ***Mine Safety Disclosures***

Not applicable.

Table of Contents

PART II

Item 5. *Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our common units are listed on The New York Stock Exchange under the symbol ENLC. Our common units began trading on March 10, 2014. There was no established public market for our common units prior to March 10, 2014. On March 26, 2014, the closing market price for our common units was $33.97 per common unit and there were approximately 13,788 record holders and beneficial owners (held in street name) of our common units. For equity compensation plan information, see discussion under Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters Equity Compensation Plan Information.

We have not yet declared any distributions to our unitholders. We intend to pay distributions to our unitholders on a quarterly basis equal to the cash we receive, if any, from distributions from the Partnership and Midstream Holdings and, if applicable, E2, less reserves for expenses, future distributions and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;

- the expenses of being a public company;

- other general and administrative expenses;

- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner s then-current general partner interest, to the extent the board of directors of the general partner exercises its option to do so; and

- cash reserves our board of directors believes are prudent to maintain.

Our ability to pay distributions is limited by the Delaware Limited Liability Company Act, which provides that a limited liability company may not pay distributions if, after giving effect to the distribution, the company s liabilities would exceed the fair value of its assets. While our ownership of equity interests in the general partner, the Partnership, Midstream Holdings and E2 are included in our calculation of net assets, the value of these assets may decline to a level where our liabilities would exceed the fair value of our assets if we were to pay distributions, thus prohibiting us from paying distributions under Delaware law.

Item 6. ***Selected Financial Data***

The following table presents the selected historical financial and operating data of EnLink Midstream Holdings, LP Predecessor (the Predecessor) for the periods indicated. The Predecessor is comprised of all of the U.S. midstream assets and operations of Devon prior to the business combination, including its 38.75% economic interest in Gulf Coast Fractionators. The selected combined historical financial data of the Predecessor are derived from the historical combined financial statements of the Predecessor and should be read together with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations below and its audited combined financial statements for the year ended December 31, 2013. The following information is only a summary and is not necessarily indicative of the results or future operations of the Predecessor.

	Year Ended December 31,				
	2013	2012	2011	2010	2009 (unaudited)
	(in millions, except per unit and operating data)				
Key Performance Measure					
Operating Margin (1)	$ 446.3	$ 365.3	$ 453.8	$ 427.6	$ 366.8
Operating Data					
Throughput (thousands of MMBtu/d)	2,708.4	2,720.6	2,637.4	2,470.0	2,294.2
NGL production (MBbls/d)	88.6	71.0	69.7	62.1	59.3
Statement of Income Data					
Operating revenues	$ 2,390.7	$ 2,000.8	$ 2,623.4	$ 2,016.0	$ 1,609.1
Operating expenses	(2,227.1)	(1,899.2)	(2,311.8)	(1,766.9)	(1,436.7)
Operating income	163.6	101.6	311.6	249.1	172.4
Income from equity investment	14.8	2.0	9.3	5.1	5.0
Income tax expense	(64.2)	(37.3)	(115.5)	(91.5)	(63.8)
Net income from continuing operations	114.2	66.3	205.4	162.7	113.6
Net income from discontinued operations	1.3	9.5	10.7	16.0	11.6
Net income	$ 115.5	$ 75.8	$ 216.1	$ 178.7	$ 125.2
Balance Sheet Data					
Net property, plant and equipment	$ 1,840.4	$ 1,843.2	$ 1,687.0	$ 1,574.6	$ 1,499.2
Total assets	$ 2,309.8	$ 2,535.2	$ 2,446.3	$ 2,336.0	$ 2,276.6
Total long-term liabilities	$ 481.4	$ 449.8	$ 461.0	$ 418.0	$ 318.1
Total equity	$ 1,783.7	$ 2,002.0	$ 1,901.3	$ 1,849.0	$ 1,869.7
Cash Flow Data					
Net cash flows provided by (used in):					
Operating activities	$ 360.5	$ 254.4	$ 401.2	$ 391.5	$
Investing activities	$ (242.9)	$ (368.5)	$ (268.6)	$ (220.4)	$
Financing activities	$ (117.6)	$ 114.1	$ (132.6)	$ (171.1)	$

(1) Operating margin is a non-GAAP financial measure. See below for additional information and a reconciliation of operating margin to operating income, which is its most directly comparable GAAP financial measure.

Table of Contents

Predecessor Non-GAAP Financial Measure

The selected combined historical financial data of the Predecessor includes operating margin, a non-GAAP financial measure.

The Predecessor s operating margin is defined as operating revenues less product purchases and operations and maintenance expenses. The Predecessor uses operating margin as a performance measure of the core profitability of its operations. As an indicator of the Predecessor s operating performance, operating margin should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP. The Predecessor s operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

The following table provides a reconciliation of the Predecessor s operating margin to operating income, which is the most directly comparable GAAP financial measure:

	Years Ended December 31, (in millions)				
	2013	**2012**	**2011**	**2010**	**2009**
Predecessor s operating margin	$ 446.3	$ 365.3	$ 453.8	$ 427.6	$ 366.8
Add (deduct):					
Depreciation and amortization	(199.0)	(159.8)	(144.8)	(124.9)	(136.6)
General and administrative	(47.0)	(43.6)	(40.1)	(39.4)	(44.8)
Non-income taxes	(18.0)	(13.2)	(15.3)	(13.8)	(12.5)
Asset impairments	(18.2)	(50.1)			
Other, net	(0.5)	3.0	58.0	(0.4)	(0.5)
Operating income	$ 163.6	$ 101.6	$ 311.6	$ 249.1	$ 172.4

Table of Contents

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

The historical financial statements included in this report reflect the assets, liabilities and operations of EnLink Midstream Holdings, LP Predecessor (the Predecessor), the predecessor to Midstream Holdings, which is the historical predecessor of EnLink Midstream, LLC. The Predecessor is comprised of all of the U.S. midstream assets and operations of Devon Energy Corporation (Devon) prior to the business combination, including its 38.75% economic interest in Gulf Coast Fractionators. However, in connection with the business combination, only the Predecessor s systems serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales in Texas and Oklahoma, as well as the economic burdens and benefits of the 38.75% economic interest in Gulf Coast Fractionators, were contributed to Midstream Holdings, effective as of December 31, 2013. These contributed assets represent 95.2% of the Predecessor s operating income for the year ended December 31, 2013.

The following discussion analyzes the results of operations and financial condition of the Predecessor, including the less significant assets that were not contributed to Midstream Holdings in connection with the business combination. You should read this discussion in conjunction with the historical financial statements and accompanying notes included in this report. All references in this section to Midstream Holdings, as well as the terms our, we, us and its, refer to the Predecessor when used in historical context. All references in this section to Midstream Holdings when referring to current or future events refer to EnLink Midstream Holdings, LP, together with its consolidated subsidiaries. All references in this section to the Company, as well as the terms our, we, us and its, refer to EnLink Midstream, LLC, together with its consolidated subsidiaries, when referring to current or future events.

Overview

We are a Delaware limited liability company formed in October 2013. Our assets consist of equity interests in EnLink Midstream Partners, LP, EnLink Midstream Holdings, LP, E2 Energy Services, LLC and E2 Appalachian Compression, LLC (collectively, E2). EnLink Midstream Partners, LP is a publicly traded limited partnership engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs, condensate and crude oil, as well as providing crude oil, condensate and brine services to producers. EnLink Midstream Holdings, LP, a partnership owned by the Partnership and us, is engaged in the gathering, transmission and processing of natural gas. E2 is a services company focused on the Utica Shale play in the Ohio River Valley.

Effective as of March 7, 2014, EnLink Midstream, Inc. (formerly known as Crosstex Energy, Inc.) (EMI) merged with and into our wholly-owned subsidiary and Acacia Natural Gas Corp I, Inc. (New Acacia), formerly a wholly-owned subsidiary of Devon, merged with and into a wholly-owned subsidiary of the Company (collectively, the mergers). Pursuant to the mergers, each of EMI and New Acacia became wholly-owned subsidiaries of the Company and the Company became publicly held. EMI owns common units representing an approximate 7% limited partner interest in EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.) (the Partnership) as of March 24, 2014 and also owns EnLink Midstream Partners GP, LLC (formerly known as Crosstex Energy GP, LLC) (the General Partner). New Acacia directly owns a 50% limited partner interest in EnLink Midstream Holdings, LP (Midstream Holdings). Concurrently with the consummation of the mergers, a wholly-owned subsidiary of the Partnership acquired the remaining 50% of the outstanding limited partner interest in Midstream Holdings and all of the outstanding equity interests in EnLink Midstream Holdings GP, LLC, the general partner of Midstream Holdings (together with the mergers, the business combination).

Midstream Holdings owns midstream assets consisting of natural gas gathering and transportation systems, natural gas processing facilities and NGL fractionation facilities located in Texas and Oklahoma. Midstream Holdings primary assets consist of three processing facilities with 1.3 Bcf/d of natural gas processing capacity, approximately 3,685 miles of pipelines with aggregate capacity of 2.9 Bcf/d and fractionation facilities with up to 160 MBbls/d of aggregate NGL fractionation capacity. These assets include the following systems and facilities.

• ***Barnett assets*** Midstream Holdings owns the following midstream assets in the Barnett Shale:

• *Bridgeport processing facility* This natural gas processing facility is one of the largest processing plants in the U.S. with 790 MMcf/d of processing capacity, 63 MBbls/d of NGL production capacity and 15 MBbls/d of NGL fractionation capacity.

• *Bridgeport rich gathering system* This rich natural gas gathering system consists of approximately 2,442 miles of low- and intermediate-pressure pipeline segments with approximately 145,000 horsepower of compression.

Table of Contents

- *Bridgeport lean gathering system* This lean natural gas gathering system consists of approximately 300 miles of low-, intermediate- and high-pressure pipeline segments with approximately 59,000 horsepower of compression.

- *Acacia transmission system* This transmission system consists of approximately 120 miles of pipeline, associated storage and approximately 17,000 horsepower of compression and interconnects the tailgate of the Bridgeport processing facility and the Bridgeport lean gathering system to intrastate pipelines as well as two local power plants.

- *East Johnson County gathering system* This natural gas gathering system consists of approximately 270 miles of low-, intermediate- and high-pressure pipeline segments with approximately 41,000 horsepower of compression.

- ***Cana system*** This natural gas gathering and processing system is located in the Cana-Woodford Shale in West Central Oklahoma and consists of a 350 MMcf/d processing facility, 30 MBbls/d of NGL production capacity and approximately 413 miles of associated low-, intermediate- and high-pressure pipeline segments with approximately 92,500 horsepower of compression.

- ***Northridge system*** This natural gas gathering and processing system is located in the Arkoma-Woodford Shale in Southeastern Oklahoma and consists of a 200 MMcf/d processing facility, 17 MBbls/d of NGL production capacity and approximately 140 miles of associated low-, intermediate- and high-pressure pipeline segments with approximately 18,000 horsepower of compression.

- ***Gulf Coast Fractionators*** Midstream Holdings holds a contractual right to the economic burdens and benefits of a 38.75% interest in Gulf Coast Fractionators held by Devon. Gulf Coast Fractionators owns an NGL fractionator located on the Texas Gulf Coast at the Mont Belvieu hub. This facility has a capacity of approximately 145 MBbls/d.

Midstream Holdings Operations

Midstream Holdings results are driven primarily by the volumes of natural gas it gathers, processes and transports through its systems. This volume throughput is substantially dependent on Devon s success in the regions where Midstream Holdings operates. Devon is a leading independent energy company engaged primarily in the exploration, development and production of oil, natural gas and NGLs. Devon is the largest natural gas producer in the Barnett and Cana-Woodford Shales, the largest NGL producer in the Barnett Shale and one of the largest NGL producers in the Cana-Woodford Shale.

In Midstream Holdings gathering operations, it contracts with producers to gather natural gas from individual wells located near its gathering systems. Midstream Holdings connects wells to gathering lines through which natural gas is compressed and may be delivered to a processing plant or downstream pipeline, and ultimately to end-users.

The Predecessor historically provided services to Devon pursuant to fixed-fee and percent-of-proceeds contracts and historically took title to the natural gas it gathered and processed. The Predecessor s percent-of-proceeds arrangements were based on the sales value of extracted NGLs and residue natural gas that resulted from natural gas processing.

In connection with the consummation of the Merger, Midstream Holdings has entered into new contracts with Devon pursuant to which it provides services under fixed-fee arrangements based on the volume and thermal content of the natural gas gathered, processed and transported and does not take title to the natural gas gathered, processed and transported. Under these arrangements, Midstream Holdings provides gathering and processing services to Devon, and Devon has dedicated to Midstream Holdings natural gas production for 10 years from 795,000 net acres in the Barnett, Cana-Woodford and Arkoma-Woodford Shales. Midstream Holdings expects all of these dedications to result in associated deliveries to its Bridgeport, Cana, East Johnson County and Northridge systems. Devon has provided five-year minimum natural gas volume commitments to Midstream Holdings of 850 MMcf/d to the Bridgeport gathering systems, 650 MMcf/d to the Bridgeport processing facility, 125 MMcf/d to the East Johnson County gathering system, 330 MMcf/d to the Cana system and 40 MMcf/d to the Northridge system.

Midstream Holdings believes these contracts provide it with a relatively steady revenue stream that is not subject to direct commodity price risk during the term of the five-year minimum volume commitments. After the five-year minimum volume commitments, Midstream Holdings will nevertheless continue to have indirect exposure to commodity price risk in that persistently low commodity prices may cause Devon to delay drilling or shut in production, which would reduce the throughput on Midstream Holdings assets.

How Midstream Holdings Evaluates its Operations

Midstream Holdings uses a variety of financial and operational metrics to evaluate its performance. These metrics help Midstream Holdings identify factors and trends that impact Midstream Holdings operating results, profitability and financial condition. The key metrics Midstream Holdings uses to evaluate its business are provided below.

Table of Contents

Operating Margin

Midstream Holdings uses operating margin as a performance measure of the core profitability of its operations. Midstream Holdings defines operating margin as total operating revenues, which consist of revenues generated from the sale of natural gas and NGLs plus service fee revenues, less the cost of product purchases, consisting primarily of producer payments and other natural gas purchases, and operations and maintenance expenses. Midstream Holdings uses operating margin to assess:

- the financial performance of Midstream Holdings assets, without regard to financing methods, capital structure or historical cost basis;
- Midstream Holdings operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects.

Natural Gas Throughput

Midstream Holdings must continually obtain additional supplies of natural gas to maintain or increase throughput on its systems. Midstream Holdings ability to maintain existing supplies of natural gas and obtain additional supplies is primarily impacted by its acreage dedication and the level of successful drilling activity by Devon and, to a lesser extent, the acreage dedications with and successful drilling by other producers.

Items Affecting Comparability of Midstream Holdings Financial Results

The historical financial results of the Predecessor discussed below may not be comparable to Midstream Holdings future financial results for the following reasons:

- The Predecessor s historical assets comprised all of Devon s U.S. midstream assets and operations. However, only its assets serving the Barnett, Cana-Woodford and Arkoma-Woodford Shales, as well as the 38.75% economic interest in Gulf Coast Fractionators, were contributed to Midstream Holdings in connection with the consummation of the Merger. These assets generated approximately 96% of the Predecessor s net income from continuing operations for year ended December 31, 2013.

- Midstream Holdings has entered into new agreements with Devon pursuant to which Midstream Holdings provides services under fixed-fee arrangements and no longer takes title to the natural gas gathered and processed or the NGLs it fractionates.

- The Predecessor s historical combined financial statements include U.S. federal and state income tax expense. Due to Midstream Holdings status as a partnership, the 50% interest in Midstream Holdings that is owned directly by the Partnership will not be subject to U.S. federal income tax and certain state income taxes in the future.

- All historical affiliated transactions related to Midstream Holdings continuing operations were net settled within its combined financial statements because these transactions related to Devon and were funded by Devon s working capital. In the future, all of Midstream Holdings transactions will be funded by its working capital. This will impact the comparability of its cash flow statements, working capital analysis and liquidity discussion.

General Trends and Outlook

Natural Gas and NGL Supply and Demand

Midstream Holdings gathering and processing operations are generally dependent upon natural gas production from Devon s upstream activity in its areas of operation. The significant decline in natural gas prices as a result of significant new supplies of domestic natural gas production has caused a related decrease in dry natural gas drilling by many producers in the United States. Depressed oil and natural gas prices could affect production rates over time and levels of investment by Devon and third parties in exploration for and development of new oil and natural gas reserves. In addition, there is a natural decline in production from existing wells that are connected to Midstream Holdings gathering systems. Midstream Holdings believes Devon s five-year minimum volume commitments substantially reduce Midstream Holdings volumetric risk over that period of time. After the expiration of these five-year minimum volume commitments, a material decline in the volume of natural gas that Midstream Holdings gathers and transports on its systems would result in a material decline in its total operating revenues and cash flows. Although Midstream Holdings expects that Devon will continue to devote substantial resources to the development of the Barnett and Cana-Woodford Shales, it has no control over this activity and Devon has the ability to reduce or curtail such development at its discretion.

Rising Operating Costs and Inflation

The current level of exploration, development and production activities across the United States has resulted in increased competition for personnel and equipment. This competition has caused, and Midstream Holdings believes it will continue to cause, increases in the prices it pays for labor, supplies and property, plant and equipment. An increase in the general level of prices in the economy could have a similar effect on the operating costs Midstream Holdings incurs. Midstream Holdings will

Table of Contents

attempt to recover increased costs from its customers, but there may be a delay in doing so or it may be unable to recover all these costs. To the extent Midstream Holdings is unable to procure necessary supplies or recover higher costs, its operating results will be negatively impacted.

Regulatory Compliance

The regulation of natural gas gathering and transportation activities by FERC and other federal and state regulatory agencies, including the DOT, has a significant impact on Midstream Holdings business. For example, PHMSA has established pipeline integrity management programs that require more frequent inspections of pipeline facilities and other preventative measures, which may increase Midstream Holdings 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 Midstream Holdings gathering systems.

Results of Predecessor s Operations

The following schedule presents the Predecessor s historical combined key operating and financial metrics.

	Year Ended December 31, ($ in millions, except prices)		
	2013	2012	2011
Operating revenues	$ 2,390.7	$ 2,000.8	$ 2,623.4
Product purchases	(1,773.7)	(1,464.5)	(2,014.1)
Operations and maintenance expenses	(170.7)	(171.0)	(155.5)
Operating margin	446.3	365.3	453.8
Other operating expenses, net	(282.7)	(263.7)	(142.2)
Income from equity investment	14.8	2.0	9.3
Income tax expense	(64.2)	(37.3)	(115.5)
Net income from continuing operations	114.2	66.3	205.4
Net income from discontinued operations	1.3	9.5	10.7
Net income attributable to Devon	$ 115.5	$ 75.8	$ 216.1
Throughput (thousands of MMBtu/d):			
Bridgeport rich gathering system	861.1	818.4	811.6
Bridgeport lean gathering system	261.8	298.0	296.0
Acacia transmission system	741.8	732.7	700.1
East Johnson County gathering system	236.8	277.8	258.0
Barnett assets	2,101.5	2,126.9	2,065.7
Cana gathering system	320.7	265.7	175.7
Northridge gathering system	69.2	85.0	109.5
Other systems	217.0	243.0	286.5
Total	2,708.4	2,720.6	2,637.4
NGL production (MBbls/d):			
Bridgeport processing facility	58.9	49.4	52.8
Cana processing facility	18.8	12.1	3.9
Northridge processing facility	8.2	6.8	10.5
Other systems	2.7	2.7	2.5

Total	88.6	71.0	69.7
Residue natural gas production (thousands of MMBtu/d):			
Bridgeport processing facility	623.1	613.1	599.5
Cana processing facility	242.1	209.7	151.5
Northridge processing facility	52.2	65.5	85.3
Other systems	7.4	7.4	2.6
Total	924.8	895.7	838.9
Realized prices:			
NGLs ($/Bbl)	$ 30.05	$ 35.38	$ 49.16
Residue natural gas ($/MMBtu)	$ 3.18	$ 2.38	$ 3.58

Since 2011, operating margin has consistently improved as a result of production growth. The largest contributors to rising production have been Midstream Holdings Cana, Bridgeport rich, and Acacia systems, with daily throughput growth of 83%, 6%, and 6%, respectively, from 2011 to 2013. This growth is the result of Devon and other producers developing liquids-rich natural gas production in the Cana-Woodford and Barnett Shales. However, overall growth has been limited by throughput declines for the Predecessor s other systems, which are the result of natural gas price decreases. As natural gas prices have dropped relative to oil and NGL prices in recent years, many producers, including Devon, have focused on growing their oil and liquids-rich natural gas production rather than dry natural gas. Consequently, Midstream Holdings systems serving liquids-rich natural gas regions in the Cana-Woodford and Barnett Shales have higher throughput, while Midstream Holdings systems serving dry natural gas regions have experienced throughput declines.

Prices have also impacted operating margin. Since 2011, NGL prices have declined significantly, which has negatively impacted operating margin. Natural gas prices have been volatile, increasing in 2013 after a significant decline in 2012.

Table of Contents

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Operating Margin

Operating margin increased $81.0 million, or 22%, from the year ended December 31, 2012 to the year ended December 31, 2013, as summarized in the following schedule:

		(in millions)
Operating margin, 2012	$	365.3
Change due to volumes		32.3
Change due to pricing		48.4
Change due to operations and maintenance expenses		0.3
Operating margin, 2013	$	446.3

Higher gathering, processing and transportation volumes were responsible for an increase in operating margin of $32.3 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Higher volumes were primarily the result of NGL production increasing 25%, resulting in $34.1 million of higher operating margin. The increase in NGL production was largely driven by higher inlet volumes at the Cana processing facility, improved efficiencies at the Cana and Bridgeport processing facilities and unplanned downtime impacting Midstream Holdings Bridgeport processing facility in 2012. The increase in NGL production was partially offset by slightly lower throughput volumes, primarily on the Predecessor s East Johnson and Northridge gathering systems.

Changes in pricing led to an increase in operating margin of $48.4 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Natural gas pipeline fees increased 15 %, which resulted in $44.2 million of additional revenues. Additionally, higher residue natural gas prices contributed an additional $32.4 million to operating margin. These increases were partially offset by lower margins of $28.2 million primarily due to NGL price declines.

Operations and maintenance expenses decreased $0.3 million, or 0%.

Other Operating Expenses, Net

Other operating expenses, net increased $19.0 million, or 7%, from the year ended December 31, 2012 to the year ended December 31, 2013, as summarized in the following schedule:

		2013		2012 (in millions)		Change
Depreciation and amortization	$	199.0	$	159.8	$	39.2

General and administrative	47.0	43.6	3.4
Non-income taxes	18.0	13.2	4.8
Asset impairments	18.2	50.1	(31.9)
Other, net	0.5	(3.0)	3.5
Other operating expenses, net	$ 282.7	$ 263.7	$ 19.0

Depreciation and amortization expense increased $39.2 million, or 25%, from 2012 to 2013. The increase primarily resulted from higher capitalized costs on the Cana system. Devon and other producers have continued to grow natural gas production in the Cana-Woodford Shale. As a result, we have increased our throughput capacity by expanding our pipeline and gathering systems and our Cana processing facility.

Historical general and administrative expenses consist of costs allocated by Devon for shared services that consist primarily of accounting, treasury, information technology, human resources, legal and facilities management. The costs were allocated based on a proportionate share of Devon s revenues, employee compensation and gross property, plant and equipment.

General and administrative expense increased $3.4 million, or 8%, primarily due to higher employee compensation and benefits.

Non-income tax expense consists primarily of ad valorem taxes. Non-income taxes increased $4.8 million, or 36%, from 2012 to 2013 primarily due to higher ad valorem tax assessments on Midstream Holdings Cana assets.

In 2013 and 2012, Devon recognized asset impairments of $18.2 million and $50.1 million, respectively. Devon determined that the carrying amounts of certain midstream facilities located in south and east Texas were not recoverable from estimated future cash flows due to declining dry natural gas production. Consequently, the assets were written down to their estimated fair values, which were determined using discounted cash flows. None of the asset impairments in 2013 were related to assets that were contributed to Midstream Holdings.

During 2013 and 2012, our Predecessor recognized $0.5 million of net other expense and $3.0 million of net other income, respectively. In the second quarter of 2012, Predecessor received insurance proceeds of $5.6 million related to business interruption that occurred at Gulf Coast Fractionators.

Table of Contents

Income Tax Expense. During 2013 and 2012, effective income tax rates were 36% for both periods. These rates differed from the U.S. statutory income tax rate due to the effect of state income taxes.

Discontinued Operations. The Predecessor has sold certain non-core assets that are presented as discontinued operations in the Predecessor s historical financial statements. Net income from discontinued operations decreased $8.2 million from 2012 to 2013. The decrease was primarily due to the gain recognized on the divestiture of the West Johnson County processing facility and gathering system in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Operating Margin. Operating margin decreased $88.5 million, or 20%, from the year ended December 31, 2011 to the year ended December 31, 2012, as summarized in the following schedule:

		(in millions)
Operating margin, 2011	$	453.8
Change due to volumes		20.8
Change due to pricing		(93.8)
Change due to operations and maintenance expenses		(15.5)
Operating margin, 2012	$	365.3

Higher gathering, processing and transportation volumes were responsible for an increase in operating margin of $20.8 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. Residue volumes increased 7%, resulting in a $9.1 million increase to operating margin. The remainder of the operating margin increase resulted from higher natural gas gathered volumes and NGL production, which increased 3% and 2%, respectively. These volume increases primarily resulted from the restart of Midstream Holdings Cana processing facility following tornado damage in 2011, higher volumes on Midstream Holdings East Johnson County gathering system and continued development of the liquids-rich areas in the Cana-Woodford and Barnett Shales.

Changes in pricing led to a decrease in operating margin of $93.8 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. Lower NGL and residue natural gas prices reduced operating margin by $71.0 million and $42.8 million, respectively. These decreases were partially offset by higher gathering and compression fees which increased $20.0 million, or 9%.

Operations and maintenance expenses increased $15.5 million, or 10%, partially due to higher volumes, including the Cana system expansion. Expenses also increased due to repair and testing activities that were required on Midstream Holdings Bridgeport gathering systems in 2012.

Other Operating Expenses, Net. Other operating expenses, net increased $121.5 million, or 85%, from the year ended December 31, 2011 to the year ended December 31, 2012, as summarized in the following schedule:

	2012	2011	Change
		(in millions)	
Depreciation and amortization	$ 159.8	$ 144.8	$ 15.0
General and administrative	43.6	40.1	3.5
Non-income taxes	13.2	15.3	(2.1)
Asset impairments	50.1		50.1
Other, net	(3.0)	(58.0)	55.0
Other operating expenses, net	$ 263.7	$ 142.2	$ 121.5

Depreciation and amortization expense increased $15.0 million, or 10%, from 2011 to 2012. The increase primarily resulted from higher capitalized costs on the Cana system. Devon and other producers have continued to grow natural gas production in the Cana-Woodford Shale. As a result, Midstream Holdings increased throughput capacity by expanding its pipeline and gathering systems and our Cana processing facility.

Historical general and administrative expenses consist of costs allocated by Devon for shared services that consist primarily of accounting, treasury, information technology, human resources, legal and facilities management. The costs were allocated based on a proportionate share of Devon s revenues, employee compensation and gross property, plant and equipment.

General and administrative expense increased $3.5 million, or 9%, from 2011 to 2012, primarily due to higher employee compensation and benefits.

Non-income tax expense consists primarily of ad valorem taxes. Non-income taxes decreased $2.1 million, or 14%, from 2011 to 2012 primarily due to lower ad valorem tax assessments on Midstream Holdings Barnett assets.

Table of Contents

The following schedule summarizes asset impairments recognized in 2012. There were no asset impairments in 2011. Due to declining natural gas production resulting from low natural gas and NGL prices, Midstream Holdings determined that the carrying amounts of certain of the Predecessors midstream assets, including the Northridge system, were not recoverable from estimated future cash flows. Consequently, the Northridge system and other assets of the Predecessor were written down to their estimated fair values, which were determined using discounted cash flow models.

		2012 (in millions)
Northridge	$	16.4
Other assets not being contributed to Midstream Holdings		33.7
Total asset impairments	$	50.1

During 2012 and 2011, the Predecessor recognized $3.0 million and $58.0 million of net other income, respectively. In 2012, the Predecessor received insurance proceeds of $5.6 million related to business interruption that occurred at Gulf Coast Fractionators. In 2011, the Predecessor received $57.8 million of excess insurance recoveries related to business interruption and equipment damage at the Cana system that resulted from tornadoes.

Income Tax Expense. During 2012 and 2011, Midstream Holdings effective income tax rates were 36% for both periods. These rates differed from the U.S. statutory income tax rate due to the effect of state income taxes.

Discontinued Operations. Net income from discontinued operations decreased $1.2 million from 2011 to 2012. The decrease was due to lower operating earnings subsequent to the divestiture of the West Johnson County processing facility and gathering system in 2012, partially offset by the $8.3 million gain recognized on the divestiture.

Midstream Holdings Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires Midstream Holdings to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from these estimates, and changes in these estimates are recorded when known. Changes in these estimates can have a material effect on the financial statements.

The critical accounting policies used by management in the preparation of Midstream Holdings combined financial statements are those that require significant judgments by management with regard to estimates used and are important both to the presentation of its financial condition and results of operations. Midstream Holdings critical accounting policies and significant judgments and estimates related to those policies are described below.

Allocation of Devon Corporate Overhead Costs

Certain of Devon s centralized overhead and operating costs are incurred for the benefit of its subsidiaries and affiliates, including Midstream Holdings. As a result, a portion of such costs are allocated to Midstream Holdings operations. The portion of such costs that directly benefits Midstream Holdings operations is allocated entirely to Midstream Holdings. The remaining portion of costs that benefits Midstream Holdings and other Devon affiliates is allocated using a three-factor formula. This formula uses an equal weighting of revenues, employee compensation and gross property, plant and equipment balances to determine amounts to be allocated to Midstream Holdings and other Devon affiliates.

These cost allocations are affected by the amount of costs Devon incurs for its centralized overhead and operating activities and the allocation methodologies chosen. Determining the amount of costs Devon incurs for its centralized overhead and operating activities generally does not require significant judgment by management because such costs are readily identifiable. Although there are a number of alternative methodologies for allocating Devon s centralized overhead and operating costs, management believes the allocation methodologies used are based on assumptions that are reasonable. However, if certain costs were allocated using different methodologies, Midstream Holdings profitability and financial condition could change significantly.

Depreciation of Property, Plant and Equipment

Midstream Holdings depreciation calculations include estimates of salvage value and useful lives. As estimates of salvage values decrease, the amount of depreciation recognized in successive periods and over the estimated useful life of PP&E increases. Midstream Holdings estimates salvage values to be near zero at the end of the asset s useful life.

Similar to salvage value estimates, as estimates of useful lives decrease, the amount of depreciation recognized in successive periods increases. However, useful life estimates have no impact on the amount of depreciation recognized over the life of PP&E. For assets subject to the straight-line method of calculating depreciation, Midstream Holdings utilizes estimated useful lives ranging from three to 25 years. These estimates are based on the historical usage of similar assets.

For assets subject to the units-of-production basis of calculating depreciation, useful lives are estimated based on proved oil, natural gas and NGL reserve estimates from the fields being serviced by those assets. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, natural gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. However, based on historical experience, such differences are not expected to be material.

Table of Contents

Impairment of Property, Plant & Equipment

Midstream Holdings evaluates Property, Plant & Equipment (PP&E) for potential impairment annually and more frequently when events or changes in circumstances indicate that the carrying amount of Midstream Holdings PP&E may not be recoverable from estimated future cash flows.

Midstream Holdings determines PP&E fair values from estimated discounted future net cash flows. The estimated cash flows can be significantly affected by the inputs used in the calculations, such as future throughput volumes, natural gas and NGL prices, operating costs, useful lives and discount rates. Different assumptions and judgments could be used to determine the cash flow inputs. There are also alternative valuation techniques that could be used to estimate fair value.

There are a number of inter-related inputs that can affect discounted cash flows. Due to the number of inter-related inputs, it is impractical to provide specific quantitative analyses of potential changes in these estimates. However, general analyses can be provided for the most significant inputs which include current and projected throughput and current and projected natural gas and NGL prices. As such inputs decrease, the cash flows will generally change in a like manner and would increase the likelihood of a PP&E impairment charge.

A PP&E impairment would have no direct effect on Midstream Holdings operating margin or liquidity. However, it would adversely affect Midstream Holdings net income.

Goodwill Valuation

Midstream Holdings has one reporting unit with goodwill, which requires management to estimate the fair value of the reporting unit and evaluate goodwill for potential impairment. Midstream Holdings tests goodwill annually in the fourth quarter of each year and more frequently when an event occurs or circumstances change that would more likely than not reduce the fair value of Midstream Holdings reporting unit below its carrying amount.

Because quoted market prices are not available for Midstream Holdings reporting unit, Midstream Holdings estimates its fair value using valuation analyses based on values of comparable companies and comparable transactions. In a comparable companies analysis, Midstream Holdings reviews the public stock market trading multiples for selected publicly-traded midstream companies with comparable financial and operating characteristics. These characteristics are market capitalization, location of midstream operations and the characterization of such operations that are deemed to be similar to ours. In a comparable transactions analysis, Midstream Holdings reviews certain acquisition multiples for selected recent midstream company or asset package transactions.

The fair value of Midstream Holdings reporting unit is then estimated by applying the average multiple determined from the two valuation techniques described above to current year projected cash flow. As these valuation multiples decrease, the estimated fair value of the reporting unit would decrease. As a result, the likelihood of a goodwill impairment charge would increase.

There are a number of inter-related inputs which can affect the valuation multiples. Due to the number of inter-related inputs, it is impractical to provide specific quantitative analyses of potential changes in these estimates. However, general analyses can be provided for the most significant inputs which include current and projected throughput and current and projected natural gas and NGL prices. As such inputs decrease, the trading multiples will generally change in a like manner and would increase the likelihood of a goodwill impairment charge.

A goodwill impairment would have no direct effect on Midstream Holdings operating margin or liquidity. However, it would adversely affect Midstream Holdings net income.

Liquidity and Capital Resources

Midstream Holdings Sources and Uses of Cash

The following schedule presents Midstream Holdings sources and uses of cash:

	Year Ended December 31, 2013	2012	2011
Continuing operations:			
Operating cash flow	$ 360.5	$ 254.4	$ 401.2
Capital expenditures	(243.1)	(351.7)	(247.6)
Contributions from (distributions to) owners	(117.6)	115.7	(131.1)
Other, net	0.2	(18.4)	(22.5)
Net change in cash			
Discontinued operations:			
Operating cash flow	1.8	25.3	33.4
Divestiture proceeds	155.1	87.6	
Capital expenditures	(2.1)	(13.5)	(22.5)
Contributions from (distributions to) owners	(170.4)	(91.9)	(34.8)
Net change in cash	(15.6)	7.5	(23.9)
Total change in cash	$ (15.6)	$ 7.5	$ (23.9)

Table of Contents

Midstream Holdings Sources and Uses of Cash Continuing Operations. Operating cash flow has been a significant source of liquidity. Generally, operating cash flow will increase or decrease due to the same factors that cause increases and decreases in operating margin. Consequently, changes in operating cash flow since 2011 are primarily driven by the fluctuations in volume and price described previously in results of operations.

Historically, operating cash flow has been used to fund capital expenditures. Since 2011, the Predecessor completed several capital expansion activities, including the expansions of the Cana system and Barnett assets in 2013.

Because Midstream Holdings continuing operations had no separate cash accounts, the owner contributions and distributions represent the net amount of all transactions that were settled with adjustments to equity.

Other, net uses and sources since 2011 largely pertain to the Predecessor s equity investment in Gulf Coast Fractionators. During the years ended December 31, 2012 and 2011, the Predecessor made contributions related to this investment of $16.8 million and $21.1 million, respectively.

Midstream Holdings Sources and Uses of Cash Discontinued Operations. Operating cash flow has decreased since 2011 largely due to declining throughput resulting from asset divestitures. In 2013, the Predecessor sold its controlling interest in its assets and operations located in Wyoming for approximately $148 million. In 2012, the Predecessor sold the West Johnson County system for $87 million. The Predecessor also received proceeds in 2013 and 2010 for other minor divestitures. These divestitures also contributed to the general decline in capital expenditures since 2011.

During the years ended 2013 and 2011, the Predecessor made cash distributions to non-controlling interests of $2.9 million, $5.4 million, respectively. During the year ended 2012, the Predecessor received cash contributions from non-controlling interests of $2.3 million, respectively. The remaining owner contributions and distributions in the table above represent the net amount of all other transactions that were settled with adjustments to equity.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2013, 2012 and 2011.

Contractual Obligations

A summary of Midstream Holdings contractual obligations as of December 31, 2013 is provided in the following table:

		Payments Due by Period			
		Less Than	1-3	3-5	More Than
	Total	1 Year	Years	Years	5 Years

			(in millions)		
Lease obligations (1)	$ 8.1	$ 7.4	$ 0.7	$	$
Rights-of-way (2)	1.0	0.1	0.2	0.2	0.5
Purchase commitments (3)	3.9	3.9			
Asset retirement obligations (4)	14.9	0.1	0.1	0.1	14.6
Total	$ 28.0	$ 11.6	$ 1.0	$ 0.3	$ 15.1

(1) Lease obligations consist of non-cancelable operating leases for equipment and office space used in daily operations.

(2) Right-of-way payments are estimated to approximate $0.1 million per year for the next ten years. Payments for rights-of-way will be required as long as Midstream Holdings systems are in use, which may be more or less than the ten years we have assumed for this disclosure.

(3) Purchase commitments include commitments to purchase materials in connection with Midstream Holdings projects to construct new facilities or expand existing facilities.

(4) Asset retirement obligations represent the estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on Midstream Holdings December 31, 2013 balance sheet.

Table of Contents

Capital Requirements

The 2014 capital budget includes the Partnership s budgeted capital spend of approximately $300.0 million of identified growth projects including capitalized interest, and the Company s budgeted capital spend for our E2 investment of approximately $30.0 million to $36.0 million. The Partnership s primary capital projects for 2014 include the expansion of the Cajun-Sibon NGL Pipeline Phase II and construction of its Bearkat plant facilities. During 2013, the Partnership invested in several capital projects which primarily included the expansion of the Cajun-Sibon NGL Pipeline. See Item 1. Business Recent Growth Developments for further details.

We and the Partnership expect to fund our maintenance capital expenditures of approximately $37.5 million and $57.5 million, respectively, from operating cash flows. We and the Partnership expect to fund the growth capital expenditures from the proceeds of borrowings under our credit facility and the Partnership s bank credit facility discussed below, respectively, and proceeds from other debt and equity sources. In 2014, it is possible that not all of the planned projects will be commenced or completed. The Midstream Entities ability to pay distributions to their equityholders, and to fund planned capital expenditures and to make acquisitions, will depend upon their future operating performance, which will be affected by prevailing economic conditions in the industry and financial, business and other factors, some of which are beyond their control.

Indebtedness

Company Credit Facility. On March 7, 2014, we entered into a new $250.0 million revolving credit facility, which includes a $125.0 million letter of credit subfacility (the credit facility). We used borrowings under the credit facility to repay outstanding borrowings under the margin loan facility of XTXI Capital, LLC (a former wholly-owned subsidiary of EnLink Midstream, Inc.), which was paid in full and terminated on March 7, 2014. Our obligations under the credit facility are guaranteed by our two wholly-owned subsidiaries and secured by first priority liens on (i) 16,414,830 Partnership common units and the 100% membership interest in the General Partner indirectly held by us, (ii) the 100% equity interest in each of our wholly-owned subsidiaries held by us, (iii) the 50% limited partner interest in Midstream Holdings held by us and (iv) any additional equity interests subsequently pledged as collateral under the credit facility. All such guarantees, liens and security interests will be released after the occurrence of an investment grade event (as defined in the credit facility).

The credit facility will mature on March 7, 2019. The credit facility contains certain financial, operational and legal covenants. The financial covenants will be tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter, and include (i) maintaining a maximum consolidated leverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated funded indebtedness to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) of 4.00 to 1.00, provided that the maximum consolidated leverage ratio is 4.50 to 1.00 during an acquisition period (as defined in the credit facility) and (ii) maintaining a minimum consolidated interest coverage ratio (as defined in the credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) of 2.50 to 1.00 at all times prior to the occurrence of an investment grade event (as defined in the credit facility).

Borrowings under the credit facility bear interest, at our option, at either the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent s prime rate) plus an applicable margin. The applicable margins vary depending on our leverage ratio. Upon breach by us of certain covenants governing the credit facility, amounts outstanding under the credit facility, if any, may become due and payable immediately and the liens securing credit facility could be foreclosed upon.

Partnership Credit Facility. On February 20, 2014, the Partnership entered into a new $1.0 billion unsecured revolving credit facility, which includes a $500.0 million letter of credit subfacility (the Partnership credit facility). The new Partnership credit facility replaced the Partnership s previous credit facility. The Partnership credit facility will mature on the fifth anniversary of the initial funding date, which was March 7, 2014, unless the Partnership requests, and the requisite lenders agree, to extend it pursuant to its terms. The Partnership credit facility contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the Partnership credit facility, which definition includes projected EBITDA from certain capital expansion projects) of no more than 5.0 to 1.0. If the Partnership consummates one or more acquisitions in which the aggregate purchase price is $50.0 million or more, the maximum allowed ratio of consolidated indebtedness to consolidated EBITDA will increase to 5.5 to 1.0 for the quarter of the acquisition and the three following quarters.

Borrowings under the Partnership credit facility bear interest at the Partnership s option at the Eurodollar Rate (the LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent s prime rate) plus an applicable margin. The applicable margins vary depending on the Partnership s credit rating. Upon breach by the Partnership of certain covenants governing the Partnership credit facility, amounts outstanding under the Partnership credit facility, if any, may become due and payable immediately.

Other Borrowings. On September 4, 2013, E2 Energy Services LLC, (E2 Services), one of the Ohio services companies in which the Company invests, entered into a credit agreement with JPMorgan Chase Bank (JPMorgan). The maturity date of the credit agreement is September 4, 2016. As of December 31, 2013, there was $12.7 million borrowed under the agreement,

Table of Contents

leaving approximately $7.3 million available for future borrowing based on borrowing capacity of $20.0 million. The interest rate under the credit agreement is based on Prime plus an applicable margin. The effective interest rate as of December 31, 2013 was approximately 4.2%. Additionally, as of December 31, 2013, E2 Services had certain promissory notes outstanding relating to its vehicle fleet in the amount of $0.5 million due in increments through July 2017. The notes bear interest at fixed rates ranging 3.9% to 7.0%. We do not guarantee E2 Services debt obligations.

Senior Unsecured Notes. On February 10, 2010, the Partnership issued, together with EnLink Midstream Finance Corporation (formerly known as Crosstex Energy Finance Corporation), $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the 2018 Notes) due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity including the original issue discount (OID). Interest payments on the 2018 Notes are due semi-annually in arrears in February and August. The Partnership repurchased approximately 74% of its 2018 Notes pursuant to a tender offer, as described below. On May 24, 2012, the Partnership issued, together with EnLink Midstream Finance Corporation, $250.0 million in aggregate principal amount of 7.125% senior unsecured notes (the 2022 Notes) due on June 1, 2022 at an issue price of 100% of the principal amount to yield 7.125% to maturity. The interest payments on the 2022 Notes are due semi-annually in arrears in June and December. The Partnership has redeemed approximately 21% of its 2022 Notes, as described below. On March 19, 2014, the Partnership issued $1.2 billion aggregate principal amount of unsecured senior notes, consisting of $400.0 million aggregate principal amount of its 2.700% senior notes due 2019 (the 2019 Notes), $450.0 million aggregate principal amount of its 4.400% senior notes due 2024 (the 2024 Notes) and $350.0 million aggregate principal amount of its 5.600% senior notes due 2044 (the 2044 Notes and, together with the 2018 Notes, 2019 Notes, 2022 Notes and 2024 Notes, the Senior Notes), at prices to the public of 99.850%, 99.830% and 99.925%, respectively, of their face value. The 2019 Notes mature on April 1, 2019, the 2024 Notes mature on April 1, 2024 and the 2044 Notes mature on April 1, 2044. The interest payments on the 2019 Notes, 2024 Notes and 2044 Notes are due semi-annually in arrears in April and October.

Successful completion of the business combination triggered a mandatory repurchase offer under the terms of the indenture governing the 2018 Notes at a purchase price equal to 101% of the aggregate principal amount of the 2018 Notes repurchased, plus accrued and unpaid interest, if any. To fulfill its obligations with respect to the mandatory repurchase offer of the 2018 Notes, on March 12, 2014, the Partnership commenced a tender offer to purchase any and all of the outstanding 2018 Notes. Approximately $536.1 million, or approximately 74%, of the 2018 Notes were validly tendered and not withdrawn prior to the expiration of the tender offer, and on March 19, 2014, the Partnership and made payment of approximately $567.4 million for all such tendered 2018 Notes. Also on March 19, 2014, the Partnership instructed the trustee to deliver a notice of redemption for any and all outstanding 2018 Notes for a total redemption price equal to $1,059.91 per $1,000 principal amount redeemed. The redemption date for the 2018 Notes is April 18, 2014.

The Partnership may redeem up to 35% of the 2022 Notes at any time prior to June 1, 2015 in an amount not greater than the cash proceeds from one or more equity offerings at a redemption price of 107.125% of the principal amount of the 2022 Notes (plus accrued and unpaid interest to the redemption date) provided that

- at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding immediately after the occurrence of such redemption; and

- the redemption occurs within 180 days of the date of the closing of the equity offering.

Pursuant to the foregoing, on January 3, 2014, the Partnership instructed the trustee to deliver a notice of redemption for approximately $53.5 million in aggregate principal amount of the 2022 Notes (the Redeemed Notes), representing approximately 21% of the aggregate principal amount of the outstanding 2022 Notes. The Redeemed Notes were redeemed effective as of February 2, 2014 for a total redemption price equal to $1,083 per $1,000 principal amount redeemed. Following the completion of the redemption, approximately $196.5 million aggregate principal amount of the 2022 Notes remain outstanding.

Prior to June 1, 2017, the Partnership may redeem all or a part of the remaining 2022 Notes at the redemption price equal to the sum of the principal amount thereof, plus a make-whole premium at the redemption date, plus accrued and unpaid interest to the redemption date.

On or after June 1, 2017, the Partnership may redeem all or a part of the remaining 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.563% for the twelve-month period beginning on June 1, 2017, 102.375% for the twelve-month period beginning on June 1, 2018, 101.188% for the twelve-month period beginning on June 1, 2019 and 100.000% for the twelve-month period beginning on June 1, 2020 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

If, within 90 days of consummation of the business combination, the Partnership had experienced a rating downgrade of the 2022 Notes by either Moody s or S&P, the business combination would have also triggered a mandatory repurchase offer under the terms of the indenture governing the 2022 Notes. However, following the business combination, the Partnership experienced a rating upgrade by both Moody s and S&P.

Table of Contents

Prior to March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2019 Notes to be redeemed; or (ii) the sum of the remaining scheduled payments of principal and interest on the 2019 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 20 basis points; plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after March 1, 2019, the Partnership may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2024 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2024 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 25 basis points; plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after January 1, 2024, the Partnership may redeem all or a part of the 2024 Notes at a redemption price equal to 100% of the principal amount of the 2024 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Prior to October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to the greater of: (i) 100% of the principal amount of the 2044 Notes to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2044 Notes to be redeemed that would be due after the related redemption date but for such redemption (exclusive of interest accrued to, but excluding, the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the applicable Treasury Rate plus 30 basis points; plus, in either case, accrued and unpaid interest to, but excluding, the redemption date.

At any time on or after October 1, 2043, the Partnership may redeem all or a part of the 2044 Notes at a redemption price equal to 100% of the principal amount of the 2044 Notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

The indentures governing the Senior Notes contain covenants that, among other things, limit our ability to create or incur certain liens or consolidate, merger or transfer all or substantially all of our assets.

Each of the following is an event of default under the indentures:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation or other covenant in the indenture, subject to the cure periods for certain failures;
- our default under other indebtedness that exceeds a certain threshold amount;
- failures by us to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving us.

If an event of default relating to bankruptcy or other insolvency events occurs, the Senior Notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the Senior Notes may accelerate the maturity of the Senior Notes and exercise other rights and remedies.

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws that are based on information currently available to management as well as management s assumptions and beliefs. All statements, other than statements of historical fact, included in this Form 10-K constitute forward-looking statements, including but not limited to statements identified by the words forecast, may, believe, will, should, plan, predict, anticipate, intend, estimate and expect and similar expressions. Such stat current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Form 10-K, the risk factors set forth in Item 1A. Risk Factors may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Table of Contents

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

Because of the new fixed-fee arrangements Midstream Holdings entered into with Devon in conjunction with the mergers, pursuant to which it does not take title to natural gas gathered, processed and transported, it bears almost no commodity price risk with respect to its future contractual arrangements. After the expiration of the five-year minimum volume commitments, Midstream Holdings will have indirect exposure to commodity price risk in that persistently low commodity prices may cause Devon to delay drilling or shut-in production, which would reduce throughput on Midstream Holdings assets.

Item 8. ***Financial Statements and Supplementary Data***

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-14 of this Report and are incorporated herein by reference.

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

None.

Item 9A. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (December 31, 2013), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the year ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

(c) Management s Report of Internal Control Over Financial Reporting

This Annual Report on Form 10-K does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by the rules of the Commission for newly public companies.

Item 9B. ***Other Information***

None.

Table of Contents

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The following table shows information about the executive officers and board of directors (the Board) of EnLink Midstream Manager, LLC, our managing member (the Managing Member). Executive officers serve until their successors are elected or appointed.

Name	Age	Position with the Managing Member
Barry E. Davis(1)	52	President and Chief Executive Officer
Joe A. Davis(1)	53	Executive Vice President, General Counsel and Secretary
Michael J. Garberding	45	Executive Vice President and Chief Financial Officer
Steve J. Hoppe	51	Executive Vice President and President of Gas Gathering, Processing and Transmission
McMillan (Mac) Hummel	51	Executive Vice President and President of Natural Gas Liquids and Crude
John Richels	62	Chairman of the Board
Thomas L. Mitchell	53	Director
David A. Hager	57	Director and Member of the Governance and Compensation Committee
Darryl G. Smette	66	Director
Mary P. Ricciardello**	58	Director and Member of the Audit Committee
James C. Crain**	65	Director and Member of the Audit Committee
Leldon E. Echols**	58	Director and Member of Audit* Committee
Rolf A. Gafvert**	60	Director and Member of the Conflicts and Governance and Compensation* Committees

* Denotes chairman of committee.

** Denotes independent director.

(1) Not related.

Barry E. Davis is the President and Chief Executive Officer and a Director of the Managing Member. Mr. Davis led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of the Partnership s predecessor. Mr. Davis has served as director of the General Partner since the Partnership s initial public offering in December 2002 and as a director of Crosstex Energy, Inc. since its initial public offering in January 2004. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis was appointed to the Board pursuant to the terms of the Merger Agreement and due to his leadership skills and experience in the midstream natural gas industry, among other factors.

Joe A. Davis is the Executive Vice President, General Counsel and Secretary of the Managing Member. Mr. Davis previously joined Crosstex Energy, Inc. in October 2005. He began his legal career in 1985 with the Dallas firm of Worsham Forsythe, which merged with the international law firm of Hunton & Williams in 2002. Most recently, he served as a partner in the firm s Energy Practice Group, and served on the firm s Executive Committee. Mr. Davis specialized in facility development, sales, acquisitions and financing for the energy industry, representing entrepreneurial start up/development companies, growth companies, large public corporations and large electric and gas utilities. He received his J.D. from Baylor Law School in Waco and his B.S. degree from the University of Texas in Dallas.

Michael J. Garberding is the Executive Vice President and Chief Financial Officer of the Managing Member. Mr. Garberding previously joined Crosstex Energy, Inc. in February 2008. Mr. Garberding assumed the role of Senior Vice President and Chief Financial Officer of the Corporation in August 2011 and the role of Executive Vice President and Chief Financial Officer of Crosstex Energy, Inc. in January 2013. Mr. Garberding previously led the finance and business development organization for Crosstex Energy, L.P. Mr. Garberding has 20 years experience in finance and accounting. From 2002 to 2008, Mr. Garberding held various finance and business development positions at TXU Corporation, including assistant treasurer. In addition, Mr. Garberding worked at Enron North America as a Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Masters in Business Administration from the University of Michigan in 1999 and his B.B.A. in Accounting from Texas A&M University in 1991.

Steve J. Hoppe is the Executive Vice President and President of Gas Gathering, Processing and Transmission of the Managing Member. Previously, Mr. Hoppe served as Senior Vice President of Midstream Operations for Devon, which he joined in 2007. Mr. Hoppe has more than 25 years of midstream energy-industry experience, including eight years at Thunder Creek Gas Services, where he most recently served as President. Mr. Hoppe holds a Bachelor of Science degree in civil engineering from the University of Wyoming.

Table of Contents

McMillan (Mac) Hummel is the Executive Vice President and President of Natural Gas Liquids and Crude of the Managing Member. Previously, Mr. Hummel served in various positions with The Williams Companies, which he joined in 1985, including Vice President of Commodity Services, Vice President of Natural Gas Liquids and Olefins and Vice President of Western Region Gathering and Processing. Mr. Hummel began his career with Williams serving as Director of Business Development for the Northwest Pipeline while living in Calgary, Alberta. Mr. Hummel has been a member of the American Fuel & Petrochemical Manufacturers Petrochemical Committee and the Association of Oil Pipe Lines Pipeline Subcommittee. Mr. Hummel earned a Bachelor of Science degree in accounting and a Masters of Business Administration from the University of Utah.

John Richels has been President and Chief Executive Officer of Devon since June 2010. From January 2004 to June 2010, Mr. Richels served as President of Devon. He joined the Board of Directors of Devon in 2007. Prior to 2004, Mr. Richels served as a Senior Vice President of Devon and President and Chief Executive Officer of Devon s Canadian subsidiary. Mr. Richels joined Devon through its 1998 acquisition of Canadian-based Northstar Energy Corp. Prior to joining Northstar, Mr. Richels was Managing and Chief Operating Partner of the Canadian-based national law firm, Bennett Jones. Mr. Richels has served as a director of the Managing Member and the General Partner since March 7, 2014. Mr. Richels also currently serves on the Boards of Devon Energy, TransCanada Corp. and BOK Financial Corporation. He holds a Bachelor of Arts degree in Economics from York University and a law degree from the University of Windsor. Mr. Richels was appointed to the Board pursuant to the terms of the Merger Agreement and due to his extensive knowledge of the energy industry, including his experience with Midstream Holdings assets and operations.

Thomas L. Mitchell has over 30 years of experience in the oil and gas industry and joined Devon as Executive Vice President and Chief Financial Officer in February 2014. Prior to Devon, Mr. Mitchell served on the board of directors and as the Executive Vice President and Chief Financial Officer of Midstates Petroleum Company throughout its initial public offering process. Prior to that, Mr. Mitchell served as Senior Vice President and Chief Financial Officer of Noble Corporation and spent 18 years with Apache Corporation in various financial and commercial roles. Mr. Mitchell has served as a director of the Managing Member and the General Partner since March 7, 2014. He also is a Director on the Board of Hines Global REIT, Inc., a public real estate investment trust managed by Hines Interests, and holds a Bachelor of Science degree in Accounting from Bob Jones University. Mr. Mitchell was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his financial and business expertise.

David A. Hager is the Chief Operating Officer of Devon. He joined Devon in 2009 as Executive Vice President of Exploration and Production. Prior to Devon, Mr. Hager held several positions within Kerr-McGee Corp, most recently as Chief Operating Officer in the period just before its merger with Andarko Petroleum. Mr. Hager has been a Director and Chairman of the Reserves Committee on Devon s Board since 2007 and has served as a Director for Pride International, Inc. Mr. Hager has served as a director of the Managing Member and the General Partner since March 7, 2014. He holds a Bachelor of Science degree in Geophysics from Purdue University and a Master s in Business Administration degree from Southern Methodist University. Mr. Hager was selected to serve as a director due to his affiliation with Devon, his knowledge of the energy business and his business expertise.

Darryl G. Smette has been the Executive Vice President Marketing, Midstream and Supply Chain of Devon since 1999. Prior to joining Devon, he spent 15 years in various marketing roles with Energy Reserves Group Inc. / BHP Petroleum (Americas) Inc. He is involved with the University of Texas Department of Continuing Education as an oil and gas industry instructor. Mr. Smette is also a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. Mr. Smette has served as a director of the Managing Member and the General Partner since March 7, 2014. He also is serving as a Director on the Board of Panhandle Oil & Gas Inc. and holds a Bachelor degree from Minot State University and a Masters in Business Administration degree from Wichita State University. Mr. Smette was selected to serve as a director due to his affiliation with Devon, his knowledge of the midstream business and his business expertise.

Mary P. Ricciardello was Senior Vice President and Chief Accounting Officer at Reliant Energy Inc., a leading independent power producer and marketer until 2002. She began her career with Reliant in 1982 and served in various financial management positions with the company including Comptroller and Vice President. Ms. Ricciardello has served as a director of the Managing Member and the General Partner since March 7, 2014. Ms. Ricciardello also serves on the Board of Directors of Devon Energy, Noble Corporation and Midstates Petroleum Company, and has served on the Board of Directors for US Concrete. Ms. Ricciardello holds a Bachelor of Science degree in Business Administration from the University of South Dakota and a Master s in Business Administration with an emphasis in Finance from the University of Houston. She is a licensed Certified Public Accountant. Ms. Ricciardello was selected to serve as a director due to her qualifications as a financial expert and her extensive experience in the energy industry, corporate finance and tax matters.

Table of Contents

James C. Crain joined Crosstex Energy, Inc. as a director in July 2006 and has served as a director of the Managing Member since March 7, 2014. Mr. Crain retired as president of Marsh Operating Company in July 2013, where he worked since 1984 and currently is a private investor. Prior to Marsh, he was a partner at the law firm of Jenkens & Gilchrist. Mr. Crain also serves on the boards of GeoMet, Inc., and Approach Resources, Inc. Mr. Crain served as a director of the General Partner from December 2005 to August 2008. He graduated from the University of Texas at Austin with a B.B.A. degree, a master of professional accounting and a doctor of jurisprudence. Mr. Crain was selected to serve as a director due to his legal background and his experience in the oil and natural gas industry, among other factors.

Leldon E. Echols joined Crosstex Energy, Inc. as a director in January 2008 and has served as a director of the Managing Member since March 7, 2014. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of Trinity Industries, Inc. and HollyFrontier Corporation, an independent petroleum refiner and marketer. Mr. Echols brings 30 years of financial and business experience to EnLink Midstream. After 22 years with the accounting firm Arthur Andersen LLP, which included serving as managing partner of the firm s audit and business advisory practice in North Texas, Colorado and Oklahoma, Mr. Echols spent six years with Centex Corporation as executive vice president and chief financial officer. He retired from Centex Corporation in June 2006. Mr. Echols is also a member of the board of directors of Roofing Supply Group Holdings, Inc., a private company. He also served on the board of TXU Corporation where he chaired the Audit Committee and was a member of the Strategic Transactions Committee until the completion of the private equity buyout of TXU in October 2007. Mr. Echols earned a Bachelor of Science degree in accounting from Arkansas State University and is a Certified Public Accountant. He is a member of the American Institute of Certified Public Accountants and the Texas Society of CPAs. Mr. Echols has also served as a director of the General Partner since January 2008. Mr. Echols was selected to serve as a director due to his accounting and financial experience and service as the Chief Financial Officer for a public company, among other factors.

Rolf A. Gafvert was President, CEO and Director of Boardwalk GP, LLP, the General Partner of Boardwalk Pipeline Partners, LP from 2007 to 2011. Prior to that, Mr. Gafvert served as Co-President of Boardwalk GP, LLC from 2005 to 2007. Mr. Gafvert served as President of South Pipeline, which became affiliated with Boardwalk Pipeline Partners, LP in 2005, from 2000 to 2011. Mr. Gafvert was involved in Gulf South and its affiliates from 1993 to 2000, including acting as Managing Director of Koch Energy International, VP of Corporate Development for Koch Energy, Inc. and President of Gulf South. Mr. Gafvert has served as a director of the Managing Member since March 7, 2014. He holds a Master s degree in Agricultural Economics and a Bachelor of Science degree in Psychology from Iowa State University. Mr. Gafvert was selected to serve as a director due to his knowledge of the energy business and his business expertise, among other factors.

Code of Ethics

We adopted a Code of Business Conduct and Ethics (the Code of Ethics) applicable to all of our employees, officers, and directors, with regard to company-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. The Code of Ethics also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. A copy of the Code of Ethics is available to any person, free of charge, at our web site: www.enlink.com. If any substantive amendments are made to the Code of Ethics or if we grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our executive officers and directors, we will disclose the nature of such amendment or waiver on our web site.

Section 16(a) Beneficial Ownership Reporting Compliance

Prior to the consummation of the business combination on March 7, 2014, we did not have a class of equity securities registered pursuant to Section 12 of the Exchange Act and, as a result, the requirements of Section 16(a) of the Exchange Act were not applicable to our directors, executive officers and persons who own more than 10% of a class of our equity securities for our most recent fiscal year.

Independent Directors

Messrs. Crain, Echols and Gafvert and Ms. Ricciardello qualify as independent in accordance with the published listing requirements of The New York Stock Exchange (NYSE). The NYSE independence definition includes a series of objective tests, such as that the director is not an employee of the Company and has not engaged in various types of business dealings with the Company. In addition, as further required by the NYSE rules, our Board has made a subjective determination as to each independent director that no relationships exist that, in the opinion of the Board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

In addition, the members of the Audit Committee of our Board each qualify as independent under special standards established by the Securities and Exchange Commission (SEC) for members of audit committees, and the Audit Committee includes at least one member who is determined by our Board to meet the qualifications of an audit committee financial

Table of Contents

expert in accordance with SEC rules, including that the person meets the relevant definition of an independent director. Mr. Echols and Ms. Ricciardello are both independent directors who have been determined to be audit committee financial experts. Unitholders should understand that this designation is a disclosure requirement of the SEC related to their experience and understanding with respect to certain accounting and auditing matters. The designation does not impose on such directors any duties, obligations or liabilities that are greater than are generally imposed on them as members of the Audit Committee and the Board, and the designation of a director as audit committee financial experts pursuant to this SEC requirement does not affect the duties, obligations or liabilities of any other member of the Audit Committee or the Board. Additionally, the Board has determined that the simultaneous service by Mr. Echols and Ms. Ricciardello on the Audit Committees of three other publicly traded companies does not impair their ability to effectively serve on the Audit Committee of the Company.

Board Committees

Our Board established three standing committees in March 2014: the Audit Committee, the Conflicts Committee and Governance and Compensation Committee. Each member of the Audit Committee is an independent director in accordance with the NYSE standards described above. Each of the Board committees has a written charter approved by the Board. Copies of such charters and the Code of Ethics and Governance Guidelines are available to any person, free of charge, on our website at www.enlink.com.

The Audit Committee of our Board is currently comprised of Mr. Echols (chair), Mr. Crain and Ms. Ricciardello. The Audit Committee assists our Board in its general oversight of our financial reporting, internal controls and audit functions, and is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors.

The Conflicts Committee of our Board is currently comprised of Messrs. Crain (chair) and Gafvert. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not directors, officers or employees of EnLink Midstream GP, LLC. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our unitholders and not a breach by our Managing Member of any duties owed to us or our unitholders.

The Governance and Compensation Committee is comprised of Messrs. Gafvert (chair) and Hager. The Governance and Compensation Committee reviews matters involving governance, including assessing the effectiveness of current policies, monitoring industry developments, and oversees certain compensation decisions as well as the compensation plans described herein.

Item 11. ***Executive Compensation***

Prior to the consummation of the business combination on March 7, 2014, we did not have any operations nor did we design, implement or accrue any obligations with respect to compensation for the fiscal year ended December 31, 2013. Upon the consummation of the business combination, certain executive officers of EnLink Midstream, Inc. became executive officers of our Managing Member. Accordingly, this discussion relates to the compensation of Barry E. Davis, Michael J. Garberding and Joe A. Davis, each of whom was an executive officer of EnLink Midstream, Inc. and became an executive officer of the Managing Member effective as of March 7, 2014. These individuals are collectively referred to as our named executive officers. McMillan (Mac) Hummel and Steve J. Hoppe, our other executive officers, were not executive officers of us, EnLink Midstream, Inc. or Midstream Holdings prior to the business combination.

We do not directly employ any of the persons responsible for managing our business. The Managing Member manages our operations and activities, and its Board and officers make decisions on our behalf. The compensation of the executive officers and directors of the Managing Member is determined by the Board upon the recommendation of its Governance and Compensation Committee. Our named executive officers also serve as executive officers of EnLink Midstream GP, LLC (formerly known as Crosstex Energy GP, LLC), our indirect wholly-owned subsidiary and the general partner of EnLink Midstream Partners, LP (formerly known as Crosstex Energy, L.P.); therefore, the compensation of our named executive officers reflects total compensation for services to both EnLink Midstream, Inc. and the Partnership during the year ended December 31, 2013. We pay all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. We currently pay a monthly fee to EnLink Midstream GP, LLC to cover our portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

The former EnLink Midstream, Inc. compensation committee was responsible for the compensation of each of our named executive officers during the year ended December 31, 2013. Our compensation structure is substantially comparable to EnLink Midstream, Inc. s historical compensation structure, and therefore the discussion below describes EnLink Midstream, Inc. s historical compensation practices and our current compensation practices. References in this discussion to the Compensation Committee prior to the business combination refer to the Compensation Committee of EnLink Midstream, Inc. and after the business combination refer to the Governance and Compensation Committee of the Board of our Managing Member.

Table of Contents

Compensation Committee Report

The Compensation Committee has reviewed and discussed with management the following section titled Compensation Discussion and Analysis. Based upon its review and discussions, the Compensation Committee has recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Rolf A. Gafvert (Chairman)

David A. Hager

Compensation Discussion and Analysis

The Charter of the Compensation Committee includes the following:

- The Compensation Committee has general oversight responsibility for the Company s compensation plans, policies and programs. This general oversight responsibility includes reviewing and approving compensation policies and practices for all employees, overall payroll, bonus plans, overall bonus payouts, setting bonus targets, and other general compensation matters.

- The Compensation Committee is authorized to make awards under the Company s long-term incentive plans. The Compensation Committee will review and approve the total number of awards to be made from time to time. The allocation of those awards to employees that are not Executive Officers (as defined below) will be made by the Chief Executive Officer.

- Not less than annually, the Compensation Committee will review the Company s executive compensation plans and policies. The Compensation Committee will review the corporate goals and objectives relevant to the compensation of the Chief Executive Officer, any officer designated as a Section 16 Officer and each other officer that the Compensation Committee or the Board may designate (collectively referred to as the Executive Officers). The Compensation Committee will evaluate the performance of the Chief Executive Officer, and, together with the Chief Executive Officer, the performance of each other Executive Officer. The Compensation Committee will at least annually review each executive officer s base compensation, bonus, awards under the Company s long-term incentive plans, and any other compensation, and make recommendations to the Board regarding each Executive Officer s compensation. No Executive Officer may be present during any voting or deliberations by the Compensation Committee regarding his or her compensation.

- The Compensation Committee will review the policies of the Company and the General Partner regarding the compensation of directors serving on the Board and the Board of Directors of the General Partner (the GP Board) and make recommendations to the Board regarding such compensation, including meeting fees, committee fees and equity-based compensation.

- The Compensation Committee will review and oversee the Company s succession plans and leadership development programs for the Chief Executive Officer and the other Executive Officers, including reviewing from time to time reports and presentations regarding human resources, executive development, staffing, training, performance management, career development and other related matters as necessary.

- The Compensation Committee will review and approve the terms of any employment contracts, severance agreements, or other contracts with any Executive Officer, provided that the Board reserves to itself the approval of the compensation of the Executive Officers.

In order to compete effectively in our industry, it is critical that we attract, retain and motivate leaders that are best positioned to deliver financial and operational results that benefit our unitholders. It is the Compensation Committee s responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board to approve and adopt these programs.

Compensation Philosophy and Principles.

Our executive compensation is designed to attract, retain and motivate top-tier executives and align their individual interests with the interests of our unitholders. The compensation of each of our executives is comprised of base salary, bonus opportunity and restricted equity awards under long term incentive plans. The Compensation Committee s philosophy is to generally target the 50th percentile of our Peer Group (discussed below) for base salaries, target the 50th percentile of our Peer Group for bonuses (but retain discretion to reduce or increase bonus amounts to address individual performance) and to provide executives the opportunity to earn long-term compensation, in the form of equity, in the top quartile relative to our Peer Group.

Table of Contents

The Compensation Committee considers the following principles in determining the total compensation of the named executive officers:

- in order to achieve its goals, it is critical that we attract, retain and motivate highly qualified executive officers;
- base salary and bonus opportunities must be competitive in order to attract, retain and motivate highly qualified executive officers;
- equity incentive compensation should represent a significant portion of the executive s total compensation in order to retain and incentivize highly qualified executives and align their individual long term interests with the interests of unitholders;
- compensation programs must be sufficiently flexible to address special circumstances, which include payments under retention plans specifically targeted to retain highly qualified officers during challenging times; and
- the overall compensation program should drive performance and reward contributions in support of our business strategies and achievements.

Compensation Methodology.

Annually, the Compensation Committee reviews our executive compensation program in total and each element of compensation specifically. The review includes an analysis of the compensation practices of other companies in our industry, the competitive market for executive talent, the evolving demands of the business, specific challenges that we may face, and individual contributions. The Compensation Committee recommends to the Board adjustments to the overall compensation program and to its individual components as the Compensation Committee determines necessary to achieve our goals. The Compensation Committee periodically retains consultants to assist in its review and to provide input regarding its compensation program and each of its elements.

With respect to compensation objectives and decisions regarding the named executive officers for fiscal 2013, the Compensation Committee reviewed market data with respect to peer companies provided by Meridian in determining relevant compensation levels and compensation program elements for our named executive officers, including establishing their respective base salaries. In addition, Meridian has provided guidance on current industry trends and best practices to the Committee. The market data that the Committee reviewed included the base salary, bonus structure, bonus methodology and short and long-term compensation elements paid to executive officers in similar positions at our peer companies. For 2013, the Compensation Committee and Meridian collaborated to identify the following companies as Peer Companies of EnLink Midstream, Inc. for comparison purposes: Access Midstream Partners, L.P., Atlas Pipeline Partners, L.P., Buckeye Partners, L.P., LLC, DCP Midstream Partners, L.P., Eagle Rock Energy Partners, L.P., Magellan Midstream Partners, L.P., Targa Resources Partners LP, Regency Energy Partners, L.P., MarkWest Energy Partners, L.P., Western Gas Partners, L.P., Genesis Energy, L.P., NGL Energy Partners, L.P., Semgroup Corp. and Martin Midstream Partners, L.P.

In addition, the Compensation Committee reviews various relevant compensation surveys with respect to determining compensation for the named executive officers. In determining the long-term incentive component of compensation of our senior executives (including the named executive officers), the Compensation Committee considers individual performance and relative equity holder benefit, the value of similar incentive awards to senior executives at comparable companies, awards made to the company s senior executives in past years, the value of all unvested awards held by the executive, and such other factors as the Compensation Committee deems relevant.

Elements of Compensation.

For fiscal year 2013, the principal elements of EnLink Midstream, Inc. s compensation for the named executive officers were the following:

- base salary;
- annual bonus plan awards;
- long-term incentive plan awards; and
- retirement and health benefits.

The Compensation Committee reviews and makes recommendations regarding the mix of compensation, both among short- and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the named executive officers. We believe that the mix of base salary, annual bonus awards, awards under the long-term incentive plan, retirement and health benefits and perquisites and other compensation fit our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies that we require.

Base Salary. The Compensation Committee recommends base salaries for the named executive officers based on the historical salaries for services rendered to us and our affiliates, market data and responsibilities of the named executive officers. Salaries are generally determined by considering the employee s performance and prevailing levels of compensation in areas in which a particular employee works. As discussed above, except with respect to the monthly reimbursement payment that we make to EnLink Midstream GP, LLC, all of the base salaries of the named executive officers were allocated to EnLink Midstream Partners, LP as general and administration expenses. The base salaries paid to our named executive officers during fiscal year 2013 are shown in the Summary Compensation Table on page 68. The base salaries payable to our named executive officers for fiscal 2014 are as follows: Barry E. Davis $600,000; Joe A. Davis $375,000; and Michael J. Garberding $400,000.

Bonus Awards. The Compensation Committee oversees the Annual Bonus Plan and makes recommendations regarding bonuses to be awarded to each of the named executive officers. The Annual Bonus Plan is applicable to all employees. Under the plan, bonuses are awarded to our named executive officers based on a formulaic approach that utilizes a performance metric that is tied to adjusted EBITDA (see Item 6. Selected Financial Data for definition) as a guideline. The same adjusted EBITDA performance metric is used as a guideline for bonuses for all employees. The adjusted EBITDA goals are determined at the beginning of the year by the Board upon the recommendation of the Compensation Committee. Discretionary bonuses in addition to bonuses under the Annual Bonus Plan are awarded from time to time by the Compensation Committee to reward outstanding service to the Company.

The final amount of bonus for each named executive officer is determined by the Compensation Committee and recommended for approval by the Board, based upon the Compensation Committee s assessment of whether such executive met his or her performance objectives established at the beginning of the performance period. These performance objectives include the quality of leadership within the named executive officer s assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer s contribution to, and enhancement of, the desired company culture. These performance objectives are reviewed and evaluated by the Compensation Committee as a whole. Each of Barry E. Davis, Michael J. Garberding and Joe A. Davis met or exceeded their personal performance objectives for 2013. Accordingly, the Compensation Committee and the Board awarded bonuses to the named executive officers ranging from approximately 45% to 94% of base salary for 2013. Such awards were paid in March 2014 in the form of unit based awards that immediately vested and were allocated 50% in restricted incentive units of the Partnership and 50% in restricted incentive units of us.

The Compensation Committee believes that a portion of executive compensation must remain discretionary and exercises its discretion with respect to bonus awards payable to its named executive officers. The Compensation Committee may exercise its discretion to reduce the amount calculated under the formula as described above, or to supplement the amount to reward or address extraordinary individual performance, challenges and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities and external competition or opportunities.

Target adjusted EBITDA is based upon a standard of reasonable market expectations and company performance, and varies from year to year. Several factors are reviewed in determining target adjusted EBITDA, including market expectations, internal forecasts and available investment opportunities. For 2013, EnLink Midstream, Inc. s adjusted EBITDA levels for bonuses were $200.0 million for minimum equity bonuses, $220.0 million for minimum cash bonuses, $235.0 million for target cash or equity bonuses and $270.0 million for maximum cash or equity bonuses. The 2013 plan provided for named executive officers to receive bonus payouts of 6% to 13% of base salary at the minimum threshold, payouts ranging from 60% to 125% of base salary at the target level and payouts ranging from 90% to 188% of base salary at the maximum level.

Additionally, on January 14, 2014, the GP Board, upon the recommendation of its compensation committee (the GP Committee), approved and authorized the Partnership to fund a cash bonus plan in an aggregate amount of up to $10.0 million (the Transaction Bonus Plan) to reward a broad base of employees, including Barry E. Davis, Michael J. Garberding and Joe A. Davis, for the transactions with Devon. In February 2014, the GP Committee awarded $1,600,000 to Barry E. Davis under the Transaction Bonus Plan, and the GP Committee and the GP Board approved allocations to Joe A. Davis of $800,000 and to Michael J. Garberding of $800,000.

Long-Term Incentive Plans. We believe that equity awards are instrumental in attracting, retaining, and motivating employees, and that they align the interests of our officers and directors with the interests of the unitholders. In connection with the business combination, the EnLink Midstream, LLC 2014 Long-Term Incentive Plan was adopted, effective as of February 5, 2014 (the 2014 Plan). Additionally, effective as of the consummation of the business combination, we assumed the EnLink Midstream, LLC 2009 Long-Term Incentive Plan (formerly known as the Crosstex Energy, Inc. 2009 Long-Term

Table of Contents

Incentive Plan) (the 2009 Plan) in respect of the outstanding awards granted thereunder and the award agreements governing such awards, in each case subject to applicable adjustments in the manner set forth in the Merger Agreement. Our directors and officers also are eligible to participate in the EnLink Midstream GP, LLC Long-Term Incentive Plan (the GP Plan).

The Board, at the recommendation of the Compensation Committee, approves the grants of awards to our executive officers. The Compensation Committee believes that equity compensation should comprise a significant portion of a named executive officer s compensation, and considers a number of factors when determining the grants to each individual. The considerations include: the general goal of allowing the named executive officer the opportunity to earn aggregate equity compensation (comprised of our units and Partnership units) in the upper quartile of our Peer Group; the amount of unvested equity held by the individual executive; the executive s performance; and other factors as determined by the Compensation Committee.

A discussion of each plan follows:

EnLink Midstream, LLC 2014 Long-Term Incentive Plan. Employees, non-employee directors and other individuals who provide services to us or our affiliates may be eligible to receive awards under the 2014 Plan; however, the Compensation Committee has the sole discretion to determine which eligible individuals receive awards under the 2014 Plan, subject to the Board s review of awards to certain of our executive officers. The 2014 Plan is administered by the Compensation Committee and permits the grant of cash and equity-based awards, which may be awarded in the form of options, restricted unit awards, restricted incentive units, unit appreciation rights (UARs), distribution equivalent rights (DERs), unit awards, cash awards and performance awards. Subject to adjustment in accordance with the 2014 Plan, 11,000,000 common units representing limited liability company interests were initially reserved for issuance pursuant to awards under the 2014 Plan. Common units subject to an award under the 2014 that are canceled, forfeited, exchanged, settled in cash or otherwise terminated, including withheld to satisfy exercise prices or tax withholding obligations, will again become available for delivery pursuant to other awards under the 2014. Of the 11,000,000 common units that may be awarded under the 2014 Plan, 10,628,056 common units remain eligible for future grants by the Managing Member as of March 24, 2014. The long-term compensation structure is intended to align the employee s performance with long-term performance for our unitholders.

The 2014 Plan will automatically expire on the tenth anniversary of its effective date. The Board may amend or terminate the 2014 Plan at any time, subject to any requirement of unitholder approval required by applicable law, rule or regulation. The Compensation Committee may generally amend the terms of any outstanding award under the 2014 Plan at any time. However, no action may be taken by the Board or the Compensation Committee under the 2014 Plan that would materially and adversely affect the rights of a participant under a previously granted award without the participant s consent.

- *Options.* Options are rights to purchase a specified number of our common units at a specified price. Generally, the exercise price of an option cannot be less than the fair market value per common unit on the date on which the option is granted and the term of the option cannot exceed ten years from the date of grant. Options will be exercisable on such terms as the Compensation Committee determines. The Compensation Committee will also determine the time or times at which, and the circumstances under which, an option may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, form of consideration payable in settlement, method by or forms in which common units will be delivered to participants, and whether or not an option shall be in tandem with a UAR award. Under no circumstances will distributions or DERs be granted or made with respect to option awards. An option granted to an employee may consist of an option that complies with the requirements of Section 422 of the Internal Revenue Code, referred to in the 2014 Plan as an incentive unit option. In the case of an incentive unit option granted to an employee who owns (or is deemed to own) more than 10% of the total combined voting power of all classes of units, the exercise price of the option must be at least 110% of the fair market value per common unit on the date of grant and the term of the option cannot exceed five years from the date of grant.

- *Unit Appreciation Rights or UARs.* A UAR is the right to receive an amount equal to the excess of the fair market value of one common unit on the date of exercise over the grant price of the UAR. UARs will be exercisable on such terms as the Compensation Committee determines. The Compensation Committee will also determine the time or times at which and the circumstances under which a UAR may be exercised in whole or in part (including based on achievement of performance goals and/or future service requirements), the method of exercise, method of settlement, form of consideration payable in settlement, method by or forms in which common units will be delivered or deemed to be delivered to participants, whether or not a UAR shall be in tandem with an option award, and any other terms and conditions of any UAR. UARs may be either freestanding or in tandem with other awards. Under no circumstances will distributions or DERs be granted or made with respect to UAR awards.

Table of Contents

- *Restricted Units.* A restricted unit is a grant of a common unit subject to a substantial risk of forfeiture, restrictions on transferability and any other restrictions determined by the Compensation Committee. The Compensation Committee may provide, in its discretion, that the distributions made by us with respect to the restricted units shall be subject to the same forfeiture and other restrictions as the restricted unit and, if so restricted, such distributions shall be held, without interest, until the restricted unit vests or is forfeited with the unit distribution right being paid or forfeited at the same time, as the case may be. In addition, the Compensation Committee may provide that such distributions be used to acquire additional restricted units for the participant. Under no circumstances will DERs be granted or made with respect to restricted unit awards.

- *Restricted Incentive Units.* Restricted incentive units are rights to receive cash, common units or a combination of cash and common units at the end of a specified period. Restricted incentive units may be subject to restrictions, including a risk of forfeiture, as determined by the Compensation Committee. The Compensation Committee may, in its sole discretion, grant DERs with respect to restricted incentive units.

- *Distribution Equivalent Rights or DERs.* DERs entitle a participant to receive cash or additional awards equal to the amount of any cash distributions made by us with respect to a common unit during the period the right is outstanding. DERs may be granted as a stand-alone award or with respect to awards other than restricted units, options or UARs. Subject to Section 409A of the Internal Revenue Code, payment of a DER issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the Compensation Committee.

- *Unit Awards.* The 2014 Plan permits the grant of unit awards, which are common units that are not subject to vesting restrictions.

- *Cash Awards.* The 2014 Plan permits the grant of cash awards, which are awards denominated and payable in cash.

- *Performance Awards.* Performance awards represent a participant s right to receive an amount of cash, common units, or a combination of both, contingent upon the annual attainment of specified performance measures within a specified period. The Compensation Committee will determine the applicable performance period, the performance goals and such other conditions that apply to each performance award. In addition, the 2014 Plan permits, but does not require, the Compensation Committee to structure any performance award made to a covered employee as qualified performance-based compensation under Section 162(m) of the Internal Revenue Code. Section 162(m) of the Internal Revenue Code generally limits the deductibility for federal income tax purposes of annual compensation paid to certain top executives of a company to $1 million per covered employee in a taxable year (to the extent such compensation does not constitute qualified performance-based compensation under Section 162(m) of the Internal Revenue Code). Prior to the payment of any compensation based on the achievement of performance goals applicable to qualified performance awards, the Compensation Committee must certify in writing that applicable performance goals and any of the material terms thereof were, in fact, satisfied.

Upon a change of control of the Company and except as provided in the award agreement, the Compensation Committee may cause unit options and UAR grants to be vested, may cause change of control consideration to be paid in respect of some or all of such awards, or may make other adjustments (if any) that it deems appropriate with respect to such awards. With respect to other awards, upon a change of control of the Company and except as provided in the award agreement, the Compensation Committee may cause such awards to be adjusted, which adjustments may relate to the vesting or the other terms of such awards.

EnLink Midstream 2009 Long-Term Incentive Plan. The 2009 Plan provides for the award of unit options, restricted units, restricted incentive units and other awards (collectively, Awards) to our employees, consultants and outside directors. As a result of the consummation of the business combination, it is anticipated that no future Awards will be granted under the 2009 Plan. The Compensation Committee administers the 2009 Plan and has the authority to grant waivers of the applicable long-term incentive plan terms, conditions, restrictions and limitations. As of March 24, 2014, 450,221 common units are reserved for issuance under the 2009 Plan. Each outstanding unit award has a vesting period that was established in the sole discretion of the Compensation Committee and as modified by the waivers entered into by certain individuals in connection with the business combination, provided that earlier vesting may arise by reason of death, disability, retirement or otherwise.

The Compensation Committee may amend, modify, suspend or terminate the 2009 Plan, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring unitholder approval under any applicable legal requirements will be effective until such approval has been obtained.

The total value of the equity compensation granted to our executive officers generally has been awarded 50% in restricted units of the Partnership and 50% in restricted stock of EnLink Midstream, Inc. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2013, EnLink Midstream, Inc. granted 64,292, 31,196 and 50,437 restricted shares to Barry E. Davis, Joe A. Davis and Michael J. Garberding, respectively. All restricted units that we grant are charged against earnings according to FASB ASC 718.

Table of Contents

EnLink Midstream GP, LLC Long-Term Incentive Plan. EnLink Midstream GP, LLC has adopted the GP Plan for employees, consultants and independent contractors of EnLink Midstream GP, LLC and its affiliates and outside directors of the GP Board who perform services for the Partnership. The GP Plan is administered by the GP Committee and permits the grant of awards, which may be awarded in the form of restricted incentive units or unit options. An aggregate of 9,070,000 common units representing limited partner interests in the Partnership are authorized for issuance under the GP Plan. Of the 9,070,000 common units that may be awarded under the GP Plan, 3,332,750 common units remain eligible for future grants by the General Partner as of March 24, 2014. The long-term compensation structure is intended to align the employee s performance with long-term performance for the Partnership s unitholders.

The GP Board, in its discretion, may terminate or amend the GP Plan at any time with respect to any units for which a grant has not yet been made. The GP Board also has the right to alter or amend the GP Plan or any part of the GP Plan from time to time, including increasing the number of units that may be granted subject to the approval requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits of the participant without the consent of the participant.

- *Unit Options.* The GP Plan currently permits the grant of options covering common units. Under current policy all unit option grants will have an exercise price that is not less than 100% the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the GP Committee. In addition, except as provided in an award agreement, upon a change of control of the Partnership or the General Partner, the GP Committee may cause unit option grants to be vested, may cause change of control consideration to be paid in respect of some or all of such options, or may make other adjustments (if any) that it deems appropriate with respect to such options. The General Partner will be entitled to reimbursement by the Partnership for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by the Partnership. If the Partnership issues new common units upon exercise of the unit options, the total number of common units outstanding will increase, and the General Partner will pay the Partnership the proceeds it received from the optionee upon exercise of the unit option. The unit options granted pursuant to the GP Plan have been designed to furnish additional compensation to employees, consultants, independent contractors and directors and to align their economic interests with those of common unitholders.

- *Restricted Incentive Units.* Awards of restricted incentive units are rights that entitle the grantee to receive common units of the Partnership upon the vesting of such restricted incentive units. The GP Committee will determine the terms, conditions and limitations applicable to any awards of restricted incentive units. Awards of restricted incentive units will have a vesting period established in the sole discretion of the GP Committee, which may include, without limitation, accelerated vesting upon the achievement of specified performance goals. In addition, except as provided in an award agreement, upon a change of control of the Partnership or the General Partner, the GP Committee may cause such awards to be adjusted, which adjustments may relate to the vesting or the other terms of such awards. Common units to be delivered upon the vesting of restricted incentive units may be common units acquired by the General Partner in the open market, common units already owned the General Partner, common units acquired by the General Partner directly from us or any other person or any combination of the foregoing. The General Partner will be entitled to reimbursement by the Partnership for the cost incurred in acquiring common units. If the Partnership issues new common units upon vesting of the restricted incentive units, the total number of common units outstanding will increase. The GP Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted incentive units which entitles the grantee to distributions attributable to the restricted incentive units prior to vesting of such units. The Partnership intends the issuance of the common units upon vesting of the restricted incentive units under the GP Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under current policy, GP Plan participants will not pay any consideration for the common units they receive, and the Partnership will receive no remuneration for the units.

For fiscal year 2013, the General Partner granted 63,113, 30,604 and 49,462 restricted incentive units to Barry E. Davis, Joe A. Davis and Michael J. Garberding, respectively. All restricted incentive units that the Partnership grants are charged against earnings according to FASB Accounting Standards Codification 718 Compensation Stock Compensation (ASC 718).

Retirement and Health Benefits. We offer a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as our other employees. We maintain a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2013, we matched 100% of every dollar contributed for contributions of up to 6% of salary (not to exceed the maximum amount permitted by law) made by eligible participants. A portion of the retirement benefits provided to the named executive officers were allocated to us as general and administration expenses. Our executive officers are also eligible to participate in any additional retirement and health benefits available to our other employees.

Table of Contents

Perquisites. We do not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax and related expenses for membership in an industry related private lunch club (totaling less than $2,500 per year per person).

Employment and Severance Agreements

Barry E. Davis, Joe A. Davis, Michael J. Garberding and certain members of senior management entered into employment agreements with the General Partner as of February 28, 2012. These employment agreements are substantially similar with certain exceptions which are set forth in the following discussion. The term of the agreement for Barry E. Davis is three years, expiring on February 28, 2015. The initial term of the employment agreements for Joe A. Davis and Michael J. Garberding was two years, but, pursuant to amendments entered into on February 25, 2014, the terms of the foregoing agreements were extended until August 31, 2014. The term of the employment agreements for other members of senior management is one year with automatic extensions such that the remaining term of the agreements will not be less than one year. The employment agreements restrict such employees from disclosing confidential information, soliciting other employees to accept employment with a third party or terminate their employment with our general partner or its affiliates or competing with our general partner and its affiliates, in each case for a period that will continue after the termination of the employee s employment for one year for Barry E. Davis and for six months for the other executive officers and members of senior management. During the noncompetition period, the employees are generally prohibited from engaging in any business that competes with us or our affiliates in areas in which we conduct business as of the date of termination and from soliciting or inducing any of our employees to terminate their employment with us. The employment agreements provide a clawback of benefits if the confidential information or noncompetition provisions are breached by a terminated employee following a termination date. In the event of a termination, the terminated employee is required to execute a general release of us in order to receive any benefits under the employment agreements.

Under the employment agreements, employees receive their annual base salary and are eligible to participate in cash and equity incentive bonus programs based on criteria established by the Board. If an employee s employment is terminated without cause (as defined in the employment agreement), or is terminated by the employee for good reason (as defined in the employment agreement), or is terminated due to the employee s death, disability or adjudication of legal incompetence, the employment agreement provides that the employee will be entitled to receive (i) his or her base salary up to the date of termination, (ii) any unpaid annual bonus with respect to the prior year that has been earned as of or prior to the date of termination (iii) a pro-rata portion of the higher of (x) the target amount of his or her annual bonus and (y) the projected annual bonus, in each case calculated based upon the number of days in the performance period prior up to the date of termination, (iv) an amount equal to the cost to the employee for the premium for health insurance continuation under COBRA for an 18-month period, (v) such other fringe benefits (excluding any bonus, severance pay benefit, participation in the company s 401(k) employee benefit plan, or medical insurance benefit) normally provided to employees of the company and already earned or accrued as of the date of termination (collectively, the Termination Fee) and (vi) a lump sum severance amount equal to one year of the employee s then current base salary, plus one times the target annual bonus for the year of termination (the amount listed in (vi) the Severance Benefit); provided, however, that the Severance Benefit for the Chief Executive Officer is multiplied by two.

Potential Payments Upon Termination and a Change of Control.

As described above, the employment agreements for our named executive officers and certain members of senior management provide for payment to be made to them under certain circumstances upon the termination of their employment. In connection with determining the type, amount and timing of the payment to be made upon the termination of employment under the employment agreements, the Compensation Committee reviewed available market information and identified those payments and provision that the Compensation Committee deemed to be appropriate for inclusion in the employment agreements. In the event of an executive officer s termination without cause, or a termination by the employee for good reason, within 120 days prior to or one year following a change of control (as defined in the employment agreements), Barry E. Davis would be entitled to receive the Termination Fee plus a lump sum severance amount equal to three times the Severance Benefit, and Joe

A. Davis and Michael J. Garberding each would be entitled to receive the Termination Fee plus a lump sum severance amount equal to two times the Severance Benefit. Other members of senior management do not receive an increase in the Severance Benefit if they are terminated in connection with a change of control.

If the payments and benefits provided to an executive officer (i) constitute a parachute payment as defined in Section 280G of the Internal Revenue Code and exceed three times executive officer s base amount as defined under Internal Revenue Code Section 280G(b)(3), and (ii) would be subject to the excise tax imposed by Internal Revenue Code Section 4999, then the executive officer s payments and benefits shall be either (A) paid in full, or (B) reduced and payable only as to the maximum amount which would result in no portion of such payments and benefits being subject to excise tax under Internal Revenue Code Section 4999, whichever results in the receipt by the executive officer on an after-tax basis of the greatest amount (taking into account the applicable federal, state and local income taxes, the excise tax imposed by Internal Revenue Code Section 4999 and all other taxes, including any interest and penalties, payable by the executive officer).

Table of Contents

With respect to the long-term incentive plans, the amounts, if any, to be received by our named executive officers in the event of a change of control (as defined in the long-term incentive plans) will be automatically determined based on the terms of the long-term incentive plans or, if applicable, the equity incentive awards held by a named executive officer at the time of a change of control. These terms are determined based on past practice and the applicable compensation committee s understanding of similar plans utilized by public companies generally at the time we adopted such plans. The determination of the reasonable consequences of a change of control is periodically reviewed by the applicable compensation committee.

The consummation of the business combination constituted a change in control of EnLink Midstream, Inc., the General Partner and the Partnership under the applicable long-term incentive plans (the Devon Change in Control). However, Barry E. Davis, Michael J. Garberding and Joe A. Davis each agreed to waive certain rights with respect to the acceleration and vesting of awards in connection with the Devon Change in Control. As a result of such waiver, the applicable awards did not become payable or vest solely as a result of the Devon Change in Control. Such awards granted in or with respect to shares of EnLink Midstream, Inc. s common stock were converted to awards in respect of our common units (as described above) and awards granted in or with respect to the Partnership s common units were unchanged following the Devon Change in Control. As consideration for such waivers, EnLink Midstream, Inc. s board of directors and the GP Board, upon the recommendation of their respective compensation committees, approved and authorized EnLink Midstream, Inc. and the Partnership to fund a cash bonus pool in an aggregate amount of approximately $600,000 to provide cash awards to these individuals. In February 2014, the compensation committees awarded approximately $258,968 to Barry E. Davis pursuant to this cash bonus pool, and the compensation committees, the EnLink Midstream, Inc. board of directors and the GP Board approved allocations of approximately $114,268 and approximately $196,944 to Joe A. Davis and Michael J. Garberding, respectively, pursuant to this cash bonus pool.

Role of Executive Officers in Executive Compensation.

The Board, upon recommendation of the Compensation Committee, determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Compensation Committee. Barry E. Davis, the Chief Executive Officer, reviews his recommendations regarding the compensation of his leadership team with the Compensation Committee, including specific recommendations for each element of compensation for the named executive officers. Barry E. Davis does not make any recommendations regarding his personal compensation.

Tax and Accounting Considerations.

Our equity compensation grant policies have been impacted by the implementation of FASB ASC 718, which we adopted effective January 1, 2006. Under this accounting pronouncement, we are required to value unvested unit options granted prior to our adoption of FASB ASC 718 under the fair value method and expense those amounts in the income statement over the unit option s remaining vesting period. As a result, we currently intend to discontinue grants of unit option awards and instead grant restricted unit and restricted stock awards to the named executive officers and other employees. We have structured the compensation program to comply with Internal Revenue Code Section 409A. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. In 2013, none of the named executive officers or other employees had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Internal Revenue Code Section 162(m).

Table of Contents

Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers. As discussed above, the amounts below reflect the historical compensation of each of Barry E. Davis, Michael J. Garberding and Joe A. Davis for their service as executive officers of EnLink Midstream, Inc.

[redacted]							
Barry E. Davis	2013	525,000	492,188	1,609,522		266,774(3)	2,893,484
President and Chief Executive	2012	500,000	406,250	1,333,787		257,496	2,497,533
Officer	2011	460,000	545,882	1,418,773		195,958	2,620,613
[redacted]							
Michael J. Garberding	2013	350,000	224,100	1,465,519		164,596(5)	2,204,215
Executive Vice President and	2012	290,000	141,375	640,212		138,874	1,210,461
Chief Financial Officer	2011	256,538	197,894	848,713		88,124	1,391,269

---

(1) Bonuses include all payments made under the Annual Bonus Plan. For 2013 and 2012, the named executive officers received bonuses in the form of stock awards that immediately vest. The amounts shown for 2013 and 2012 represent the grant date fair value of awards computed in accordance with FASB ASC 718. Such awards were allocated 50% in restricted incentive units of EnLink Midstream Partners, LP and 50% in restricted stock of EnLink Midstream, Inc. Because the 2013 awards were paid following the consummation of the business combination, they were paid in restricted incentive units of us. See Bonus Awards above.

(2) The amounts shown represent the grant date fair value of awards computed in accordance with FASB ASC 718. Assumptions used in the calculation of these amounts include the grant date fair value of each restricted award and the number of restricted awards issued on January 15, 2013 and August 7, 2013, which are detailed in the tables under EnLink Midstream, Inc. Grants of Plan-Based Awards and EnLink Midstream GP, LLC Grants of Plan-Based Awards. The grant date fair values for the January 15, 2013 restricted awards for EnLink Midstream, Inc. and EnLink Midstream Partners, LP are $15.36 and $15.64, respectively. The grant date fair values for the August 7, 2013 restricted awards for EnLink Midstream, Inc. and EnLink Midstream Partners, LP are $20.04 and $21.19, respectively. The aggregate grant date fair value for the restricted unit awards is determined by multiplying a number of units by the respective grant date fair value.

(3) Amount of all other compensation for Mr. Barry Davis includes professional organization and social club dues, a matching 401(k) contribution of $18,368, distributions on restricted incentive units and performance units of the Partnership in the amount $165,216 in 2013, and dividends on restricted stock and performance shares of EnLink Midstream, Inc. in the amount of $80,673 in 2013.

(4) Amount of all other compensation for Mr. Joe Davis includes professional organization and social club dues, a matching 401(k) contribution of $17,900, distributions on restricted incentive units and performance units of the Partnership in the amount of $76,388 in 2013, and dividends on restricted stock and performance shares of EnLink Midstream, Inc. in the amount of $37,278 in 2013.

(5) Amount of all other compensation for Mr. Michael Garberding includes professional organization and social club dues, a matching 401(k) contribution of $17,500, distributions on restricted incentive units of the Partnership in the amount of $97,843 in 2013, and dividends on restricted stock of EnLink Midstream, Inc. in the amount of $46,737 in 2013.

Grants of Plan-Based Awards for Fiscal Year 2013 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2013 by EnLink Midstream, Inc. and EnLink Midstream GP, LLC, including awards made under their applicable long-term incentive plans. As discussed above, awards denominated in shares under the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan have been assumed by us and converted into awards denominated in our common units.

Table of Contents

ENLINK MIDSTREAM, INC. GRANTS OF PLAN-BASED AWARDS

[redacted]

Barry E. Davis	1/15/2013	52,301(1)	$	803,343
	3/4/2013	11,991(2)	$	203,128
[redacted]				
Michael J. Garberding	1/15/2013	31,381(1)	$	482,012
	3/4/2013	6,789(2)	$	115,006
	8/7/2013	12,267(3)	$	245,831

(1) These grants include right to receive dividends on restricted shares if made on unrestricted common shares during the restricted period unless otherwise forfeited and vest 100% on January 1, 2016.

(2) These grants vested on March 8, 2013.

(3) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted stock units if made on unrestricted common shares during the restriction period unless otherwise forfeited and vest 100% on July 31, 2016.

ENLINK MIDSTREAM GP, LLC GRANTS OF PLAN-BASED AWARDS

[redacted]

Barry E. Davis	1/15/2013	51,546(1)	$	806,179
	3/4/2013	11,567(2)	$	203,117
[redacted]				
Michael J. Garberding	1/15/2013	30,928(1)	$	483,714
	3/4/2013	6,549(2)	$	115,000
	8/7/2013	11,985(3)	$	253,962

(1) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on January 1, 2016.

(2) These grants vested on March 8, 2013.

(3) These grants include Distribution Equivalent Rights (DERs) that provide for distribution on restricted incentive units if made on unrestricted common units during the restriction period unless otherwise forfeited and vest 100% on July 31, 2016.

Table of Contents

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2013

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2013 by EnLink Midstream, Inc. and EnLink Midstream GP, LLC, including awards made under their applicable long-term incentive plans. As discussed above, awards denominated in shares under the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan have been assumed by us and converted into awards denominated in our common units.

ENLINK MIDSTREAM, INC. OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

[redacted]

Barry E. Davis	51,919(1)	1,877,391
	23,148(3)	837,032
	50,080(4)	1,810,893
	52,301(5)	1,891,204
[redacted]		
Michael J. Garberding	13,826(1)	499,948
	27,778(3)	1,004,452
	24,038(4)	869,214
	31,381(5)	1,134,737
	12,267(6)	443,575

(1) Restricted shares vested on January 1, 2014.

(2) The closing price for the common shares was $36.16 as of December 31, 2013.

(3) Restricted shares vest on August 15, 2014.

(4) Restricted shares vest on January 1, 2015.

(5) Restricted shares vest on January 1, 2016.

(6) Restricted shares vest on July 31, 2016.

Table of Contents

ENLINK MIDSTREAM GP, LLC OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

[redacted]

Barry E. Davis	31,944(1)	881,654
	15,272(3)	421,507
	38,250(4)	1,055,700
	51,546(5)	1,422,670
[redacted]		
Michael J. Garberding	8,507(1)	234,793
	18,326(3)	505,798
	18,360(4)	506,736
	30,928(5)	853,613
	11,985(6)	330,786

(1) Restricted incentive units vested on January 1, 2014.

(2) The closing price for the common units was $27.60 as of December 31, 2013.

(3) Restricted incentive units vest on August 15, 2014.

(4) Restricted incentive units vest on January 1, 2015.

(5) Restricted incentive units vest on January 1, 2016.

(6) Restricted incentive units vest on July 31, 2016.

Units and Shares Vested Table for Fiscal Year 2013

The following table provides information related to the vesting of restricted incentive units and restricted shares during fiscal year ended 2013. As discussed above, awards denominated in shares under the Crosstex Energy, Inc. 2009 Long-Term Incentive Plan have been assumed by us and converted into awards denominated in our common units.

UNITS AND SHARES VESTED

	EnLink Midstream, Inc. Share Awards			EnLink Midstream Partners, LP Unit Awards		
Name	**Number of Shares Acquired on Vesting**		**Value Realized on Vesting**	**Number of Units Acquired on Vesting**		**Value Realized on Vesting**
Barry E. Davis	46,714	$	711,248(1)	46,290	$	711,684(2)
Joe A. Davis	37,346	$				