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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2014

or

☐ **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 1-36175

MIDCOAST ENERGY PARTNERS, L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**61-1714064**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

1100 Louisiana Street,
Suite 3300,
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code (713) 821-2000

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

Title of each class	Name of each exchange on which registered
Class A common units	New York Stock Exchange

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

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

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

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 ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405) is not contained herein, and will not be contained, to the best of the 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 ☐

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

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

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

The aggregate market value of the registrant's Class A common units held by non-affiliates computed by reference to the price at which the common equity was last sold on June 30, 2014, was $466,196,720.

As of February 13, 2015, the registrant has 22,610,056 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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Unless the context otherwise requires, references in this report to "the Predecessor," "we," "our," "us," or like terms, when used in a historical context (before November 13, 2013), refer to Midcoast Operating, L.P. References in this report to "Midcoast Energy Partners," "the Partnership," "we," "our," "us," or like terms used in the present tense or prospectively (on and after November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries. We refer to our general partner, Midcoast Holdings, L.L.C., as our "General Partner" or "Midcoast Holdings", and refer to Enbridge Energy Partners, L.P. and its subsidiaries, other than us, as "Enbridge Energy Partners," or "EEP." References to "Enbridge" refer collectively to Enbridge Inc. and its subsidiaries other than us, our subsidiaries, our General Partner and EEP, its subsidiaries and its general partner. References to "Midcoast Operating" refer to Midcoast Operating, L.P. and its subsidiaries. After the closing of our initial public offering on November 13, 2013, we owned a 39% controlling interest in Midcoast Operating, and EEP owned a 61% noncontrolling interest in Midcoast Operating; however, on July 1, 2014, we acquired an additional 12.6% interest in Midcoast Operating from EEP. As of December 31, 2014 the ownership percentages for us and EEP were 51.6% and 48.4%, respectively. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP's noncontrolling interest in Midcoast Operating.

This Annual Report on Form 10-K includes forward-looking statements, which are statements that frequently use words such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "should," "strategy," "target," "will" and similar words. Although we believe that such forward-looking statements are reasonable based on currently available information, such statements involve risks, uncertainties and assumptions and are not guarantees of performance. Future actions, conditions or events and future results of operations may differ materially from *those expressed in these forward-looking statements. Any forward-looking statement made by us in this Annual Report on Form 10-K speaks only as of the date on which it is made, and we undertake no obligation to publicly update any forward-looking statement. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include: (1) changes in the demand for or the supply of, forecast data for, and price trends related to natural gas, natural gas liquids, or NGLs, and crude oil, and the response by natural gas and crude oil producers to changes in any of these factors (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline and gathering systems, as well as other processing and treating plants; (4) shut-downs or cutbacks at our facilities or refineries, petrochemical plants, utilities or other businesses for which we transport products or to whom we sell products; (5) hazards and operating risks that may not be covered fully by insurance; (6) changes in or challenges to our rates; and (7) changes in laws or regulations to which we are subject, including compliance with environmental and operational safety regulations that may increase costs of system integrity testing and maintenance.*

For additional factors that may affect results, see "Item 1A. Risk Factors" included elsewhere in this Annual Report on Form 10-K, our subsequently filed Quarterly Reports on Form 10-Q, and Current Reports on Form 8-K which are available to the public over the Internet at the U.S. Securities and Exchange Commission's, or the SEC's, website (www.sec.gov) and at our website (www.midcoastpartners.com).

Glossary

The following abbreviations, acronyms and terms used in this Form 10-K are defined below:

Anadarko system	Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle which serve the Anadarko basin, inclusive of the Elk City system
AOCI	Accumulated other comprehensive income
Bbl	Barrel of liquids (approximately 42 United States gallons)
Bpd	Barrels per day
CAA	Clean Air Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CWA	Clean Water Act
DOT	United States Department of Transportation
East Texas system	Natural gas gathering, treating and processing assets in East Texas that serve the Bossier trend and Haynesville shale areas, also includes a system formerly known as the Northeast Texas system
EBITDA	Earnings before Interest, Taxes, Depreciation and Amortization
EEP	Enbridge Energy Partners, L.P. and its subsidiaries other than Midcoast Energy Partners, L.P. and its subsidiaries
Elk City system	Elk City natural gas gathering and processing system located in western Oklahoma in the Anadarko basin
Enbridge	Enbridge Inc., of Calgary, Alberta, Canada, the ultimate parent of the General Partner
Enbridge Management	Enbridge Energy Management, L.L.C.
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
General Partner	Midcoast Holdings, L.L.C., the general partner of the Partnership
HB 500	House Bill 500
HCDP Plants	Hydrocarbon dewpoint control facilities
ICA	Interstate Commerce Act
ISDA®	International Swaps and Derivatives Association, Inc.
LIBOR	London Interbank Offered Rate—British Bankers' Association's average settlement rate for deposits in United States dollars
MEP	Midcoast Energy Partners, L.P. and its consolidated subsidiaries
MLP	Master Limited Partnership
MMBbls	Million barrels of liquids
MMBtu/d	Million British Thermal units per day
MMcf/d	Million cubic feet per day
NGA	Natural Gas Act of 1938
NGL or NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968
North Texas system	Natural gas gathering and processing assets located in the Fort Worth basin serving the Barnett Shale area
NPNS	Normal purchases and normal sales
NSPS	New Source Performance Standards
NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
Offering	MEP initial public offering
OLP	Enbridge Energy, Limited Partnership

OPA	Oil Pollution Act
Partnership Agreement	First Amended and Restated Agreement of Limited Partnership of Midcoast Energy Partners, L.P., also referred to as our partnership agreement
Partnership	Midcoast Energy Partners, L.P. and its consolidated subsidiaries
PHMSA	Pipeline and Hazardous Materials Safety Administration
POL	Percentage of liquids
PSA	Pipeline Safety Act of 1992
PSIA	Pipeline Safety Improvement Act of 2002
SEC	United States Securities and Exchange Commission
TRRC	Texas Railroad Commission
TSX	Toronto Stock Exchange
U.S. GAAP	United States Generally Accepted Accounting Principles

PART I

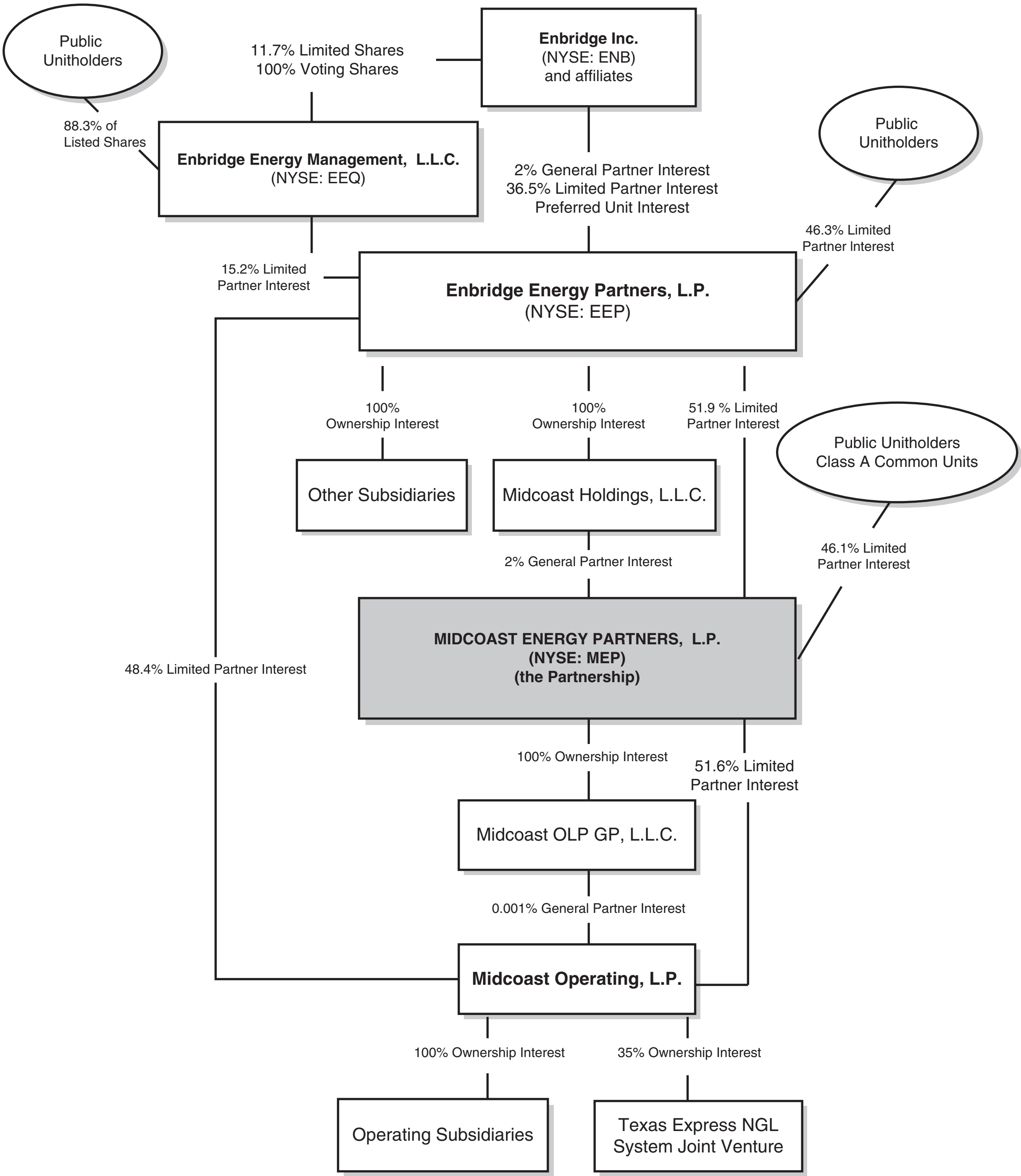
Item 1. Business

OVERVIEW

We are a publicly traded growth-oriented Delaware limited partnership formed in 2013 by EEP to serve as EEP's primary vehicle for owning and growing its natural gas and NGL midstream business in the United States. As a pure-play U.S. natural gas and NGL midstream business, we are able to pursue a focused and flexible strategy, have direct access to the equity and debt capital markets, and have the opportunity to grow through organic growth opportunities and acquisitions, including potential additional drop-down transactions from EEP. Our Class A common units are traded on the New York Stock Exchange, or NYSE, under the symbol "MEP."

After the closing of our initial public offering, or the Offering, we owned a 39% controlling interest in Midcoast Operating, and EEP owned a 61% noncontrolling interest in Midcoast Operating. On July 1, 2014, EEP sold an additional 12.6% limited partner interest in Midcoast Operating to us, which reduced EEP's total ownership interest in Midcoast Operating from 61% to 48.4% and increased our ownership from 39% to 51.6%. Unless otherwise specifically noted, financial results and operating data are shown on a 100% basis and are not adjusted to reflect EEP's 61% noncontrolling interest in Midcoast operating through June 30, 2014, and EEP's 48.4% noncontrolling interest in Midcoast Operating after June 30, 2014.

The following chart shows our organization and ownership structure as of December 31, 2014. The ownership percentages referred to below illustrate the relationships among us, Midcoast Operating, our General Partner, EEP, Enbridge and its affiliates:



We own a 51.6% controlling interest in Midcoast Operating, a Texas limited partnership that owns a network of natural gas and NGL gathering and transportation systems, natural gas processing and treating facilities and NGL fractionation facilities primarily located in Texas and Oklahoma. We also own 100% of Midcoast Operating's general partner. Midcoast Operating also owns and operates natural gas, condensate and NGL logistics and marketing assets that primarily support its gathering, processing and transportation business. Through our ownership of Midcoast Operating's general partner, we control, manage and operate these systems. EEP has a 48.4% noncontrolling interest in Midcoast Operating.

Our business primarily consists of gathering unprocessed and untreated natural gas from wellhead locations and other receipt points on our systems, processing the natural gas to remove NGLs and impurities at our processing and treating facilities and transporting the processed natural gas and NGLs to intrastate and interstate pipelines for transportation to various customers and market outlets. In addition we market natural gas and NGLs to wholesale customers.

We seek to provide our customers with best-in-class field-level service and responsiveness using our significant platform of natural gas and NGL infrastructure. We are able to provide our customers with integrated wellhead-to-market service from our systems to major energy market hubs in the Gulf Coast and Mid-Continent regions of the United States. From these market hubs, natural gas and NGLs are either consumed in local markets or transported to consumers in the midwest, northeast and southeast United States.

Midcoast Operating's primary operating assets include:

- approximately 11,100 miles of natural gas gathering and transportation lines and approximately 233 miles of NGL gathering and transportation lines;
- a 35% interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties that together own a 593 mile, 20-inch NGL intrastate transportation pipeline extending from the Texas Panhandle to Mont Belvieu, Texas and a related NGL gathering system that consists of approximately 116 miles of gathering lines;
- 18 active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, with a combined capacity of approximately 1.6 billion cubic feet per day, or Bcf/d, including 350 million cubic feet per day, or MMcf/d, provided by our HCDP plants;
- eight active natural gas treating plants, including three that are leased from third parties, with a total combined capacity of approximately 0.9 Bcf/d;
- approximately 545 compressors with approximately 792,000 aggregate horsepower, the substantial majority of which are owned by Midcoast Operating and the remainder of which are leased from third parties;
- a liquids railcar loading facility near Pampa, Texas, which we refer to as our TexPan liquids railcar facility;
- an approximately 40-mile crude oil pipeline and associated crude oil storage facility near Mayersville, Mississippi, including a crude oil barge loading facility located on the Mississippi River; and
- approximately 225 transport trucks, 370 trailers and 190 railcars for transporting NGLs.

BUSINESS STRATEGY

Our principal financial objective is to increase the amount of cash distributions we make to our unitholders over time while maintaining our focus on safety and stability in our business. Our plan for executing this objective includes the following key business strategies:

1. Deliver our services safely and reliably

We are committed to maintaining and continually improving the safety, reliability and efficiency of our operations, which we believe is key to attracting new customers and maintaining relationships with our current customers, regulators and the communities in which we operate. We strive for operational excellence by utilizing robust programs to integrate environmental integrity, health and occupational safety and risk management principles throughout our business. We employ comprehensive integrity management, inspection, monitoring and audit initiatives in support of this strategy.

2. ***Enhance the profitability of our existing assets***

To address the increasing producer focus on the liquids portion of the midstream natural gas value chain, we expect to continue to increase our natural gas processing capacity, NGL takeaway capacity options, and our third-party fractionation alternatives, which we believe will, over the long-term, increase the attractiveness and profitability of our natural gas and NGL systems, attract new customers and increase our business with existing customers. We seek to capitalize on opportunities to attract new customers, increase volumes of natural gas and NGLs that we gather, transport, process or treat and otherwise enhance utilization and operating efficiencies, including increasing customer access to preferred natural gas and NGL markets. We are committed to increase our percentage of fee-based contracts to reduce commodity exposure and further strengthen our profitability. We believe our approach will provide our customers with greater value for their commodities and increase the utilization of our natural gas and NGL systems.

3. ***Maintain a conservative and flexible capital structure and target investment grade credit metrics in order to lower our overall cost of capital.***

We intend to maintain a balanced capital structure that should afford us access to the capital markets at a competitive cost of capital. Although we do not currently have a credit rating, we plan to target debt-to-EBITDA, EBITDA-to-interest and other key credit metrics that are consistent with investment grade rated businesses in our industry. We intend to finance long-term growth projects and acquisitions with a balanced combination of debt and equity that we believe will, together with our balanced capital structure, promote the long-term stability of our business.

4. ***Pursue economically attractive organic growth opportunities***

We seek out attractive organic expansion and asset enhancement opportunities that leverage our existing asset footprint, strategic relationships with our customers and our management team's expertise in constructing, developing and optimizing midstream infrastructure assets. The organic development projects we pursue are designed to extend our geographic reach, diversify our customer base, expand our gathering systems and our processing and treating capacity, enhance end-market access and/or maximize throughput volumes. For more information relating to growth opportunities refer to *Business Segments.*

5. ***Pursue accretive acquisitions from EEP and third parties***

We intend to pursue acquisitions of additional interests in Midcoast Operating from EEP, as well as accretive acquisitions from third parties that complement or diversify our existing operations. EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time, although EEP is not legally obligated to do so. We do not know when or if any such additional interests will be offered to us to purchase.

BUSINESS SEGMENTS

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing.

These segments have unique business activities that require different operating strategies. For information relating to revenues from third-party customers, operating income and total assets for each segment, refer to Note 16. *Segment Information* of our consolidated financial statements included in Item 8. *Financial Statements and Supplementary Data* of this report.

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. We gather natural gas from the wellhead and central receipt points on our systems, deliver it to our facilities for processing and treating and deliver the residue gas to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies. We deliver the NGLs produced at our processing and fractionation facilities to intrastate and interstate pipelines for transportation to the NGL market hubs in Mont Belvieu, Texas and Conway, Kansas. In addition, we deliver NGLs from certain of our facilities to the Texas Express NGL system for transportation on the Texas Express NGL mainline to Mont Belvieu, Texas.

Our gathering, processing and transportation business consists of the following four systems:

- *Anadarko system:* Approximately 3,100 miles of natural gas gathering and transportation pipelines, approximately 60 miles of NGL pipelines, seven active natural gas processing plants, five standby natural gas processing plants and one standby treating plant located in the Anadarko basin.
- *East Texas system:* Approximately 4,100 miles of natural gas gathering and transportation pipelines, approximately 144 miles of NGL pipelines, four active natural gas processing plants, including two HCDP plants, seven active natural gas treating plants, two standby natural gas treating plants and one fractionation facility located in the East Texas basin.
- *North Texas system:* Approximately 3,900 miles of natural gas gathering and transportation pipelines, approximately 29 miles of NGL pipelines, and seven active natural gas processing plants located in the Fort Worth basin.
- *Texas Express NGL system:* A 35% interest in an approximately 593-mile NGL intrastate transportation mainline and a related NGL gathering system that consists of approximately 116 miles of gathering lines.

In addition we have, an approximately 40-mile non-core propylene pipeline extending from Exxon's refinery in Chalmette, Louisiana to an interconnecting Chevron pipeline near Lafitte, Louisiana.

Customers. Our gathering, processing and transportation business serves customers predominantly in the Gulf Coast region of the United States and includes both upstream customers and purchasers of natural gas and NGLs. Upstream customers served by our systems primarily consist of small, medium and large independent operators and large integrated energy companies, while our demand market customers primarily consist of large users of natural gas, such as power plants, industrial facilities, local distribution companies and other large consumers. Due to the cost of making physical connections from the wellhead to gathering systems, the majority of our customers tend to renew their gathering and processing contracts with us rather than seeking alternative gathering and processing services.

Supply and Demand. Demand for our gathering, processing and transportation services primarily depends upon the supply of natural gas reserves and associated natural gas from crude oil development, and the drilling rate for new wells. The level of impurities in the natural gas gathered also affects treating services. Demand for these services depends upon overall economic conditions, drilling activity and the prices of natural gas, NGLs, and condensates. Commodity prices for natural gas, NGLs, and condensates began declining in the fourth quarter of 2014 and into 2015. As a result, there has been recent reduction in drilling activity by producers. Our existing systems are located in basins that have the opportunity to grow in an improved pricing environment. All of our gathering, processing and transportation systems exist in regions that have shale or tight sands formations where horizontal fracturing technology can be utilized to increase production from the natural gas wells.

Anadarko System

Our Anadarko system includes production from the Granite Wash tight sand formation. Productive horizons in the Granite Wash play include the Hogshooter, Checkerboard, Cleveland, Skinner, Red Fork, Atoka and Morrow formations. Recent decreases in NGL and condensate prices have resulted in decreased activity in the region. The Anadarko basin wells generally have long lives with predictable flow rates. Producers generally pursue wells with higher condensate and oil production relative to historical activity that was focused on natural gas and NGL prospects.

We expect development of the Granite Wash play in the Texas Panhandle and western Oklahoma to continue due to the prolific nature of the wells, and to increase when market prices for NGLs and crude oil increase. In order to accommodate the expected growth of the Granite Wash play, we began commissioning the operations of a cryogenic processing plant in the third quarter of 2013, which we refer to as our Ajax processing plant. The Ajax processing plant, condensate stabilizer, field and plant compression, gathering infrastructure and NGL pipelines assist in meeting the anticipated volume growth within our Anadarko system. The total cost of constructing the Ajax processing plant and related facilities was approximately $230.0 million. The Ajax processing plant increased the total processing capacity of our Anadarko system by approximately 150 million MMcf/d to approximately 1,150 MMcf/d and also increased the system's condensate stabilization capacity by approximately 2,000 barrels per day, or Bpd. The Ajax processing plant is capable of producing approximately 15,000 Bpd of NGLs now that the Texas Express NGL pipeline, which we refer to as the mainline, is in operation.

With recent commodity prices declining we have idled approximately five less efficient processing plants and consolidated volumes to our more efficient plants, such as Ajax. These plants are available for restart when production increases.

Our Anadarko system has numerous market outlets for the natural gas that we gather and process and NGLs and condensate that we recover on our system. We have connections to major intrastate and interstate transportation pipelines that connect our facilities to major market hubs in the Mid-Continent and Gulf Coast regions of the United States. All of our owned residue gas and condensate is sold to our logistics and marketing business. A portion of our owned NGLs is sold directly to a third-party, while the remainder is sold to our logistics and marketing business. The NGLs produced at our Anadarko system processing plants are transported by pipeline to third-party fractionation facilities and NGL market hubs in Conway, Kansas and Mont Belvieu, Texas.

East Texas System

Our East Texas system gathers production from the: Cotton Valley Lime and lean Bossier Shale plays, which are located on the western side of our East Texas system; the Haynesville/Bossier Shale plays, which run from western Louisiana into East Texas and are among the largest natural gas resources in the United States; the Cotton Valley Sand formation, which also runs from western Louisiana into East Texas and has a high content of NGLs and condensate on the eastern side of our East Texas system; and the Eaglebine play, which spans five counties in East Texas and is comprised of multiple drilling zones crossing through the Woodbine and Eagleford formations. The East Texas basin also includes multiple other natural gas and oil formations that are frequently explored, including, among others the Woodbine, Travis Peak, James Lime, Rodessa, and Pettite. The East Texas wells generally have long lives with predictable flow rates. While dry gas drilling declined with the historical decreases in gas prices, more recently, drilling activity has increased in the basin by customers pursuing rich gas and crude oil formations using horizontal drilling and multistage fracturing. In 2014, our processing plants in East Texas were at full capacity.

In the third quarter of 2013, we initiated construction activities at our Beckville processing plant and the related facilities on our East Texas system. This plant along with our significant processing infrastructure in the region is expected to serve existing and prospective customers pursuing production from formations and plays in the East Texas Basin including the Cotton Valley, James Lime, Eaglebine and other liquid rich opportunities in the area. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. We estimate the cost of constructing the plant to be approximately $145.0 million and expect it to commence commercial service early in second quarter of 2015.

Our East Texas system has numerous market outlets for the natural gas that we gather and process and NGLs and condensate that we recover on our system. We have connections to major intrastate and interstate transportation pipelines that connect our facilities to major market hubs in the United States Gulf Coast, as well as to several wholesale customers. The majority of our owned residue gas is sold to our logistics and marketing business, while the remainder of our owned residue gas is sold directly to third-party wholesale customers or utilities. All of our owned condensate is sold to our logistics and marketing business. A portion of the NGLs produced at one of our East Texas system processing plants is fractionated by us and sold directly to a third-party chemical company. The remainder of the NGLs recovered at our plants are sold to our logistics and marketing business and transported by pipeline to Mont Belvieu, Texas for fractionation.

North Texas System

A substantial portion of natural gas on our North Texas system is produced in the Barnett Shale play within the Fort Worth basin. The North Texas wells are located in the Fort Worth basin and generally have long lives with predictable flow rates. Producers are pursuing wells with higher condensate and oil production relative to historical activity due to the relatively lower valued gas prospects. As producers have shifted from dry natural gas drilling to rich gas from crude oil production, we have seen our natural gas volumes decline. However, our NGL and condensate production increased in 2014.

Our North Texas system has numerous market outlets for the natural gas that we gather and process and NGLs that we recover on our system. We have connections to major intrastate transportation pipelines that connect our facilities to market centers in the Dallas-Fort Worth area and ultimately to major market hubs in the United States Gulf Coast. The majority of our owned residue gas and all of our owned condensate and NGLs produced at our North Texas system processing plants is sold to our logistics and marketing business.

Texas Express NGL System

The Texas Express NGL system commenced startup operations during the fourth quarter of 2013. Volumes from the Rockies, Permian basin and Mid-Continent regions are delivered to the Texas Express NGL system utilizing Enterprise Products Partners' existing Mid-America Pipeline between the Conway hub and Enterprise Products Partners' Hobbs NGL fractionation facility in West Texas. In addition, volumes from and to the Denver-Julesburg basin in Weld County, Colorado can access the system through the Front Range Pipeline, which is owned by Enterprise Products Partners, DCP Midstream and Anadarko Petroleum Corporation.

Competition. Competition for our gathering, processing and transportation business is significant in all of the markets we serve. Competitors include interstate and intrastate pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs. Our gathering business' principal competitors are other midstream companies and, to a lesser extent, producer owned gathering systems. Some of these competitors are substantially larger than we are. Competition for the services we provide varies based upon the location of gathering, treating and processing facilities. Most upstream customers have alternate gathering, treating and processing facilities available to them. In addition, they have alternatives such as building their own gathering facilities or, in some cases, selling their natural gas supplies without treating and processing. In addition to location, competition also varies based upon pricing arrangements and reputation. On sour natural gas systems, such as parts of our East Texas system, competition is more limited in certain locations due to the infrastructure required to treat sour natural gas. Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipeline companies. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers we serve have multiple pipelines connected or adjacent to their facilities. Accordingly, many of these customers have the ability to purchase natural gas directly from a number of pipelines or third parties that may hold capacity on the various pipelines. In addition, several new interstate natural gas pipelines have been and are being constructed in areas currently served by our natural gas transportation pipelines. Some of these new pipelines may compete for customers with our existing pipelines.

Logistics and Marketing

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business, thereby enhancing our competitive position. In addition, our logistics and marketing services provide our customers with the opportunity to receive enhanced economics by providing access to premium markets through the transportation capacity and other assets we control. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from pipeline systems and processing plants and sells and delivers them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants.

The physical assets of our logistics and marketing business primarily consist of:

- approximately 225 transport trucks, 370 trailers and 190 railcars for transporting NGLs;
- our TexPan liquids railcar facility near Pampa, Texas; and
- an approximately 40-mile crude oil pipeline and associated crude oil storage facility near Mayersville, Mississippi, including a crude oil barge loading facility located on the Mississippi River;

We also enter into agreements with various third parties to obtain natural gas and NGL supply, transportation, gas balancing, fractionation and storage capacity in support of the logistics and marketing services we provide to our gathering, processing and transportation business and to third-party customers. These agreements provide our logistics and marketing business with the following:

- up to approximately 79,000 Bpd of firm NGL fractionation capacity;
- approximately 3.5 Bcf of firm natural gas storage capacity;
- approximately 0.75 Bcf of interruptible natural gas storage capacity;
- up to approximately 30,000 Bpd in 2014 to 120,000 Bpd in 2022 of firm NGL transportation capacity on the Texas Express NGL system;
- up to approximately 89,000 Bpd of additional NGL transportation capacity, a significant portion of which is firm capacity, through transportation and exchange agreements with three NGL pipeline transportation companies; and
- approximately 6.0 million barrels of liquids, or MMBbls, of firm NGL storage capacity.

Customers. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from our gathering, processing and transportation business as well as from third-party pipeline systems and processing plants and sells and delivers them to third-party customers. Most of the third-party customers of our logistics and marketing operations are wholesale customers, such as refiners and petrochemical producers, fractionators, propane distributors and industrial, utility and power plant customers. In addition, we sell natural gas and NGLs to marketing companies at various market hubs.

Supply and Demand. Supply for our logistics and marketing business depends to a large extent on the natural gas reserves, associated natural gas from crude oil development, and rate of drilling within the areas served by our gathering, processing and transportation business. Demand is typically driven by weather-related factors with respect to power plant and utility customers and industrial demand.

Since major market hubs for natural gas and NGLs are located in the Mid-Continent and Gulf Coast regions of the United States and our logistics and marketing business assets are geographically located within Texas, Louisiana, Oklahoma, Kansas and Mississippi, the majority of activities conducted by our logistics and marketing business are conducted within those states. However, our logistics and marketing assets, including our firm transportation capacity and firm natural gas storage capacity, are able to provide us and third parties with access to markets outside of the Mid-Continent and Gulf Coast regions in order to respond to market demand and to realize enhanced value from favorable pricing differentials. Additionally, our firm transportation capacity and our fleet of trucks, trailers and railcars mitigates the risk that our natural gas and NGLs will be shut in by capacity constraints on downstream NGL pipelines and other facilities.

One of the key components of our logistics and marketing business is our natural gas and NGL purchase and resale business. Through our natural gas and NGL purchase and resale operations, we can efficiently manage the transportation and delivery of natural gas and NGLs from our gathering, processing and transportation assets and deliver them through major natural gas transportation pipelines to industrial, utility and power plant customers, as well as to marketing companies at various market hubs throughout the Mid-Continent, Gulf Coast and Southeast regions of the United States. We typically price our sales based on a published daily or monthly price index. In addition, sales to wholesale customers include a pass-through charge for costs of transportation and additional margin to compensate us for the associated services we provide.

Our logistics and marketing business also uses third-party storage facilities and pipelines for the right to store natural gas and NGLs for various periods of time under firm storage, interruptible storage or parking and lending services in order to mitigate risk associated with sales and purchase contracts. We also contract for third-party pipeline capacity under firm transportation contracts for which the pipeline capacity depends on volumes of natural gas from our natural gas assets. We contract this pipeline capacity for various lengths of time and at rates that allow us to diversify our customer base by expanding our service territory. We have also entered into multiple long-term fractionation contracts with third-party fractionators to provide access to fractionation capacity for our customers.

Competition. Our logistics and marketing business has numerous competitors, including large natural gas and NGL marketing companies, marketing affiliates of pipelines, major oil, natural gas and NGL producers, other trucking, railcar and pipeline operations, independent aggregators and regional marketing companies. Our logistics and marketing business' principal competitors include numerous natural gas and NGL marketing companies and major integrated oil and natural gas companies.

Seasonality

Demand for our gathering, processing and transportation services primarily depends upon the supply of natural gas, NGL, condensate, and crude oil production and the drilling rate for new wells. The drilling activities of producers within our areas of operations generally do not vary materially by season but may be affected by adverse weather. Supply for our logistics and marketing operations depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our gathering, processing and transportation business. Generally, the demand for natural gas and NGLs decreases during the spring and fall months and increases during the winter months and, in some areas, during the summer months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. Demand for natural gas with respect to power plant and utility customers is typically driven by weather-related factors.

REGULATION

Regulation of Intrastate Natural Gas Pipelines

Our operations in Texas are subject to regulation under the Texas Utilities Code and the Texas Natural Resources Code, as implemented by the Texas Railroad Commission, or TRRC. Generally, the TRRC is vested with authority to ensure that rates charged for natural gas sales and transportation services are just and reasonable. The rates we charge for transportation services are deemed just and reasonable under Texas law, unless challenged in a complaint. We cannot predict whether such a complaint may be filed against us or whether the TRRC will change its method of regulating rates. The Texas Natural Resources Code provides that an Informal Complaint Process that is conducted by the TRRC shall apply to any rate issues associated with gathering or transmission systems, thus subjecting the gathering and/or intrastate pipeline activities of Enbridge to the jurisdiction of the TRRC via its Informal Complaint Process.

In Oklahoma, intrastate natural gas pipelines and gathering systems are subject to regulation by the Oklahoma Corporation Commission, or OCC. Specifically, the OCC is vested with the authority to prescribe and enforce rates for the transportation and transmission of natural gas. These rates may be amended or altered at any time by the OCC. However, a company affected by a rate change will be given at least ten days' notice in order to introduce evidence of opposition to such amendment. Adjustment of claims or settlement of controversies regarding rates between transportation/transmission companies and employees or patrons will be mediated by the OCC. A corporation is subject to the OCC for failure to comply with rate requirements, resulting in contempt proceedings instituted by any affected party.

Regulation by the FERC of Intrastate Natural Gas Pipelines

Our Texas and Oklahoma intrastate pipelines are generally not subject to regulation by the Federal Energy Regulatory Commission, or FERC. However, to the extent our intrastate pipelines transport natural gas in interstate commerce, the rates, terms and conditions of such transportation are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. One of our intrastate pipelines filed new rates with FERC and received approval in 2014. In addition, under FERC regulations we are subject to market manipulation and transparency rules. This includes the annual reporting requirements pursuant to FERC Order No. 735 *et al*. Failure to comply with FERC's rules, regulations and orders can result in the imposition of administrative, civil and criminal penalties.

Natural Gas Gathering Regulation

Section 1(b) of the Natural Gas Act of 1938, or NGA, exempts natural gas gathering facilities from the jurisdiction of the FERC. We own certain natural gas facilities that we believe meet the traditional tests the FERC has used to establish a facility's status as a gatherer not subject to FERC jurisdiction. However, to the extent our gathering systems buy and sell natural gas, such gatherers, in their capacity as buyers and sellers of natural gas, are now subject to FERC Order 704 and subsequent reissuances of the Order (currently Order 704-C). State regulations of gathering facilities typically address the safety and environmental concerns involved in the design, construction, installation, testing and operation of gathering facilities. In addition, in some circumstances, nondiscriminatory requirements are also addressed; however, historically rates have not fallen under the purview of state regulations for gathering facilities. Many of the producing states have previously adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access or perceived rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to significant and unduly burdensome state or federal regulation of rates and services.

NGL Pipeline Regulation

The mainline and gathering portions of Texas Express are common carriers subject to the regulation by various federal agencies and/or the TRRC. The FERC regulates the interstate pipeline transportation of crude oil, petroleum products, and other liquids such as NGL's, collectively called "petroleum pipelines." The FERC regulates these operations pursuant to the Interstate Commerce Act, or ICA, and the Energy Policy Act of 1992, or EP Act of 1992. The ICA and its implementing regulations require that tariff rates for interstate service on petroleum pipelines be just and reasonable and must not be unduly discriminatory or confer undue preference on any shipper.

The EP Act of 1992 required the FERC to establish a simplified and generally applicable ratemaking methodology for interstate petroleum pipelines. As a result, the FERC adopted an indexed rate methodology. If the rate level on Texas Express Pipeline were subject to formal review or challenge before the FERC, Texas Express would be required to produce a traditional cost of service review justifying its revenues or demonstrate it lacks significant market power.

Two of our other NGL lines, which do not provide service to third parties, operate under FERC-granted waivers from the reporting requirements of Sections 6 and 20 of the ICA. These waivers are effective until a third party shipper requests service. In addition, certain of our NGL lines are subject to regulation as a common carrier by the TRRC. The TRRC's jurisdiction extends to both rates and pipeline safety. The rates we charge for NGL transportation service are deemed just and reasonable under Texas law unless challenged by a complaint. Complaints to state agencies have been infrequent and are usually informally resolved. Although we cannot assure you that our intrastate rates would ultimately be upheld if challenged, we believe that, given this history, the tariffs now in effect are not likely to be challenged or, if challenged, are not likely to be ordered to be reduced.

Safety Regulation and Environmental

General

Our transmission and gathering pipelines, storage and processing facilities, trucking and railcar operations are subject to extensive federal and state environmental, operational and safety regulation. The added costs imposed by regulations are generally no different than those imposed on our competitors. The failure to comply with such rules and regulations can result in substantial penalties and/or enforcement actions and added operational costs.

Pipeline Safety and Transportation Regulation

Some of our natural gas pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, pursuant to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Pipeline Safety Improvement Act of 2002, or PSIA, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or the PIPES Act. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas, or HCAs. Our NGL pipelines, our crude oil pipeline and our propylene pipeline are subject to regulation by PHMSA under the Hazardous Liquid Pipeline Safety Act of 1979, or the HLPSA, which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the transportation of hazardous liquids by pipeline, and the Pipeline Safety Act of 1992, or the PSA, which added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain "regulated gathering lines," and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in HCAs, defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In 1996, Congress enacted the Accountable Pipeline Safety and Partnership Act of 1996, or the APSA, which limited the operator identification requirement to operators of pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline rupture would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage, and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the PIPES Act, Congress required mandatory inspections for certain U.S. crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management.

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

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

Although many of our pipeline facilities are not classified as transmission pipelines and currently are not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with our transmission pipelines on an annual basis as required by existing United States Department of Transportation, or DOT, regulations and their state counterparts. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, should we fail to comply with DOT or comparable state regulations, we could be subject to penalties and fines. If future DOT pipeline integrity management regulations were to require that we expand our integrity management program to currently unregulated pipelines, including gathering lines, costs associated with compliance may have a material effect on our operations.

Recently enacted pipeline safety legislation, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the 2011 Pipeline Safety Act, reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. The PHMSA finalized a rule increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after January 3, 2012 to $200,000 per violation per day, with a maximum of $2,000,000 for a related series of violations. The PHMSA recently issued a final rule applying safety regulations to certain rural low-stress hazardous liquid pipelines that were not covered previously by some of its safety regulations. The PHMSA has also published advanced notice of proposed rulemakings to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. PHMSA also recently published an advisory bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. We have performed hydrotests of our facilities to confirm the maximum allowable operating pressure and do not expect that any final rulemaking by PHMSA regarding verification of maximum allowable operating pressure would materially affect our operations or revenue.

The National Transportation Safety Board has recommended that the PHMSA make a number of changes to its rules, including removing an exemption from most safety inspections for natural gas pipelines installed before 1970. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our operations, particularly by extending through more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations.

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

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

When hydrocarbons are released into the environment or violations identified during an inspection, PHMSA may issue a civil penalty or enforcement action, which can require internal inspections, pipeline pressure reductions and other methods to manage or verify the integrity of a pipeline in the affected area. In addition, the National Transportation Safety Board may perform an investigation of a significant accident to determine the probable cause and issue safety recommendations to prevent future accidents.

We believe that our pipeline, trucking and railcar operations are in substantial compliance with applicable operational and safety requirements. In instances of non-compliance, we have taken actions to remediate the situations. Nevertheless, significant operating expenses and capital expenditure could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of our current pipeline control system or other safety equipment.

Environmental Regulation

General. Our operations are subject to complex federal, state and local laws and regulations relating to the protection of health and the environment, including laws and regulations that govern the handling, storage and release of crude oil and other liquid hydrocarbon materials or emissions from natural gas compression facilities. As with the pipeline and processing industry in general, complying with current and anticipated environmental laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position since the operations of our competitors are generally similarly affected.

In addition to compliance costs, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, injunctions banning or delaying certain activities. We believe that our operations are in substantial compliance with applicable environmental laws and regulations.

There are also risks of accidental releases into the environment associated with our operations, such as releases or spills of crude oil, liquids, natural gas or other substances from our pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines, penalties or damages for related violations of environmental laws or regulations.

Although we are entitled, in certain circumstances, to indemnification from third parties for environmental liabilities relating to assets we acquired from those parties, these contractual indemnification rights are limited, and accordingly, we may be required to bear substantial environmental expenses. However, we believe that through our due diligence process, we identify and manage substantial issues.

Air and Water Emissions. Our operations are subject to the Clean Air Act, or CAA, and the Clean Water Act, or CWA, and comparable state and local statutes. We anticipate, therefore, that we will incur costs in the next several years for air pollution control equipment and spill prevention measures in connection with maintaining existing facilities and obtaining permits and approvals for any new or acquired facilities. The operations of our pipeline facilities are subject to the Environmental Protection Agency's, or EPA, Spill Prevention, Control, and Countermeasures Rule and we are currently in full compliance. Our facilities subject to existing EPA Greenhouse Gas Reporting rules have reported emissions prior to the annual filing deadlines. The EPA has recently signed proposed rules that would subject gathering and booster stations to the Greenhouse Gas Reporting Rule, Subpart W regulations. Although these proposed regulations would increase the recordkeeping and reporting requirements, the increased burden would not be different than that imposed on our competitors. On October 31, 2014, the Texas State Implementation Plan now has the authority to regulate greenhouse gas emissions and approve Greenhouse Gas Prevention of Significant Deterioration, or GHG PSD, permits in Texas. This new approval authority should simplify the GHG PSD permitting process in Texas. On November 10, 2014, the EPA rescinded a Federal Implementation Plan, or FIP, for Texas for GHG PSD permitting.

On August 23, 2011, the EPA proposed the New Source Performance Standards, or NSPS, Subpart OOOO and NESHAP HHH, for volatile organic compounds, or VOC, and sulfur dioxide, or SO2, emissions from the Oil and Natural Gas Sector. The final standards were published and became effective on August 16, 2012. The compliance dates range from October 15, 2012 to October 15, 2013, dependent on the affected equipment. The EPA amended the rule to extend compliance dates for certain storage vessels on August 2, 2013, and may issue additional revised rules in the future. There will be additional costs across the industry to attain compliance with the NSPS, Subpart OOOO, but we do not expect a material effect on our financial statements. On November 26, 2014, the EPA announced its intentions to strengthen air quality standards to within a range of 65 to 70 parts per billion, or ppb, for ozone. The EPA last updated these standards in 2008, then setting them at 75 ppb. If this new, more stringent standard is finalized, numerous counties will fall into the non-attainment category, resulting in more costly pollution control requirements.

The Oil Pollution Act, or OPA, was enacted in 1990 and amends parts of the CWA and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, we could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from our facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements for many of our non-pipeline facilities, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or release. For our liquid pipeline facilities, the OPA imposes requirements for emergency plans to be prepared, submitted and approved by the DOT. For our non-transportation facilities, such as storage tanks that are not integral to pipeline transportation system, the OPA regulations are promulgated by the EPA. We believe that we are in material compliance with these laws and regulations.

Hazardous Substances and Waste Management. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA (also known as the "Superfund" law) and similar state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of waste disposal sites and companies that disposed or arranged for disposal of hazardous substances found at such sites. We may generate some wastes that fall within the definition of a "hazardous substance." We may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required to clean up and restore sites at which such wastes have been disposed. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. We have not received any notification that we may be potentially responsible for material cleanup costs under CERCLA or similar state laws.

Site Remediation. We own and operate a number of pipelines, gathering systems, storage facilities and processing facilities that have been used to transport, distribute, store and process natural gas and other petroleum products. Many of our facilities were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under our control. The age of the facilities, combined with the past operating and waste disposal practices, which were standard for the industry and regulatory regime at the time, have resulted in soil and groundwater contamination at some facilities due to historical spills and releases. Such contamination is not unusual within the natural gas and petroleum industry. Historical contamination found on, under or originating from our properties may be subject to CERCLA, the Resource Conservation & Recovery Act and analogous state laws as described above.

Under these laws, we could incur substantial expense to remediate such contamination, including contamination caused by prior owners and operators. In addition, our General Partner could also be liable for such costs to the extent that we are unable to fulfill our obligations. We have conducted site investigations at some of our facilities to assess historical environmental issues, and we are currently addressing soil and groundwater contamination at various facilities through remediation and monitoring programs, with oversight by the applicable governmental agencies where appropriate.

EMPLOYEES

We are managed and operated by the board of directors and executive officers of our General Partner. Neither we nor our subsidiaries have any employees. Our General Partner is responsible for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our General Partner. We believe that our General Partner and its affiliates have a satisfactory relationship with those employees.

INSURANCE

Our operations are subject to many hazards inherent in the midstream industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. We are insured under the comprehensive insurance program that is maintained by Enbridge for its subsidiaries through the policy renewal date of May 1, 2015, which includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry. The insurance coverage also includes property insurance coverage on our assets that includes earnings interruption resulting from an insurable event, except for pipeline assets that are not located at water crossings. In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement the Partnership has entered into with EEP, Enbridge and other Enbridge subsidiaries.

The coverage limits and deductible amounts at December 31, 2014, for our insurance policies:

Insurance Type	Coverage Limits	Deductible Amount
	(in millions)	
Property and business interruption	Up to $860.0	$10.0
General liability	Up to $700.0	$ 0.1
Pollution liability (as included under General Liability)	Up to $700.0	$30.0

We can make no assurance that the insurance coverage we maintain will be available or adequate for any particular risk or loss or that we will be able to maintain adequate insurance in the future at rates we consider reasonable. Although we believe that our assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on our financial position, results of operations and cash flows.

TAXATION

We are not a taxable entity for U.S. federal income tax purposes. Generally, U.S. federal and state income taxes on our taxable income are borne by our individual partners through the allocation of our taxable income. In a limited number of states, an income tax is imposed upon us and generally, not our individual partners. The income tax that we bear is reflected in our consolidated financial statements. The allocation of taxable income to our individual partners may vary substantially from net income reported in our consolidated statements of income.

AVAILABLE INFORMATION

We make available free of charge on or through our Internet website *http://www.midcoastpartners.com* our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements, and if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not part of this report.

Item 1A. Risk Factors

We encourage you to read the risk factors below in connection with the other sections of this Annual Report on Form 10-K.

Risks Related to our Business

We may not generate sufficient distributable cash flow to support the payment of the minimum quarterly distribution, or any distribution, to our unitholders.

We may not generate sufficient distributable cash flow each quarter to support the payment of the targeted minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the volume of natural gas and NGLs we gather and transport and the volume of natural gas we process and treat and NGLs we fractionate;
- the volume of natural gas, NGLs, and condensates associated with crude oil drilling;
- the level of production of natural gas and the resultant market prices of natural gas and NGLs;
- realized pricing impacts on our revenue and expenses that are directly subject to commodity price exposure;
- the market prices of natural gas and NGLs relative to one another, which affects our processing margins;
- capacity charges and volumetric fees associated with our transportation services;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies in our geographic markets;

- our operating, maintenance and general and administrative costs, including reimbursements to our General Partner and its affiliates;
- regulatory action affecting the supply of, or demand for, natural gas, the maximum transportation rates we can charge on our pipelines, our existing contracts, our operating costs or our operating flexibility;
- damage to pipelines, facilities, plants, related equipment and surrounding properties caused by hurricanes, earthquakes, floods, fires, severe weather, explosions and other natural disasters and acts of terrorism, including damage to third party pipelines or facilities upon which we rely for transportation services;
- outages at the processing, treating or fractionation facilities owned by us or third parties caused by mechanical failure and maintenance, construction and other similar activities;
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise;
- new legislative and regulatory requirements regarding environment and safety that could result in increased capital expenditures and operating costs, reduce demand for our services or otherwise interrupt our natural gas and NGL supply, which may adversely impact our cash flows and results of operations; and
- prevailing economic and market conditions.

In addition, the actual amount of distributable cash flow we generate will also depend on other factors, some of which are beyond our control, including:

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

Our financial performance could be adversely affected if our assets are used less. Any decrease in the volumes of natural gas or NGLs that we gather or transport or in the volumes of natural gas that we process and treat, or NGLs that we fractionate, could adversely affect our financial condition, results of operations and cash flows.

Our financial performance depends to a large extent on the volumes of natural gas and NGLs processed, treated, fractionated and transported on our systems. Decreases in the volumes processed, treated, fractionated and transported by our systems can directly and adversely affect our revenues and results of operations. These volumes can be influenced by factors beyond our control, including:

- environmental or other governmental regulations;
- competition;
- weather conditions;
- storage levels;
- alternative energy sources;
- decreased demand for natural gas and NGLs;

- fluctuations in commodity prices, including the price of natural gas and NGL prices;
- economic conditions;
- supply disruptions;
- availability of supply connected to our systems; and
- availability and adequacy of infrastructure to move, treat and process supply into and out of our systems.

The volumes of natural gas and NGLs processed, treated, fractionated and transported on our systems also depends on the supply of natural gas, NGLs, and condensate from the producing regions that supply these systems. Supply of natural gas 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 our systems, we must obtain new sources of natural gas. The primary factors affecting our ability to obtain non-dedicated sources of natural gas include (1) the level of successful drilling activity in our areas of operation, (2) our ability to compete for volumes from successful new wells and (3) our ability to compete successfully for volumes from sources connected to other pipelines. We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, levels of reserves, availability of drilling rigs and other costs of production and equipment. In addition, existing customers may not extend their contracts for a variety of reasons, including a decline in the availability of natural gas from the Mid-Continent, United States Gulf Coast and East Texas producing regions or if the cost of transporting natural gas from other producing regions through other pipelines into the markets served by our systems were to render the delivered cost of natural gas or NGLs on our systems uneconomical. If we are unable to find additional customers to replace lost demand or transportation fees, or if we are unable to find new sources of supply to maintain the current levels of throughput on our systems, our financial condition, results of operations, cash flows and ability to make cash distributions to our unitholders could be materially and adversely affected.

Natural gas and liquid hydrocarbon prices are volatile, and a change in these prices in absolute terms, or an adverse change in the prices of natural gas and liquid hydrocarbons relative to one another, could adversely affect our total segment margin and cash flow and our ability to make cash distributions to our unitholders.

We are subject to risks due to frequent and often substantial fluctuations in commodity prices. The prices of natural gas, liquid hydrocarbons and other commodities have been extremely volatile, and we expect this volatility to continue. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration. For example, if there is a significant change in the relative prices of NGLs, condensate, crude oil, and/or natural gas, it will impact our processing margins, which are a significant component of our ability to generate cash for distribution to our unitholders.

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

- the levels of domestic production and consumer demand;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation;
- fluctuations in demand from electric power generators and industrial customers;

- the anticipated future prices of oil, natural gas, NGLs and other commodities;
- worldwide political events, including actions taken by foreign oil and natural gas producing nations;
- worldwide weather events and conditions, including natural disasters and seasonal changes; and
- worldwide economic conditions.

Margins we would have realized from processing activities under certain of our percentage-of-liquids contracts may be reduced if we are unable to process a portion of the natural gas under these contracts.

Under certain of our percentage-of-liquids contracts, we have guaranteed a fixed recovery of NGLs to our customers. To the extent that the volumes of natural gas delivered to us exceed the processing capacity of our processing plants, we may have to pay those customers the fully processed value of their natural gas even though we were unable to process a portion of their natural gas due to capacity limitations, which could reduce the margins we would have otherwise realized from processing activities under these contracts.

Commodity price volatility and risks associated with our hedging activities could adversely affect our cash flow and our ability to make cash distributions to our unitholders.

The prices of natural gas, NGLs and crude oil are inherently volatile, and we expect this volatility will continue. We buy and sell natural gas, NGLs and crude oil in connection with our marketing activities. Our exposure to commodity price volatility is inherent to our natural gas, NGLs and crude oil purchase and resale activities, in addition to our natural gas processing activities. For 2015, we expect approximately 47% of our gross margin to be attributable to contracts with some degree of direct commodity price exposure.

To the extent that we engage in hedging activities to reduce our commodity price exposure, we may be prevented from realizing the full benefits of price increases above the level of the hedges. However, because we are not fully hedged, we will continue to have commodity price exposure on the unhedged portion of the commodities we receive in-kind as payment for our gathering, processing, treating and transportation services. As a result of this unhedged exposure, a substantial decline in the prices of these commodities could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Additionally, our hedging activities may not be as effective as we intend in reducing the volatility of our future cash flows. Our hedging activities can result in substantial losses if hedging arrangements are imperfect or ineffective and our hedging policies and procedures are not followed properly or do not work as intended. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under the contracts, particularly during periods of weak and volatile economic conditions. In addition, certain of the financial instruments we use to hedge our commodity risk exposures must be accounted for on a mark-to-market basis. This causes periodic earnings volatility due to fluctuations in commodity prices.

Competition may materially and adversely affect our business and results of operations.

We face competition in our gathering, processing and transportation business, as well as in our marketing and logistics business. Some of our competitors are larger companies that have greater financial, managerial and other resources than we do. Our competitors may expand or construct gathering, processing or transportation systems that would create additional competition for the services we provide to our customers. In addition, many of the large wholesale customers served by our natural gas systems have multiple pipelines connected or adjacent to their facilities. Thus, many of these wholesale customers have the ability to purchase natural gas directly from a number of pipelines or from third parties that may hold capacity on other pipelines. Most natural gas producers and owners have alternate gathering and processing facilities available to them. In addition, they have other alternatives, such as building their own gathering facilities or, in some cases, selling their natural gas supplies without processing. Some of our natural gas and NGL marketing competitors have greater financial resources and access to larger supplies of natural gas than those available to us, which could allow those competitors to price their services more aggressively than we do. All of these competitive factors could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

If we fail to balance our purchases of natural gas and our sales of residue gas and NGLs, our exposure to commodity price risk will increase.

We may not be successful in balancing our purchases of natural gas and our sales of residue gas and NGLs. In addition, a producer could fail to deliver promised volumes to us or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause an imbalance between our purchases and sales. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

Our natural gas assets are primarily located in Texas and Oklahoma. Due to our lack of geographic diversification, adverse developments in our existing areas of operation could materially adversely impact our financial condition, results of operations and cash flows and reduce our ability to make cash distributions to our unitholders.

Our natural gas assets are primarily located in Texas and Oklahoma and we intend to focus our future capital expenditures largely on developing our business in these areas. As a result, our financial condition, results of operations and cash flows depend upon the demand for our services in these regions. Due to our lack of geographic diversity, adverse developments in our current segment of the midstream industry or our existing areas of operation could have a significantly greater impact on our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders than if our operations were more diversified.

Future construction and development costs could exceed our forecast, and our cash flow from construction and development projects may not be immediate, which may limit our ability to make cash distributions to our unitholders.

Our strategy to grow our business contemplates significant expenditures for the development, construction or other acquisition of energy infrastructure assets. The construction of new assets involves numerous regulatory, environmental, legal, political, materials and labor cost and operational risks that are difficult to predict and beyond our control. As a result, we may not be able to complete our projects at the costs estimated or within the time periods we have projected. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional equity.

Any or all of these methods may not be available when or in the amounts needed or may adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Our revenues and cash flows may not increase immediately following our expenditure of funds on a particular project. For example, if we build a new pipeline or expand an existing facility, the design, construction, development and installation may occur over an extended period of time and we may not receive any material increase in revenue or cash flow from that project until after it is placed in service and customers begin using the systems. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays or other factors, we may not meet our obligations as they become due, and we may need to reduce or reprioritize our capital budget, sell non-strategic assets, access the capital markets or reassess our level of distributions to unitholders to meet our capital requirements.

Our growth strategies may be unsuccessful if we incorrectly predict operating results, or are unable to identify and complete future acquisitions or organic growth projects and integrate acquired or developed assets or businesses.

The acquisition and development of complementary midstream assets are components of our growth strategy. Acquisitions and organic growth projects present various risks and challenges, including:

- inability to identify attractive acquisition candidates or negotiate acceptable purchase agreements;
- mistaken assumptions about future prices, volumes, revenues and costs, future results of operations or expected cost reductions or other synergies expected to be realized;
- a decrease in liquidity as a result of utilizing significant amounts of available cash or borrowing capacity to finance an acquisition or organic growth project;
- the loss of critical customers or employees at an acquired business;
- the assumption of unknown liabilities for which we may not be fully and adequately indemnified or insured;
- the risk of failing to effectively integrate the operations or management of acquired assets or businesses or a significant delay in such integration; and
- diversion of management's attention from existing operations.

In addition, we may be unable to identify acquisition targets and consummate acquisitions in the future. A portion of our strategy to grow our business and increase distributions to our unitholders is dependent on our ability to make acquisitions that result in an increase in distributable cash flow. The acquisition component of our growth strategy is based, in large part, on our expectation of ongoing divestitures by EEP of portions of its remaining ownership interest in Midcoast Operating to us over the next four to five years. We do not know when or if any such additional interests will be offered to us to purchase. The consummation and timing of any future acquisitions of these interests will depend upon, among other things, EEP's willingness to offer these interests for sale to us, our ability to negotiate acceptable purchase agreements with respect to the interests and our ability to obtain financing on acceptable terms, and we can offer no assurance that we will be able to successfully consummate any future acquisition of additional interests in Midcoast Operating. Furthermore, if EEP reduces its ownership interest in us, it may be less willing to sell its remaining ownership interest in Midcoast Operating to us. In addition, there are no restrictions on EEP's ability to transfer its ownership interest in Midcoast Operating to a third party.

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

We gather, purchase, process, treat, compress, transport and sell most of the natural gas and NGLs on our systems under contracts with terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with fixed-fee or fixed-spread contracts may desire to enter into gathering and transportation contracts under different fee arrangements, or a producer with whom we have a natural gas purchase contract may choose to enter into a transportation contract with us and retain title to its natural gas. In particular, a significant processing contract on our Anadarko system terminated in the third quarter of 2013. To the extent we are unable to renew or replace our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders could be materially and adversely affected.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our financial condition, results of operations and cash flows.

Some of our customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets or reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could materially affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, our operations and financial results could be adversely affected. In addition, total insurance coverage for multiple insurable incidents exceeding coverage limits would be allocated by Enbridge on an equitable basis under an insurance allocation agreement.

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

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

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

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates, including EEP. The comprehensive insurance program also includes property insurance coverage on our assets, except pipeline assets that are not located at water crossings, and earnings interruption resulting from an insurable event. In the unlikely event that multiple insurable incidents occur that exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the participating Enbridge entities on an equitable basis based on an insurance allocation agreement that we entered into with EEP, Enbridge and another Enbridge subsidiary.

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

Our natural gas and NGL gathering and transportation pipelines and natural gas processing and treating facilities and NGL fractionation facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of such third-party pipelines, processing plants, fractionation facilities and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities become unable to receive, transport or process natural gas, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our segment margin and ability to make cash distributions to our unitholders could be adversely affected. For example, following Hurricane Ike in 2008, the Mont Belvieu fractionation complex was shut down for a period of time due to loss of power. This shut down impacted our ability to process natural gas during the period at certain of our processing plants.

Our ability to access capital markets and credit on attractive terms to obtain funding for our capital projects and acquisitions may be limited.

Our ability to fund our capital projects and make acquisitions depends on whether we can access the necessary financing to fund these activities. Domestic and international economic conditions affect the functioning of capital markets and the availability of credit. Adverse economic conditions, such as those that became prevalent during the recessionary period of 2008 and continued through much of 2010, periodically result in weakness and volatility in the capital markets, which in turn can limit, temporarily or for extended periods, our ability to raise capital through equity or debt offerings. Additionally, the availability and cost of obtaining credit commitments from lenders can change as economic conditions and banking regulations reduce the credit that lenders have available or are willing to lend. These conditions, along with significant write-offs in the financial services sector and the re-pricing of market risks, can make it difficult to obtain funding for our capital needs from the capital markets on acceptable economic terms. As a result, we may revise the timing and scope of these projects as necessary to adapt to prevailing market and economic conditions or ability to make distributions.

Due to these factors, we cannot be certain that funding for our capital needs will be available from bank credit arrangements or capital markets on acceptable terms, if needed and to the extent required. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions and construction projects, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

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

In 2013, Midcoast Operating entered into a Financial Support agreement with EEP as the financial services provider, providing for guaranties of, and letters of credit obtained by, EEP on an aggregate amount not to exceed $700.0 million. We also issued $400.0 million of notes in a private placement offering on September 30, 2014. Our existing and future level of debt, as well as Midcoast Operating's future level of debt, could have important consequences to us, including the following:

- our ability and Midcoast Operating'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 funds that we or Midcoast Operating have available for operations, future business opportunities and cash distributions to unitholders will be reduced by that portion of our and Midcoast Operating's respective cash flow required to make interest payments on outstanding debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

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

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

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

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

Our revolving credit facility limits our ability and Midcoast Operating's ability to, among other things:

- incur or guarantee additional debt;
- make distributions on or redeem or repurchase units or other limited partner interests during the continuance of a default;

- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates other than subsidiaries;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of all or substantially all of our or Midcoast Operating's assets.

Our revolving credit facility contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

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

To the extent Midcoast Operating seeks a credit rating and receives less than an investment grade credit rating, or EEP terminates the Financial Support agreement with Midcoast Operating, Midcoast Operating could be required to provide collateral for Midcoast Operating's hedging liabilities.

Currently, Midcoast Operating is party to certain International Swaps and Derivatives Association, Inc., or ISDA®, agreements associated with the derivative financial instruments we use to manage our exposure to fluctuations in commodity prices. These ISDA® agreements require Midcoast Operating to provide assurances of performance if counterparties' exposure to Midcoast Operating exceeds certain levels or thresholds. EEP generally provides letters of credit on Midcoast Operating's behalf to satisfy such requirements. At the close of the Offering, EEP entered into a Financial Support agreement with Midcoast Operating under which, during the term of the agreement, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under derivative agreements and natural gas and NGL purchase agreements. Under the Financial Support agreement, EEP's support of Midcoast Operating's obligations will terminate on the earlier to occur of (1) the fourth anniversary of the closing of the Offering and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in us), less than 20% of the total outstanding limited partner interest in Midcoast Operating.

Without an investment grade credit rating or financial support from EEP, we expect that Midcoast Operating will be required to provide letters of credit, cash collateral or other financial assurance with respect to new derivative agreements or purchase agreements that Midcoast Operating enters into. The amounts of any letters of credit Midcoast Operating provides under the terms of Midcoast Operating's ISDA® agreements or other derivative financial instruments or agreements, or otherwise in support of our operations, would reduce the amount that we are able to borrow under our revolving credit facility. To the extent that EEP no longer provides this financial support or if we were otherwise required to guarantee the obligations currently guaranteed by EEP under the Financial Support agreement, the impact on our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders could be materially and adversely affected.

EEP's credit ratings could adversely affect our ability to grow our business and our ability to obtain credit in the future.

EEP's long-term credit ratings are currently investment grade. Although we do not have any indebtedness rated by any credit rating agency, we may have rated debt in the future. Credit rating agencies will likely consider EEP's debt ratings when assigning ours because of EEP's ownership interest in us and control of our operations. If one or more credit rating agencies were to downgrade the outstanding indebtedness of EEP or us, we could experience an increase in our borrowing costs or difficulty accessing the capital markets. Such a development could adversely affect our financial condition, results of operations and cash flows and our ability to grow our business and to make cash distributions to our unitholders.

Our logistics and marketing operations involve market and regulatory risks.

As part of our logistics and marketing activities, we purchase natural gas and NGLs at prices determined by prevailing market conditions. Following our purchase of natural gas and NGLs, we generally resell the natural gas or NGLs at a higher price under a sales contract that is generally comparable in terms to our purchase contract, including any price escalation provisions. The profitability of our logistics and marketing operations may be affected by the following factors:

- our ability to negotiate on a timely basis commodity purchase and sales agreements in changing markets;
- reluctance of wholesale customers to enter into long-term purchase contracts;
- consumers' willingness to use other fuels when natural gas or NGL prices increase significantly;
- timing of imbalance or volume discrepancy corrections and their impact on financial results;
- the ability of our customers to make timely payment;
- inability to match purchase and sale of natural gas or NGLs on comparable terms; and
- changes in, limitations upon or elimination of the regulatory authorization required for our wholesale sales of natural gas and NGLs in interstate commerce.

Our risk management policies cannot eliminate all risks. In addition, any non-compliance with our risk management policies could result in significant financial losses.

We use derivative financial instruments to manage the risks associated with market fluctuations in commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are associated with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices or interest rates. These policies cannot, however, eliminate all risk of unauthorized trading and other speculative activity. Although this activity is monitored independently by our risk management function, we remain exposed to the risk of non-compliance with our risk management policies. We can provide no assurance that our risk management function will detect and prevent all unauthorized trading and other violations of our risk management policies and procedures, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could result in significant financial losses and have a material adverse effect on our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

Compliance with environmental and operational safety laws and regulations may expose us to material costs and liabilities.

Our pipeline, gathering, processing and trucking operations are subject to federal, state and local laws and regulations relating to environmental protection and operational and worker safety. Numerous governmental authorities have the power to enforce compliance with the laws and regulations they administer and permits they issue, often imposing complex requirements and necessitating capital expenditures or increased operating costs to achieve compliance. Our failure to comply with these laws, regulations and operating permits can result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. Our natural gas gathering, processing and transportation and NGL fractionation operations expose us to the risk of incurring significant environmental and safety-related costs and liabilities. Additionally, operational modifications, including pipeline restrictions, necessary to comply with regulatory requirements and resulting from our handling of natural gas and liquid hydrocarbons, historical environmental contamination, accidental releases or upsets, regulatory enforcement, litigation or safety and health incidents can also result in significant cost or limit revenues and volumes. In addition, environmental and operational safety laws and regulations, including but not limited to pipeline safety, wastewater discharge and air emission requirements, continue to become more stringent over time, particularly those related to the oil and gas industry. We may incur joint and several strict liability under these environmental laws and regulations in connection with discharges or releases of natural gas and liquid hydrocarbons and wastes on, under or from our properties and facilities, many of which have been used for gathering or processing activities for a number of years, often by third parties not under our control. Private parties, including the owners of properties through which our gathering systems pass and facilities where our natural gas and liquid hydrocarbons are handled or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage. We may also incur costs in the future due to changes in environmental and safety laws and regulations, or re-interpretations of enforcement policies or claims for personal, property or environmental damage. We may not be able to recover these costs from insurance or through higher rates.

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

Because our operations, including our processing, treating and fractionation facilities and our compressor stations, are sources of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our facilities, and could delay future permitting. At the federal level, the United States Congress has in the past and may in the future consider legislation to impose a tax on carbon or require a reduction of greenhouse gas emissions. On September 22, 2009, the EPA issued a rule requiring nation-wide reporting of greenhouse gas emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Subsequently, on November 30, 2010, the EPA issued a supplemental rulemaking that expanded the types of industrial sources that are subject to or potentially subject to the EPA's mandatory greenhouse gas emissions reporting requirements to include petroleum and natural gas systems. These regulations were amended by the EPA in November 2014. The EPA has stated, consistent with President Obama's Climate Action Plan, that it intends to establish reporting requirements for methane and other greenhouse gas emissions from the oil and gas sector operations and maintenance activities and adopt amended regulations by the end of 2016 for the sector if further reductions are warranted.

The EPA has concluded that the April 2010 issuance of regulations to control the greenhouse gas emissions from light duty motor vehicles (the "tailpipe rule") automatically triggered provisions of the CAA that, in general, could potentially require stationary source facilities that emit more than 250 tons per year of carbon dioxide equivalent to obtain permits to demonstrate that best practices and technology are being used to minimize greenhouse gas emissions. Under the phased-in approach currently being implemented by the EPA, for most purposes, new permitting provisions to reduce greenhouse gas emissions are required for new major source facilities that emit 100,000 tons per year or more of carbon dioxide equivalent, or CO2e, and existing major source facilities making major modifications that would increase greenhouse gas emissions by 75,000 CO2e. On May 13, 2010, the EPA issued the "tailoring rule," which served to increase the greenhouse gas emissions threshold that triggers the permitting requirements for major new (and major modifications to existing) stationary sources. This rule was upheld by the U.S. Court of Appeals for the District of Columbia Circuit (Coalition for Responsible Regulation v. EPA) and then subsequently revised by the U.S. Supreme Court in 2013 (Utility Air Regulatory Group v. EPA). The 2014 court opinion invalidates the "Tailoring Rule" which purported to establish new PSD applicability thresholds for GHGs in the Clean Air Act. The Court invalidated the EPA's action concluding that the EPA rewriting of the statutory thresholds was impermissible and the EPA has no power to tailor legislations to bureaucratic policy goals by rewriting unambiguous statutory term. The decision was final July 25, 2014. This ruling will render a substantial portion of state GHG permitting rules unnecessary given that no PSD or Title V permit for GHG emissions is even allowable under the federal Clean Air Act.

Pipeline operations involve numerous risks that may adversely affect our business and financial condition.

Operation of complex pipeline systems, gathering, treating, processing and trucking operations involves many risks, hazards and uncertainties. These events include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of the facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, hurricanes, floods, landslides or other similar events beyond our control. These types of catastrophic events could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, any of which could also result in substantial losses for which insurance may not be sufficient or available and for which we may bear a part or all of the cost. Costs of pipeline seepage over time may be mitigated through insurance, however, if not discovered within the specified insurance time period we would incur full costs for the incident. In addition, we could be subject to significant fines and penalties from regulators in connection with such events. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these catastrophic events could be greater.

Our assets vary in age and were constructed over many decades which may cause our inspection, maintenance or repair costs to increase in the future. In addition, there could be service interruptions due to unknown events or conditions, or increased downtime associated with our pipelines that could have a material and adverse effect on our business and results of operations.

Our pipelines vary in age and were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have changed over time. Depending on the era of construction, some assets will require more frequent inspections, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make distributions to our unitholders.

Measurement adjustments on our pipeline system can materially affect our financial condition.

Natural gas and NGL measurement adjustments occur as part of the normal operating conditions associated with our pipelines. The quantification and resolution of measurement adjustments is complicated by several factors including: (1) the significant quantities (i.e., thousands) of measurement meters that we use throughout our systems, primarily around our gathering and processing assets; (2) varying qualities of natural gas and NGLs in the streams gathered and processed through our systems; and (3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement adjustments that can occur on our systems and may materially affect our results of operations.

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

A significant portion of our customers' natural gas production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in Congress. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential impacts of hydraulic fracturing on drinking water resources; the multi-year study's individual research projects began publishing results in 2013 and individual studies are ongoing. In addition, the EPA has announced its intention to regulate wastewater discharges from hydraulic fracturing and other natural gas production activities under the CWA and is scheduled to issue a proposed rule in 2015.

On April 17, 2012, the EPA also approved final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through flaring until 2015, after which reduced emission (or "green") completions must be used. The rules also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants, and certain other equipment. On April 12, 2013, EPA proposed amendments to the rule which would, among other things, provide additional time for recently constructed, modified or reconstructed storage tanks to install emission controls. These rules may require a number of modifications to our customers' and our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our customers, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. For example, on December 13, 2011, the TRRC adopted the Hydraulic Fracturing Chemical Disclosure Rule implementing a state law passed in June 2011, requiring public disclosure of hydraulic fracturing fluid contents for wells drilled under drilling permits issued after February 1, 2012. Certain states, including the State of Texas, also have taken regulatory action in response to increased seismic activity that in certain cases have been connected to hydraulic fracturing. In addition, at least one municipality in a state in which we operate, the City of Denton, Texas, has followed others in adopting bans or severely restricting hydraulic fracturing activities. Litigation concerning this ban, as well as others, is ongoing. We cannot predict whether any other legislation or regulation will be enacted and if so, what its provisions would be. If additional levels of regulation and permits are required through the adoption of new laws and regulations at the federal, state or local level, that could lead to delays, increased operating costs, and prohibitions for producers who drill near our pipelines. These factors could reduce the volumes of natural gas and NGLs available to move through our gathering and other systems, which could materially adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders and results of operations.

Changes in, or challenges to, our rates and other terms and conditions of service could have a material adverse effect on our financial condition and results of operations.

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

The majority of our pipelines are not subject to regulation by the FERC; however, a change in the jurisdictional characterization of our assets, or a change in policy, could result in increased regulation of our assets which could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

The substantial majority of our pipeline assets are gas-gathering facilities or interests in gas-gathering facilities. Unlike interstate gas transportation facilities, natural gas gathering facilities are exempt from the jurisdiction of the FERC under the NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some cases non-discriminatory take requirements and complaint-based rate regulation. Although the FERC has not made a formal determination with respect to all of our facilities, we believe that our natural gas pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

For the delivery of fuel and other products to our customers, we operate a fleet of specialized trucks and delivery equipment. We are therefore subject to regulation as a motor carrier by the DOT and various state agencies. These federal and state regulatory authorities exercise broad powers, generally governing such activities as the authorization to engage in motor carrier operations, driver licensing and insurance requirements, safety, equipment testing and transportation of hazardous materials. Our trucking operations, including the special modifications we make to our equipment and vehicles to operate in remote, rugged or environmentally sensitive areas, are subject to possible regulatory and legislative changes that may increase our costs. Some of these possible changes include increasingly stringent environmental regulations, fuel emissions limits, changes in the hours of service regulations that govern the amount of time a driver may drive or work in any specific period and limits on vehicle weight and size and other matters.

Our gathering systems and intrastate pipelines are subject to state regulation that could materially and adversely affect our operations and cash flows.

State regulation of gathering facilities includes safety and environmental requirements. Several of our gathering systems are also subject to non-discriminatory take requirements and complaint-based state regulation with respect to our rates and terms and conditions of service. State and local regulation may cause us to incur additional costs or limit our operations, may prevent us from choosing the customers to which we provide service, any or all of which could materially and adversely affect our financial condition, results of operations and cash flows and our ability to make cash distributions to our unitholders.

We do not own a majority of the land on which our pipelines are located, which could result in disruptions to our operations.

We do not own a majority of the land on which our pipelines are located, and we are, therefore, subject to the possibility of more onerous terms and increased costs to retain necessary land use if we do not have valid leases or rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies, and some of our agreements may grant us those rights for only a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, financial condition and results of operations and our ability to make cash distributions to our unitholders.

Terrorist or cyber-attacks and threats, escalation of military activity in response to these attacks or acts of war could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, cyber-attacks, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Future terrorist or cyber-attacks, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. We do not maintain specialized insurance for possible liability resulting from a cyber-attack on our assets that may shut down all or part of our business. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

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

In July 2010 federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was enacted. The Dodd-Frank Act provides additional statutory requirements for swap transactions, including energy and interest rate hedging transactions. These statutory requirements must be implemented through regulations, primarily through the Commodity Futures Trading Commission, or the CFTC. To date, the Dodd-Frank Act provisions have not materially changed the way many of our swap transactions are entered into, as we have been able to continue transacting with existing counterparties in over-the-counter markets or with registered exchanges to meet hedging requirements set forth in our risk policies.

The full impact of the Dodd-Frank Act on our hedging activities as an end user is uncertain at this time, as the CFTC has not yet promulgated final regulations implementing some of the key provisions on margining or position limits. We may have new regulatory burdens from these developments in addition to the various business conduct, recordkeeping and reporting rules resulting from the Dodd-Frank Act provisions currently in place. Moreover, longer term, fundamental changes to the swap market as a result of the Dodd-Frank Act requirements could significantly increase the cost of entering into and/or reduce the availability of new or existing swaps.

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

Our ability to operate our business effectively could be impaired if affiliates of our General Partner fail to attract and retain key management personnel.

We depend on the continuing efforts of the executive officers of our General Partner, all of whom are employees of affiliates of EEP’s general partner. Additionally, neither we nor our subsidiaries have employees.

Our General Partner is responsible for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our General Partner, including our President and Principal Executive Officer. The loss of any member of our management or other key employees could have a material adverse effect on our business. Consequently, our ability to operate our business and implement our strategies will depend on the continued ability of affiliates of our General Partner to attract and retain highly skilled management personnel with midstream natural gas industry experience. Competition for these persons in the midstream natural gas industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

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

Risks Inherent in an Investment in Us

EEP owns and controls our General Partner, which has sole responsibility for conducting our business and managing our operations and has limited duties to us and our unitholders. EEP, Enbridge and our General Partner have conflicts of interest with us and they may favor their own interests to the detriment of us and our other unitholders.

EEP, which is controlled by Enbridge Energy Management, L.L.C., or Enbridge Management, through a delegation of control agreement with EEP's general partner, controls our General Partner, and appoints all of the officers and directors of our General Partner, some of whom are also officers or directors of EEP's general partner, Enbridge Management or Enbridge. Although our General Partner has a duty to manage us in a manner that it believes is in the best interests of our partnership and our unitholders, the directors and officers of our General Partner also have a duty to manage our General Partner in a manner that they believe is in the best interests of EEP. Conflicts of interest may arise between EEP, Enbridge and their affiliates, including our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates, including EEP or Enbridge, over our interests and the interests of our common unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires EEP or Enbridge to pursue a business strategy that favors us;
- our General Partner is allowed to take into account the interests of parties other than us, such as EEP and Enbridge, in resolving conflicts of interest;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our General Partner with contractual standards governing its duties limiting our General Partner's liabilities and restricting remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our General Partner has the power and authority to conduct our business without unitholder approval;
- affiliates of our General Partner, including EEP and Enbridge, may compete with us, and neither our General Partner nor its affiliates have any obligation to present business opportunities to us;
- EEP is under no obligation to offer us any additional interests in Midcoast Operating;
- our General Partner will determine the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;

- our General Partner will determine the amount and timing of many of our cash expenditures and whether a cash expenditure is classified as an expansion capital expenditure, which would not reduce operating surplus, or a maintenance capital expenditure, which would reduce operating surplus. This determination can affect the amount of available cash from operating surplus that is distributed to our unitholders and to our General Partner, the amount of adjusted operating surplus generated in any given period and the ability of the subordinated units to convert into common units;
- our General Partner will determine which costs incurred by it are reimbursable by us;
- our General Partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;
- our partnership agreement permits us to classify up to $45.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus and this cash may be used to fund distributions on our subordinated units or to our General Partner in respect of the general partner interest or the incentive distribution rights;
- our partnership agreement does not restrict our General Partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our General Partner intends to limit its liability regarding our contractual and other obligations;
- our General Partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;
- our General Partner controls the enforcement of the obligations that it and its affiliates owe to us;
- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our General Partner may elect to cause us to issue Class B common units to it in connection with a resetting of the target distribution levels related to our General Partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our General Partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

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

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires that we distribute all of our available cash to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Therefore, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we will distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, and we do not anticipate there being limitations in our new credit facility, on our ability to issue additional units, including units ranking senior to the common units as to distribution or liquidation, and our common and subordinated unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any additional units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce our distributable cash flow.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders. However, after the subordination period has ended, our partnership agreement can be amended with the consent of our General Partner and the approval of a majority of the outstanding Class A common units and Class B common units (including Class A common units and Class B common units held by affiliates of our General Partner), voting together as a single class.

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

Prior to making any distributions to our unitholders, we will reimburse our General Partner and its affiliates, including EEP, for expenses they incur and payments they make on our behalf. Our partnership agreement provides that our General Partner will determine in good faith the expenses that are allocable to us. The costs and expenses for which we are required to reimburse our General Partner and its affiliates are not subject to any caps or other limits. The reimbursement of expenses and payment of fees, if any, to our General Partner and its affiliates will reduce the amount of available cash to pay cash distributions to our unitholders.

Because our common units will be yield-oriented securities, increases in interest rates could adversely impact our unit price and our ability to issue equity or incur debt for acquisitions or other purposes.

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

Our partnership agreement replaces our General Partner's fiduciary duties to our limited partners with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary duties to which our General Partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. In addition, our partnership agreement restricts the remedies available to our limited partners for actions that might constitute breaches of fiduciary duty under applicable state law. For example, our partnership agreement permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner. When acting in its individual capacity, our General Partner is entitled to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us or any limited partner. By purchasing a common unit, a unitholder is deemed to have consented to the provisions in our partnership agreement, including the provisions discussed above.

Our partnership agreement limits our General Partner's liabilities and the remedies available to our limited partners for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to our limited partners for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

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

In connection with a situation involving a transaction with an affiliate or a conflict of interest, our partnership agreement provides that any determination by the board of directors or the conflicts committee of the board of directors of our General Partner must be made in good faith and that our conflicts committee and the board of directors of our General Partner are entitled to a presumption that they acted in good faith. In any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

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

Our General Partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled for each of the prior four consecutive fiscal quarters (and the amount of each such distribution did not exceed adjusted operating surplus for each such quarter), to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Furthermore, our General Partner has the right to transfer all or any portion of the incentive distribution rights at any time, and such transferee shall have the same rights as the General Partner relative to resetting target distributions if our General Partner concurs that the tests for resetting target distributions have been fulfilled. Following a reset election by our General Partner, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

In the event of a reset of our minimum quarterly distribution and target distribution levels, our General Partner will be entitled to receive, in the aggregate, a number of Class B common units equal to that number of Class B common units that would have entitled the holder of such units to an aggregate quarterly cash distribution in the two-quarter period prior to the reset election equal to the distribution to our General Partner on the incentive distribution rights in the quarter prior to the reset election prior two quarters. Our General Partner will also be issued the number of General Partner units necessary to maintain its General Partner interest in us that existed immediately prior to the reset election (currently 2.0%). We anticipate that our General Partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per Class A common unit without such conversion; however, it is possible that our General Partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our General Partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our General Partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued Class B common units, which, along with the Class A common units, are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the General Partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. As a result, a reset election may cause holders of our Class A common units and Class B common units to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued Class B common units to our General Partner in connection with resetting the target distribution levels related to our General Partner's incentive distribution rights.

Unitholders have very limited voting rights and even if they are dissatisfied they currently cannot remove our General Partner without its consent.

Unitholders have only limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Unlike holders of stock in a public corporation, unitholders will not have "say-on-pay" advisory voting rights. Unitholders did not elect our General Partner or the board of directors of our General Partners and will have no right to elect our General Partner or the board of directors or our General Partner on an annual or other continuing basis. The directors of our General Partner are chosen by EEP. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The unitholders will be unable initially to remove our General Partner without its consent because our General Partner and its affiliates will own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding Class A common units, Class B common units and subordinated units voting together as a single class is required to remove our General Partner. Our General Partner and its affiliates own approximately 51.9% of the total outstanding Class A common units, Class B common units and subordinated units on an aggregate basis, excluding common units purchased by directors and officers of our General Partner and Enbridge Management under our directed unit program. Also, if our General Partner is removed without cause as defined under our partnership agreement during the subordination period, and common units and subordinated units held by our General Partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into Class B common units and any existing arrearages on the Class A common units will be extinguished. A removal of our General Partner under these circumstances would adversely affect the Class A common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests.

"Cause" is narrowly defined under our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the General Partner liable for actual fraud or willful or wanton misconduct in its capacity as our General Partner. Cause does not include most cases of charges of poor management of the business, so the removal of our General Partner because of the unitholders' dissatisfaction with our General Partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units into Class B common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, cannot vote on any matter.

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

Our General Partner may transfer its General Partner units to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of EEP to transfer its membership interest in our General Partner to a third party. The new owner of our General Partner would then be in a position to replace the directors and officers of our General Partner with its own designees.

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

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

We may issue additional partnership securities without unitholder approval, which would dilute unitholder interests.

At any time, we may issue an unlimited number of additional partnership securities without the approval of our unitholders and our existing unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such limited partner interests. Further, there are no limitations in our partnership agreement on our ability to issue partnership securities that rank equal or senior to our common units as to distributions or in liquidation or that have special voting rights and other rights. The issuance by us of additional common units or other partnership securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash we have available to distribute on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by holders of our common units will increase;

- because the amount payable to holders of incentive distribution rights is based on a percentage of the total cash available for distribution, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

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

As of December 31, 2014, EEP holds 1,335,056 Class A common units and 22,610,056 subordinated units. All of the subordinated units will convert into Class B common units on a one-for-one basis at the end of the subordination period and may convert earlier under certain circumstances. Additionally, we have agreed to provide EEP with certain registration rights under applicable securities laws.

Our General Partner's discretion in establishing cash reserves may reduce the amount of cash we have available to distribute to unitholders.

Our partnership agreement requires our General Partner to deduct from operating surplus the cash reserves that it determines are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our General Partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash we have available to distribute to our unitholders.

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

If at any time our General Partner and its affiliates own more than 80% of our then-outstanding Class A common units, our General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us to acquire all, but not less than all, of the Class A common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of our Class A common units over the 20 trading days preceding the date that is three business days before the General Partner exercises this right and (2) the highest per-unit price paid by our General Partner or any of its affiliates for Class A common units during the 90-day period preceding the date such notice is first mailed. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. Our General Partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of this limited call right. There is no restriction in our partnership agreement that prevents our General Partner from issuing additional Class A common units and exercising its limited call right. If our General Partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

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

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

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

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

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

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

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

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

Our Class A common units are listed on the NYSE. The NYSE does not require us to have, and we do not intend to have, a majority of independent directors on the boards of our General Partner or Enbridge Management, or to establish a compensation committee or nominating and corporate governance committee. In addition, any future issuance of additional Class A common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules that apply to corporations. Accordingly, holders of our Class A common units will not have the same protections afforded to investor owners of certain corporations that are subject to all of the NYSE corporate governance requirements.

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

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

Section 7704 of the Internal Revenue Code of 1986, or the Internal Revenue Code, provides that publicly traded partnerships will, as a general rule, be taxed as corporations. An exception exists, however, with respect to a publicly traded partnership for which 90% or more of the gross income for every taxable year consists of "qualifying income." If less than 90% of our gross income for any taxable year is qualifying income, we will be taxed as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent tax years. Although we do not believe that we will be treated as a corporation for federal income tax purposes based on our current operations, the IRS could disagree with the positions we take. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our distributable cash flow would be substantially reduced.

In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax on our gross income apportioned to Texas.

Imposition of any such taxes may substantially reduce the cash we have available for distribution to you. Therefore, if we were treated as a corporation for federal income tax purposes or otherwise subjected to a material amount of entity-level taxation for state tax purposes, there would be material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that, if a law is enacted that subjects us to taxation as a corporation for federal income tax purposes, the minimum quarterly distribution amount and the target distribution levels will be adjusted to reflect the impact of that law on us.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted. It is possible, however, that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

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

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

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our distributable cash flow to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we have taken or may take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our positions and such positions may not ultimately be sustained. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our distributable cash flow.

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

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

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income, or UBTI, and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. Our counsel is unable to opine as to the validity of such filing positions. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. The U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed Treasury Regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may be required to recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We have adopted certain valuation methodologies for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our General Partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

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

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

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

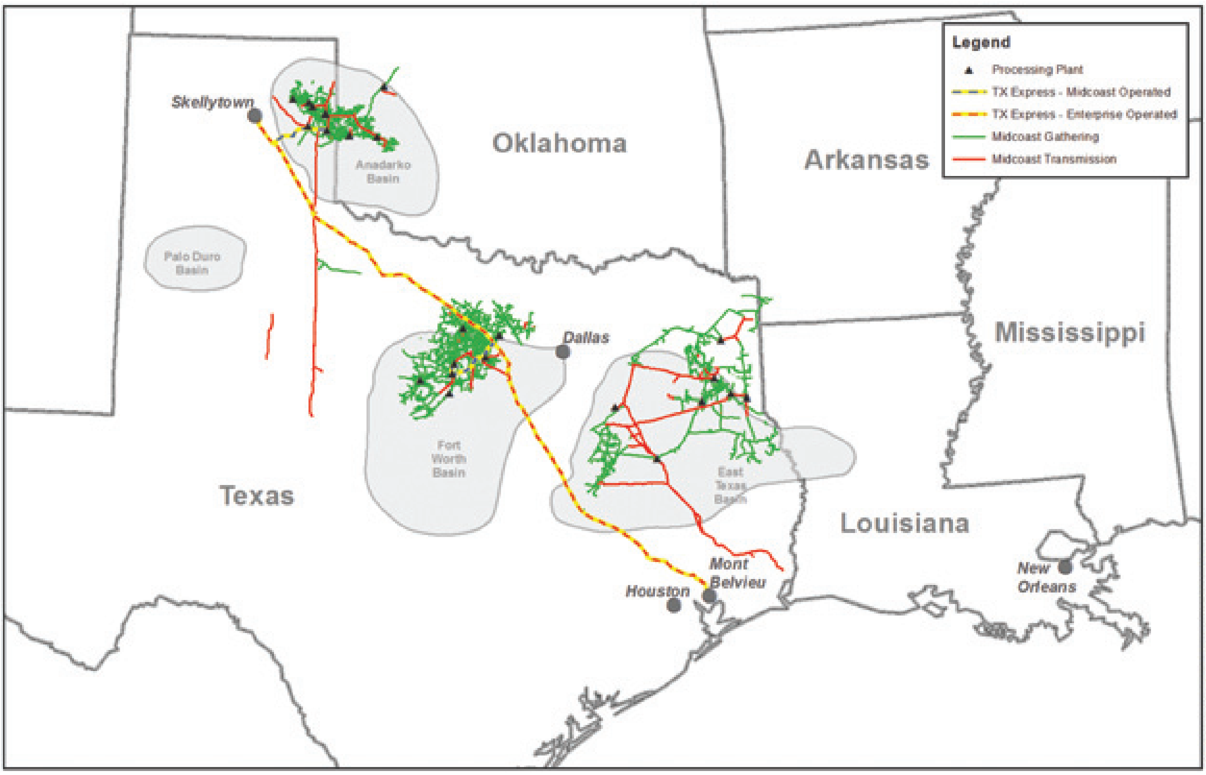
We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple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

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in over 14 states. Most of these states currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units. Please consult your tax advisor.

Item 2. Properties

The map below presents the location of our current natural gas systems assets, projects being constructed and joint ventures. This map also depicts some assets owned or under development by us to provide an understanding of how they relate to our business.



A description of these properties of our natural gas systems are included in Item 1. *Business*, which is incorporated herein by reference.

In general, our systems are located on land owned by others and are operated under perpetual easements and rights-of-way, licenses, leases or permits that have been granted by private land owners, public authorities, railways or public utilities. Our natural gas systems have natural gas compressor stations, processing plants and treating plants, the vast majority of which are located on land that is owned by us, with the remainder used by us under easements, leases or permits.

Titles to our properties acquired in our natural gas systems are subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

Substantially all of our pipelines are constructed on rights-of-way granted by the record owners of the property. In some instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, and state highways and, in some instances, these permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. Although such revocations are unlikely to be exercised, in nearly all instances continued payment of rentals and license fees, or relocations to accommodate a public authority or railroad ensures continued operation of the affected system. In some states and under some circumstances, we have the right of eminent domain to acquire rights-of-way and lands necessary for our common carrier pipelines. Under our omnibus agreement, EEP will indemnify us for any failure to have certain rights-of-way, consents, licenses and permits necessary to own and operate our assets in substantially the same manner that they were owned and operated prior to the Offering. EEP's indemnification obligation will be limited to losses for which we notify EEP prior to November 13, 2016 and will be subject to a $500,000 aggregate deductible before we are entitled to indemnification. EEP's indemnification obligations under the omnibus agreement are subject to a $15.0 million aggregate cap.

Item 3. Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition. The disclosures included in Part II, Item 8. *Financial Statements and Supplementary Data*, under Note 13. *Commitments and Contingencies,* address the matters required by this item and are incorporated herein by reference. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Item 4. Mine Safety Disclosures

None.

PART II

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

Our Class A common units are listed and traded on the NYSE, the principal market for the Class A common units, under the symbol MEP. The quarterly price ranges per Class A common unit for 2014 and 2013 and cash distributions paid per unit for 2014 are summarized as follows:

	First	Second	Third	Fourth
2014 Quarters				
High	$ 22.29	$ 22.93	$ 25.13	$ 23.09
Low	$ 19.16	$ 20.55	$ 18.96	$ 12.50
Cash distributions paid	$0.1664	$0.3125	$0.3250	$0.3375

	First	Second	Third	Fourth
2013 Quarters				
High	$ —	$ —	$ —	$ 20.30
Low	$ —	$ —	$ —	$ 16.96

On February 13, 2015, the last reported sales price of our Class A common units on the NYSE was $14.38. At January 30, 2015, there were approximately 2,634 Class A common unitholders, of which there was approximately one registered Class A common unitholders of record. There is no established public trading market for our subordinated units, all of which are held EEP.

Under our current cash distribution policy, we intend to make a quarterly distribution to the holders of our Class A common units and subordinated units to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including the payment of expenses to our General Partner and its affiliates. Our current cash distribution policy is also subject to certain restrictions, as well as the considerable discretion of our General Partner in determining the amount of our available cash each quarter. These restrictions include restrictions under our Credit Agreement, general partner discretion to establish reserves and to take other actions provided by our partnership agreement, and performance of our subsidiaries. For further information about distributions and about these and other limitations and risks related to distributions, please read Item 1A. *Risk Factors* and Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Distributions.*

ISSUER PURCHASES OF EQUITY SECURITIES

The following table provides information as of December 31, 2013, with respect to Class A common units that were purchased by Midcoast Energy Partners, L.P. from Enbridge Energy Partners. There were no units repurchased in 2014:

Period	Total number of units purchased	Average price paid per unit	Total number of units purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of units that may yet be purchased under the plans or programs
October 1—October 31	—	$ —	—	—
November 1—November 30[1]	2,775,000	$16.94	—	—
December 1—December 31	—	$ —	—	—
Total	2,775,000	$16.94	—	—

(1) Pursuant to the Contribution, Conveyance and Assumption Agreement, dated as of November 13, 2013, by and among EEP, MEP, Midcoast Holdings, Midcoast Operating and Midcoast OLP GP, L.L.C., 2,775,000 Class A common units were purchased by MEP from EEP with the proceeds from the over-allotment option exercise related to the Offering.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data of Midcoast Energy Partners, L.P. and our Predecessor. The table is derived, and should be read in conjunction with, our audited consolidated financial statements and notes thereto included in Item 8. *Financial Statements and Supplementary Data*. See also Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

	December 31,				
	2014	2013	2012[1]	2011[1]	2010[1]
	(in millions, except per unit amounts)				
Income Statement Data:[2]					
Operating revenues	$5,894.3	$5,593.6	$5,357.9	$7,828.2	$6,654.3
Operating expenses	5,741.6	5,528.5	5,186.5	7,608.9	6,497.3
Operating income	152.7	65.1	171.4	219.3	157.0
Interest expense	16.7	1.7	—	—	—
Equity in earnings of joint ventures	13.2	—	—	—	—
Other income (expense)	(0.3)	(1.2)	(0.1)	2.8	3.0
Income tax expense	4.6	8.3	3.8	2.9	2.6
Net income	$ 144.3	$ 53.9	$ 167.5	$ 219.2	$ 157.4
Predecessor income prior to initial public offering (from January 1, 2013 through November 12, 2013	$ —	$ 56.3			
Net loss subsequent to initial public offering to Midcoast Energy Partners, L.P. (from November 13, 2013 through December 31, 2013)	$ —	$ (2.4)			
Net income (loss) attributable to noncontrolling interest	$ 80.2	$ (0.6)			
Net income (loss) attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ 64.1	$ (1.8)			
Net income attributable to limited partner ownership interest[4]	$ 62.8	$ 19.7	$ 64.0	$ 83.8	$ 60.2
Net income per limited partner unit (basic and diluted)[4]	$ 1.39	$ 0.68	$ 2.40	$ 3.14	$ 2.26
Cash distributions paid per limited partner unit outstanding	$ 1.14				
Financial Position Data (at year end):[2][3]					
Property, plant and equipment, net	$4,159.7	$4,082.3	$3,963.0	$3,651.3	$3,320.6
Total assets	5,754.1	6,036.4	5,667.4	5,134.6	4,802.6
Long-term debt, excluding current maturities	760.0	335.0	—	—	—
Partners' capital:					
Predecessor partner interest	—	—	4,707.1	4,277.8	3,994.1
Class A common units	634.2	495.3	—	—	—
Subordinated units	1,174.0	1,035.1	—	—	—
General Partner	47.8	42.2	—	—	—
Accumulated other comprehensive income (loss)	11.6	(3.1)	7.1	(28.7)	(51.4)
Noncontrolling interest	2,529.0	2,983.2	—	—	—
Partners' capital	$4,396.6	$4,552.7	$4,714.2	$4,249.1	$3,942.7
Cash Flow Data:[2][3]					
Cash flows provided by operating activities	$ 159.1	$ 420.9	$ 352.7	$ 415.6	$ 172.4
Cash flows used in investing activities	231.3	522.3	614.5	480.1	984.1
Cash flows provided by financing activities	67.3	106.3	261.8	64.5	811.7
Additions to property, plant and equipment, acquisitions and investment in joint venture included in investing activities, net of cash acquired	274.6	462.9	621.1	484.0	1,002.2

(1) Represents the Predecessor historical information.

(2) Our income statement, financial position and cash flow data reflect the following significant acquisitions and dispositions:

Date of Acquisition / Disposition	Description of Acquisition / Disposition
September 2010	Acquisition of the Elk City system in Oklahoma and Texas.

(3) Our financial position and cash flow data include the effect of the following public limited partner unit issuances:

Date of Unit Issuance	Class of Limited Partnership Interest	Number of Units Issued	Net Proceeds Including General Partner Contribution
			(in millions)
December 2013	Class A	2,775,000	$ 47.0
November 2013	Class A	18,500,000	$304.5

- The 2013 equity issuances represent the Offering.

(4) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% that was retained by EEP through June 30, 2014. On July 1, 2014, we acquired an additional 12.6% interest in Midcoast Operating from EEP, decreasing EEP's total ownership in Midcoast Operating to 48.4%.

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

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 8. *Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

Items Affecting the Comparability of Our Financial Results

Our future results of operations may not be comparable to our Predecessor's historical results of operations for the reasons described below:

- Our Predecessor's results of operations historically reflected 100% of the revenues and expenses relating to Midcoast Operating. For the first six months of 2014, we owned a 39% controlling interest in Midcoast Operating. On July 1, 2014, we acquired an additional 12.6% ownership interest in Midcoast Operating from EEP for $350.0 million, which reduced the amounts we attribute to noncontrolling interest in our consolidated financial statements. After July 1, 2014, we owned a 51.6% controlling interest in Midcoast Operating. We consolidate the results of operations of Midcoast Operating and then record a 48.4% noncontrolling interest deduction for EEP's retained interest in Midcoast Operating.
- Although the allocation methodology under which we will continue to reimburse EEP and its affiliates for the provisions of certain administrative and operational services to Midcoast Operating will not change, $25.0 million in annual amounts payable for general and administrative expenses that were paid by Midcoast Operating historically under its services agreements is not payable by Midcoast Operating subsequent to the Offering. As a result, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would be fully allocable to Midcoast Operating by $25.0 million annually. As a result, for the year ended December 31, 2014, we recognized $25.0 million as a reduction to "Due to general partner and affiliates" with the offset to "Noncontrolling interest" in our consolidated statements of financial position.
- We incurred an additional $4.0 million of incremental annual general and administrative expenses as a result of being a separate publicly traded partnership, 100% of which is attributable to us.
- EEP no longer provides letters of credit and parental guarantees in support of Midcoast Operating at no cost, and we are responsible for our proportionate share of the annual expenses attributable to a financial support agreement that Midcoast Operating entered into with EEP. During the term of the financial support agreement, when requested by Midcoast Operating, EEP will provide letters of credit and guarantees in support of Midcoast Operating's financial obligations under certain hedges and key

customer natural gas and NGL purchase agreements. Based on the cumulative average amount of letters of credit and guarantees that EEP provided on Midcoast Operating's behalf multiplied by a 2.5% annual fee, Midcoast Operating incurred $2.9 million of these costs for the year ended December 31, 2014, and we expect these costs to be less than $3.0 million going forward. Without such financial support from EEP, we expect that Midcoast Operating would be required to provide letters of credit, cash collateral or other financial support with respect to these agreements or similar agreements it enters into in the future. For more information regarding our financial support agreement and the calculation of this annual fee, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 10. *Debt*.

- We incur interest expense under our borrowing arrangements. Before we acquired control of our Predecessor, it was a wholly owned subsidiary of EEP and, as such, did not incur any direct interest expense from third parties and only recognized intercompany interest expense to the extent such amounts were capitalized as part of its construction projects.

RESULTS OF OPERATIONS—OVERVIEW

We are a growth-oriented Delaware limited partnership formed by EEP to serve as EEP's primary vehicle for owning and growing its natural gas and NGL midstream business in the United States. Midcoast Operating is a Texas limited partnership that owns a network of natural gas and NGL gathering and transportation systems, natural gas processing and treating facilities and NGL fractionation facilities primarily located in Texas and Oklahoma. Midcoast Operating also owns and operates natural gas, condensate and NGL logistics and marketing assets that primarily support its gathering, processing and transportation business. Through our ownership of Midcoast Operating's general partner, we control, manage and operate these systems.

Our business primarily consists of gathering unprocessed and untreated natural gas from wellhead locations and other receipt points on our systems, processing the natural gas to remove NGLs and impurities at our processing and treating facilities and transporting the processed natural gas and NGLs to and through our intrastate and interstate pipelines for transportation to various customers and market outlets. In addition, we also market natural gas and NGLs to wholesale customers.

Our financial condition and results of operations are subject to variability from multiple factors, including:

- the volumes of natural gas, NGLs, condensate, and crude oil that we gather, process and transport on our systems;
- the price of natural gas, NGLs, condensate, and crude oil that we pay for and receive in connection with the services we provide;
- our ability to replace or renew existing contracts, such as our ability to replace a significant processing contract on our Anadarko system that terminated during the third quarter of 2013; and
- the supply and demand for natural gas, NGLs, condensate, and crude oil.

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing. We have established these reporting segments as strategic business units to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31, 2014, 2013 and 2012.

	December 31,		
	2014	2013	2012
	(in millions)		
Operating income (loss)			
Gathering, processing and transportation	$114.9	$70.2	$191.5
Logistics and marketing	43.5	(5.1)	(19.9)
Corporate, operating and administrative	(5.7)	—	(0.2)
Total operating income	152.7	65.1	171.4
Interest expense	16.7	1.7	—
Other income (loss)	12.9	(1.2)	(0.1)
Income tax expense	4.6	8.3	3.8
Net income	$144.3	$53.9	$167.5
Less: Predecessor income prior to initial public offering (from January 1, 2013 through November 12, 2013)		$56.3	
Net loss subsequent to initial public offering attributable to Midcoast Energy Partners, L.P. (from November 13, 2013 through December 31, 2013)		(2.4)	
Less: Net income (loss) attributable to noncontrolling interest	80.2	(0.6)	
Net income (loss) attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ 64.1	$ (1.8)	

Summary Analysis of Operating Results

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. Revenues for our gathering, processing and transportation business are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported and sold through our systems; the volumes of NGLs sold; and the level of natural gas, NGL and condensate prices. The segment gross margin of our gathering, processing and transportation business, which we define as revenue generated from gathering, processing and transportation operations less the cost of natural gas and natural gas liquids purchased, is derived from the compensation we receive from customers in the form of fees or commodities we receive for providing our services, in addition to the proceeds we receive for the sales of natural gas, NGLs and condensate to affiliates and third parties.

The operating income of our Gathering, Processing and Transportation segment for the year ended December 31, 2014, increased $44.7 million, as compared with the same period in 2013, primarily due to changes in segment gross margin. Operating income is largely derived from segment gross margin, which is operating revenues less cost of natural gas and natural gas liquids. Segment gross margin variances are as follows:

- Segment gross margin increased $122.6 million due to non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment, when compared to the same period in 2013;
- Segment gross margin increased $5.8 million due to increased margins from higher commodity prices, net of hedges, related to contracts pursuant to which we are paid in commodities for our services.

- Segment gross margin increased $2.3 million due to improved pricing spreads between the Conway and Mont Belvieu market hubs;
- Segment gross margin decreased approximately $45.8 million primarily due to reduced natural gas and NGL average daily volumes on our major systems primarily attributable to the loss of a major customer on our Anadarko system in 2013 and reduced and delayed drilling activity in the Anadarko and East Texas regions;
- Segment gross margin decreased $33.4 million due to reduced keep-whole processing earnings;
- Segment gross margin decreased approximately $3.0 million primarily due to the impact of sustained freezing temperatures in the first quarter of 2014, which significantly disrupted producer wellhead production levels and our pipeline operations;
- Operating and maintenance costs decreased $2.7 million due primarily to decreased outside contract labor, lower rents and leases, and lower pipeline integrity costs offset by a non-cash asset impairment charge and an increase in costs due to separation costs associated with workforce reductions; and
- Depreciation and amortization expense increased $6.3 million due to additional assets that were placed into service.

Logistics and Marketing

The primary role of our Logistics and Marketing business is to market natural gas, NGLs and condensate received from our Gathering, Processing and Transportation business. We purchase and receive natural gas, NGLs and other products from pipeline systems and processing plants and sell and deliver them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants. Our Logistics and Marketing segment derives a majority of its operating income from selling natural gas and NGLs received from producers on our Gathering, Processing and Transportation segment pipeline assets to customers utilizing the natural gas. A majority of the natural gas and NGLs we purchase are produced in Texas markets where we have expanded access to several interstate natural gas pipelines over the past several years. We can use those interstate pipelines to transport natural gas and NGLs to primary markets where we can sell them to major customers.

Additionally, our Logistics and Marketing segment derives operating income from providing logistics services for our customers from the wellhead to markets. We use owned and leased trucks and specialized trailers and railcars to transport products such as NGLs, condensate and other liquid hydrocarbons to market. In some instances, our margin per unit of volume sold can be higher if the commodity being marketed requires specialized handling, treating, stabilization or other services.

We also derive operating income from the relative difference in natural gas and NGL prices between the contracted index at which the natural gas and NGLs are purchased and the index price at which they are sold, otherwise known as the “basis spread,” which can vary over time or by location, as well as due to local supply and demand factors. Natural gas and NGLs purchased and sold by our logistics and marketing business is primarily priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. We enter into long-term, fixed-price purchase or sales contracts with our customers and generally will enter into offsetting hedge positions under the same or similar terms.

Generally, the demand for natural gas and NGLs is higher during the winter months as these commodities are used to meet residential and commercial heating requirements. In some areas during the summer months, demand for natural gas is higher as utility companies that use natural gas for power generation increase their electricity output to meet residential and commercial demand for air conditioning. Seasonal anomalies such as mild winters or hot summers can lessen or intensify these fluctuations.

The operating income of our Logistics and Marketing segment increased $48.6 million as compared with the year ended December 31, 2013 due to the following:

- Segment gross margin increased due to non-cash, mark-to-market net gains of $38.8 million primarily from the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs and crude oil forward contracts;
- Segment gross margin increased $9.8 million due to increased margins from pricing differentials in the first quarter of 2014. Higher operating income was predominantly due to strong natural gas marketing optimization results attributable to seasonal demand for natural gas deliveries from Mid-Continent to the Midwest market. We benefited from the natural gas pricing difference between market centers in the Mid-Continent supply areas and market area in the Midwest, which arose from higher than normal demand from winter weather in the Midwest;
- Operating and administrative expenses decreased $7.7 million due partly to lower volumes received from our Gathering, Processing and Transportation segment and partly due to a strategic reduction of long hauls due to closer delivery points; and
- Depreciation and amortization increased $2.2 million due to additional assets that were placed into service.

Derivative Transactions and Hedging Activities

Contractual arrangements in our Gathering, Processing and Transportation segment and our Logistics and Marketing segment expose us to market risks associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices, which can be significant during periods of price volatility. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as “Operating revenue” and “Cost of natural gas and natural gas liquids”.

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net changes in fair value associated with our derivative financial instruments:

	December 31,		
	2014	2013	2012
	(in millions)		
Gathering, Processing and Transportation segment			
Hedge ineffectiveness	$ 5.6	$ 3.3	$ 3.1
Non-qualified hedges	123.6	3.3	0.6
Logistics and Marketing segment			
Non-qualified hedges	29.2	(9.6)	(2.5)
Derivative fair value net gains (losses)	$158.4	$(3.0)	$ 1.2

RESULTS OF OPERATIONS — BY SEGMENT

Gathering, Processing and Transportation

Our Gathering, Processing and Transportation segment consists of natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. Our gathering, processing and transportation business consists of the following four systems:

- *Anadarko system:* Approximately 3,100 miles of natural gas gathering and transportation pipelines, approximately 60 miles of NGL pipelines, seven active natural gas processing plants, five standby natural gas processing plants and one standby treating plant located in the Anadarko basin.
- *East Texas system:* Approximately 4,100 miles of natural gas gathering and transportation pipelines, approximately 144 miles of NGL pipelines, four active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, seven active natural gas treating plants, two standby natural gas treating plants and one fractionation facility located in the East Texas basin.
- *North Texas system:* Approximately 3,900 miles of natural gas gathering and transportation pipelines, approximately 29 miles of NGL pipelines, and seven active natural gas processing plants located in the Fort Worth basin.
- *Texas Express NGL system:* A 35% interest in an approximately 593-mile NGL intrastate transportation mainline and a related NGL gathering system that consists of approximately 116 miles of gathering lines. The Texas Express NGL system commenced startup operations during the fourth quarter of 2013.

In addition we have, an approximately 40-mile non-core propylene pipeline extending from Exxon's refinery in Chalmette, Louisiana to an interconnecting Chevron pipeline near Lafitte, Louisiana.

The following tables set forth the operating results of our Gathering, Processing and Transportation segment and the approximate average daily volumes of natural gas throughput and NGLs produced on our major systems for the years ended December 31, 2014, 2013, and 2012.

	December 31,		
	2014	2013	2012
		(in millions)	
Operating revenues	$ 647.3	$ 729.0	$ 818.0
Cost of natural gas and natural gas liquids	27.1	157.6	131.2
Segment gross margin	620.2	571.4	686.8
Operating and maintenance	276.2	278.9	281.5
General and administrative	87.1	86.6	85.8
Depreciation and amortization	142.0	135.7	128.0
Operating expenses	505.3	501.2	495.3
Operating income	$ 114.9	$ 70.2	$ 191.5
Operating Statistics (MMBtu/d)			
East Texas	1,030,000	1,153,000	1,266,000
Anadarko	827,000	949,000	1,017,000
North Texas	293,000	317,000	330,000
Total	2,150,000	2,419,000	2,613,000
NGL Production (Bpd)	83,675	88,236	97,428

Year ended December 31, 2014, compared with year ended December 31, 2013

The operating income of our Gathering, Processing and Transportation segment for the year ended December 31, 2014, increased $44.7 million, as compared with the year ended December 31, 2013. The most significant area affected was segment gross margin, which increased $48.8 million for the year ended December 31, 2014, as compared with the year ended December 31, 2013.

Segment gross margin increased $122.6 million for the year ended December 31, 2014, when compared to the year ended December 31, 2013 primarily related to non-cash, mark-to-market gains in the year ended December 31, 2014, on our NGL and condensate hedges. The values of these hedges and contracts which help assure the prices we realize on commodities increased as the related physical commodity value decreased.

Segment gross margin increased $5.8 million for the year ended December 31, 2014, as compared with the year ended December 31, 2013, due to increased margins from higher commodity prices, net of hedges, related to contracts where we paid in commodities for our services.

Segment gross margin increased $2.3 million for the year ended December 31, 2014, due to improved pricing spreads between our Conway and Mont Belvieu market hubs when compared with the year ended December 31, 2013.

Segment gross margin was affected by reduced production volumes which negatively affected segment gross margin by approximately $45.8 million for the year ended December 31, 2014, compared to the year ended December 31, 2013. The average daily volumes of our major systems for the year ended December 31, 2014, decreased by approximately 269,000 million British Thermal units per day, or MMBtu/d, or 11% when compared to the year ended December 31, 2013. The average NGL production for the year ended December 31, 2014, decreased by 4,561 Bpd, or 5%, when compared to the year ended December 31, 2013. The decrease in natural gas and NGL volumes in the Anadarko region was primarily attributable to the loss in 2013 of a major customer on our Anadarko system and reduced and delayed drilling activity by certain producers. The decrease in natural gas volumes in the East Texas region was primarily attributable to reduced dry gas drilling, and delayed drilling activity and well completions.

Segment gross margin derived from keep-whole earnings for the year ended December 31, 2014, decreased $33.4 million when compared to the year ended December 31, 2013, due to a decrease in processing margins primarily driven by lower volumes in keep-whole barrels in the Oklahoma, East Texas and Anadarko regions.

Segment gross margin decreased approximately $3.0 million for the year ended December 31, 2014, primarily due to the impact of sustained freezing temperatures in the first quarter of 2014, which significantly disrupted producer wellhead production levels and our pipeline operations compared to the year ended December 31, 2013.

Operating and maintenance costs decreased $2.7 million for the year ended December 31, 2014, when compared to the year ended December 31, 2013 primarily related to reduced outside contract labor, and lower rents and leases. This decrease was offset by an increase in costs from a non-cash impairment on our non-core Louisiana propylene pipeline asset of $15.6 million. The impairment charge was taken following finalization of a contract restructuring with the primary customer. In addition, in December of 2014, the company took actions to reduce its costs through a workforce reduction, which increased severance costs by $4.3 million for the year ended December 31, 2014, as compared with the year ended December 31, 2013.

Depreciation and amortization expense for our Gathering, Processing and Transportation segment increased $6.3 million, for the year ended December 31, 2014, compared with the year ended December 31, 2013 due to additional assets that were placed into service.

We recognized $13.2 million in equity income in "Other income (expense)" on our consolidated statements of income related to our investment in the Texas Express NGL system. This is due to a full year of operations of the pipeline which went into service in November 2013.

Year ended December 31, 2013, compared with year ended December 31, 2012

The operating income of our Gathering, Processing and Transportation segment for the year ended December 31, 2013, decreased $121.3 million, as compared with the year ended December 31, 2012. The most significant area affected was segment gross margin, which decreased $115.4 million for the year ended December 31, 2013, as compared with the year ended December 31, 2012.

Reduced production volumes negatively affected segment gross margin by approximately $26.0 million for the year ended 2013. The average daily volumes of our major systems for the year ended 2013, decreased by approximately 194,000 MMBtu/d, or 7%, when compared to the year ended 2012. The average NGL production for the year ended 2013, decreased by approximately 9,192 Bpd, or 9%, when compared to the year ended 2012. The decline in volumes is due to reduced drilling activity in our dry gas operating areas, predominately in East Texas, along with a recent trend of dry gas wells that have been drilled but not completed, and the loss of a major customer contract on our Anadarko system, which led to reduced volumes on the system in the second half of 2013. Additionally, extreme weather conditions for the year ended 2013, as compared to 2012, also contributed to the reduced volumes. During 2013, two different sustained freezing events negatively impacted volume flows on our Anadarko, Elk City, and North Texas systems for a seven to ten day time period. Additionally, a localized fire at our Elk City plant took this asset offline on December 6, 2013, and was expected to be back to full capacity in early 2014. Recent shifts in supply and demand fundamentals for NGLs, particularly ethane, have resulted in downward pressure on the current and forward prices for this commodity. As a result of the lower prices for ethane during the year ended 2013, it was more profitable to operate most of the processing, plant son our Anadarko system in ethane rejection mode, which results in lower NGL volumes, since ethane is sold as part of the natural gas stream.

The segment gross margin for our Gathering, Processing and Transportation segment was negatively affected by the reduction in segment gross margin derived from purchasing some of our NGLs at the Conway market hub and selling them at the Mont Belvieu market hub. On our Anadarko system, we purchase certain NGL components at Conway hub prices and then have the option to resell those same NGL components at Mont Belvieu hub prices. The segment gross margin of our Gathering, Processing and Transportation segment decreased by approximately $57.0 million for the year ended December 31, 2013, when compared with the year ended December 31, 2012, due to reduced pricing spreads between our Conway and Mont Belvieu market hubs.

A variable element of the operating results of our Gathering, Processing and Transportation segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to the barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the year ended December 31, 2013, decreased $27.1 million from the year ended December 31, 2012. The decline in keep-whole earnings is the result of a decline in total NGL production.

Also contributing to the decrease in segment gross margin for the year ended December 31, 2013, was a decrease of approximately $4.0 million due to changes in physical measurement adjustments for the year ended December 31, 2013, as compared to the year ended December 31, 2012. Physical measurement adjustments routinely occur on our systems as part of our normal operations, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational conditions.

Operating and maintenance costs of our Gathering, Processing and Transportation segment decreased $2.6 million for the year ended December 31, 2013, when compared to the year ended December 31, 2012, primarily due to a $4.3 million write down in 2012 of surplus materials associated with deferred portions of a development project on our East Texas system that we do not expect to complete until production levels reach a sustainable level to support our expansion activities in the region. There were no similar costs recorded during the year ended December 31, 2013.

Depreciation expense for our Gathering, Processing and Transportation segment increased $7.7 million for the year ended December 31, 2013, compared with the year ended December 31, 2012, due to additional assets that were put in service during 2012 and 2013.

Future Prospects for Gathering, Processing and Transportation

Our strategy is to expand our natural gas gathering and processing services by (1) capturing opportunities within our footprint, (2) expanding outside of our footprint through strategic acquisitions, (3) providing an array of services for both natural gas and NGLs in combination with core asset optimization, and (4) capitalizing on new market opportunities by diversifying geographically and by commodity composition. We will pursue internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value.

Impact of Commodity Prices

Demand for our gathering, processing and transportation services primarily depends upon the supply of natural gas reserves and associated natural gas from crude oil development and the drilling rate for new wells. Demand for these services depends on overall economic conditions and commodity prices. Commodity prices for natural gas, NGLs, condensate, and crude oil began declining during the fourth quarter of 2014 and into 2015. As a result, there has been recent reduction in drilling activity from producers. We have largely mitigated our direct commodity risk through our hedging program. We have hedged over 80% and over 65% of our direct commodity exposure in 2015 and 2016, respectively. Despite our hedging program, we still bear indirect commodity price impacts as lower drilling activity impacts the volumes on our systems. We expect this indirect impact on our volumes to improve as prices improve.

We have completed several expansion projects and are currently constructing the following major expansion projects that are designed to increase natural gas processing, NGL production, residue gas and NGL transportation capacity.

Beckville Cryogenic Processing Plant

In April 2013, we announced plans to construct a cryogenic natural gas processing plant near Beckville in Panola County, Texas, which we refer to as the Beckville Processing Plant. This plant is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation, which is comprised of approximately ten counties in East Texas and has been a steady producer of natural gas for decades, as well as the Eaglebine developments. Production from the Cotton Valley formation typically contains two to three gallons of NGLs per Mcf of natural gas. The region currently produces approximately 2.2 billion cubic feet per day, or Bcf/d, of natural gas with 73,000 Bpd of associated NGLs. Until recently, the primary exploitation method in the Cotton Valley formation has been vertical wells. Lower horizontal drilling costs, coupled with the latest fracturing technology, has brought significant interest back to this area. Economics associated with horizontal wells in the Cotton Valley formation compare favorably to other rich natural gas plays, which has encouraged producers to increase drilling activity in the region. We expect our Beckville processing plant to be capable of processing approximately 150 MMcf/d of natural gas and producing approximately 8,500 Bpd of NGLs to accommodate the additional liquids-rich natural gas being developed within this geographical area in which our East Texas system operates. Related NGL takeaway infrastructure connecting the Beckville plant to third party NGL transportation systems was also constructed. We estimate the cost of constructing the plant to be approximately $145.0 million and expect it to be placed into commercial service early in the second quarter of 2015.

The project is funded by us and EEP based on our proportionate ownership percentages in Midcoast Operating, which was 39% and 61%, respectively, between November 13, 2013 and June 30, 2014 and 51.6% and 48.4%, respectively, after July 1, 2014.

Eaglebine Developments

The Eaglebine is an emerging oil play in East Texas that spans over five counties and is comprised of multiple formations, including but not limited to, the Woodbine and Eagle Ford formations. We have a series of projects and an acquisition in this play. We have commenced construction of a lateral and associated facilities that will create gathering capacity of over 50 MMcf/d for rich natural gas to be delivered from Eaglebine production areas to our complex of cryogenic processing facilities in East Texas. Given the proximity of our existing East Texas assets, this expansion into Eaglebine will allow us to offer gathering and processing services while leveraging assets on our existing footprint.

On February 9, 2015, we announced an agreement with New Gulf Resources, LLC, or NGR, to purchase NGR's midstream business in Leon, Madison and Grimes Counties, Texas. The acquisition consists of a natural gas gathering system that is currently in operation moving equity and third party production.

We estimate the cost of these projects and acquisitions described above to be approximately $160.0 million, of which $135.0 million is estimated to be spent in 2015. Funding is to be provided by us and EEP based on our proportionate ownership percentages in Midcoast Operating, which are 51.6% and 48.4%, respectively.

Logistics and Marketing

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business, thereby enhancing our competitive position. In addition, our logistics and marketing services provide our customers with the opportunity to receive enhanced economics by providing access to premium markets through the transportation capacity and other assets we control. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from pipeline systems and processing plants and sells and delivers them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants.

The physical assets of our logistics and marketing business primarily consist of:

- Approximately 225 transport trucks, 370 trailers and 190 railcars for transporting NGLs;
- Our TexPan liquids railcar facility near Pampa, Texas;
- An approximately 40-mile crude oil pipeline and associated crude oil storage facility near Mayersville, Mississippi, including a crude oil barge loading facility located on the Mississippi River; and

We also enter into agreements with various third parties to obtain natural gas and NGL supply, transportation, gas balancing, fractionation and storage capacity in support of the logistics and marketing services we provide to our gathering, processing and transportation business and to third-party customers. These agreements provide our logistics and marketing business with the following:

- Up to approximately 79,000 Bpd of firm NGL fractionation capacity;
- Approximately 3.5 Bcf of firm natural gas storage capacity;
- Approximately 0.75 Bcf of interruptible natural gas storage capacity;
- Up to approximately 30,000 Bpd in 2014 to 120,000 Bpd in 2022 of firm NGL transportation capacity on the Texas Express NGL system;
- Up to approximately 89,000 Bpd of additional NGL transportation capacity, a significant portion of which is firm capacity, through transportation and exchange agreements with three NGL pipeline transportation companies; and
- Approximately 6.0 MMBbls of firm NGL storage capacity.

The following table sets forth the operating results of our Logistics and Marketing segment for the years ended December 31, 2014, 2013, and 2012:

	December 31,		
	2014	2013	2012
		(in millions)	
Operating revenues	$5,247.0	$4,864.6	$4,539.9
Cost of natural gas and natural gas liquids	5,118.8	4,779.5	4,452.9
Segment gross margin	128.2	85.1	87.0
Operating and maintenance	62.9	71.4	80.8
General and administrative	12.4	11.6	19.1
Depreciation and amortization	9.4	7.2	7.0
Operating expenses	84.7	90.2	106.9
Operating income (loss)	$ 43.5	$ (5.1)	$ (19.9)

Our logistics and marketing business derives a majority of its segment gross margin, which we define as revenue generated from the sale of natural gas, NGLs and condensate less the cost of natural gas and natural gas liquids purchased, from purchasing and receiving natural gas, NGLs and other products.

Year ended December 31, 2014, compared with year ended December 31, 2013

The operating income of our Logistics and Marketing segment for the year ended December 31, 2014, increased $48.6 million, as compared with the year ended December 31, 2013. The most significant area affected was segment gross margin, which increased $43.1 million for the year ended December 31, 2014, as compared with the year ended December 31, 2013.

Segment gross margin experienced an increase in non-cash, mark-to-market net gains of $38.8 million for the year ended December 31, 2014, compared to the year ended December 31, 2013 primarily from gains due to the NGL forward contracts and the non-qualifying commodity derivatives we use to economically hedge a portion of the NGLs resulting from the operating activities of our Logistics and Marketing segment, compared to losses in the year ended December 31, 2013.

Segment gross margin increased $9.8 million for the year ended December 31, 2014, as compared with the year ended December 31, 2013 due to increased margins from natural gas pricing differentials in the first quarter of 2014. We benefited from the difference between market centers in the Mid-Continent supply areas and market area in the Midwest, which arose from higher than normal demand from winter weather in the Midwest.

Operating and administrative costs decreased $7.7 million for the year ended December 31, 2014, as compared with the year ended December 31, 2013, due partly to lower volumes received from our Gathering, Processing and Transportation segment and partly due to a strategic reduction of long hauls due to closer delivery points. Included in these amounts was $0.5 million in separation costs associated with workforce reductions.

Depreciation and amortization expense for the year ended December 31, 2014, increased $2.2 million for year ended December 31, 2014, as compared with the year ended December 31, 2013, due to additional assets that were placed into service.

Year ended December 31, 2013, compared with year ended December 31, 2012

The operating income of our Logistics and Marketing segment for the year ended December 31, 2013, increased $14.8 million, as compared with the same period in 2012. Segment gross margin decreased $1.9 million for the year ended December 31, 2013, as compared with the year ended December 31, 2012.

Segment gross margin experienced non-cash, mark-to-market net losses of $7.1 million from December 31, 2012, to December 31, 2013, mostly due to changes in the average forward prices of natural gas, NGLs and condensate. The average forward and daily prices for natural gas and propane increased for the year ended December 31, 2013, compared to the year ended December 31, 2012. We use the non-qualifying commodity derivatives to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our logistics and marketing business.

Segment gross margin was also negatively impacted by modestly lower storage margins resulting from the sale of liquids product inventory at prevailing market prices relative to the cost of the product inventory in storage. Contributing to segment gross margin was the expiration of certain transportation fees for natural gas being transported on a third party pipeline. These fees expired, effective June 30, 2012, and reduced natural gas expense by approximately $2.0 million for the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Segment gross margin for the current year was also affected by only $3.4 million of non-cash charges to inventory for the year ended December 31, 2013, as compared with $9.8 million loss for the year ended December 31, 2012, which we recorded to reduce the cost basis of our natural gas inventory to net realizable value. Since we hedge our storage positions financially, these charges are recovered when the physical natural gas inventory is sold or the financial hedges are realized.

Operating and maintenance costs of our Logistics and Marketing segment were $9.4 million lower for the year ended December 31, 2013, compared with the year ended December 31, 2012, due to reduced outside contract labor costs and lower maintenance activities on existing trucks and trailers resulting from a more updated fleet.

General and administrative costs of our Logistics and Marketing segment decreased $7.5 million for the year ended December 31, 2013, compared to the year ended December 31, 2012, due to costs we incurred in 2012 for the investigation of accounting irregularities at our trucking and NGL marketing subsidiary.

Depreciation and amortization expense was relatively flat for the year ended December 31, 2013, when compared with the year ended December 31, 2012.

Corporate Activities

Our corporate activities consist of interest expense, interest income and other costs such as income taxes, which are not allocated to our business segments.

	December 31,		
	2014	2013	2012
	(in millions)		
Operating and maintenance	$ 0.4	$—	$—
General and administrative	5.3	—	0.2
Operating expenses	5.7	—	0.2
Operating loss	(5.7)	—	(0.2)
Interest expense, net	16.7	1.7	—
Other income (expense)	—	0.3	(0.1)
Income tax expense	4.6	8.3	3.8
Net loss	(27.0)	(9.7)	(4.1)
Net income (loss) attributable to noncontrolling interest	80.2	(0.6)	—
Net loss attributable to general and limited partners	$(107.2)	$(9.1)	$(4.1)

Year ended December 31, 2014, compared with year ended December 31, 2013

General and administrative expenses increased $5.3 million for the year ended December 31, 2014, as compared to the year ended December 31, 2013 due to increased professional fees and costs incurred since the Offering. Additionally, there was a full year of administrative expenses in 2014 when compared to costs in 2013 that were incurred only after our initial public offering on November 13, 2013.

Interest expense increased $15.0 million for the year ended December 31, 2014, as compared to the year ended December 31, 2013 due to a full year of borrowings in 2014 on our Credit Agreement. Additionally, we had interest expense on our $400.0 million in notes issued in a private offering which was completed on September 30, 2014.

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income are typically borne by our unitholders through the allocation of taxable income.

The state tax structure that exists in Texas imposes taxes that are based upon many, but not all, items included in net income. Income tax expense decreased $3.7 million primarily due to a tax law that was passed in June 2013 in the State of Texas, referred to as the House Bill 500, or HB 500. The law allows a pipeline company that transports oil, gas, or other petroleum products owned by others to subtract as cost of goods sold, its depreciation, operations and maintenance costs related to the services provided. Under this law, we are allowed additional deductions against its income for Texas margin tax purposes. As a result, a one-time increase to deferred income tax expense of $6.0 million was recorded in 2013 and we incurred lower income tax expense in 2014.

Year ended December 31, 2013, compared with year ended December 31, 2012

Interest expense increased $1.7 million for the year ended December 31, 2013, as compared to the year ended December 31, 2012, due to outstanding debt acquired since our initial public offering on November 13, 2013.

The tax structure that exists in Texas imposes taxes that are based upon many, but not all, items included in net income. Our income tax expense of $8.3 million for the year ended 2013, is computed by applying a 0.5% Texas state income tax rate to modified gross margin, as defined by Texas state income tax laws, and $6.0 million related to a one-time increase to deferred income tax expense. For 2012, we had an income tax expense of $3.8 million, which we computed by applying a 0.5% Texas state income tax rate to modified gross margin.

LIQUIDITY AND CAPITAL RESOURCES

General

Historically, our sources of liquidity included cash generated from operations and funding from EEP. While not obligated to do so, EEP continues to fund its proportionate share of growth capital projects. In 2014 EEP provided approximately $154.3 million to fund its share of capital expenditures.

In addition, at the close of the Offering, Midcoast Operating entered into a Financial Support Agreement, which we refer to as the Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP will, from time to time, provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party. For further details regarding the Financial Support Agreement, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 10. *Debt*.

We were dependent upon EEP and its affiliates for our treasury services. We now have separate bank accounts from EEP, but EEP provides treasury services on our General Partner's behalf under an intercorporate services agreement that we entered into with EEP at the closing of the Offering. Under the intercorporate services agreement, EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would be fully allocable to Midcoast Operating by $25.0 million annually.

We expect our ongoing sources of liquidity to include cash generated from operations of Midcoast Operating, borrowings under our senior revolving credit facility, which we refer to as the Credit Agreement, and issuances of additional debt and equity securities. We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements and long-term capital expenditure requirements and to make quarterly cash distributions to our unitholders.

On July 1, 2014, we acquired an additional 12.6% limited partner interest in Midcoast Operating from EEP for $350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction represents our first acquisition of additional interests in Midcoast Operating since the Offering. We do not know when, or if, any additional interests will be offered to us to purchase. As a result of our increased ownership interest in Midcoast Operating, we will have increased funding requirements for capital projects in periods subsequent to the drop down transaction.

We intend to pursue acquisitions of additional interests in our natural gas assets held through Midcoast Operating from EEP. EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time, although EEP is not legally obligated to do so. We do not know when, or if, any additional interest will be offered to us to purchase. Additionally, although EEP has the option to fund its pro rata share of Midcoast Operating's capital expenditures, to the extent it elects not to do so, we may elect to fund EEP's portion in exchange for additional interests in Midcoast Operating and, as a result, our interest in Midcoast Operating would increase over time.

Available Liquidity

Our primary source of liquidity is provided by the Credit Agreement. As set forth in the following table, at December 31, 2014, we had $490.0 million of liquidity available to us to meet our ongoing operational, investment and financing needs.

	(in millions)
Cash and cash equivalents	$ —
Total credit available under Credit Agreement	$ 850.0
Amounts outstanding under Credit Agreement	(360.0)
Total	$ 490.0

The amounts we may borrow under the terms of our Credit Agreement are reduced by the face amount of our letters of credit outstanding.

Equity and Debt Financing Activities

Private Debt Issuance

On September 30, 2014, we completed a private placement of $400.0 million of debt securities pursuant to a Note Purchase Agreement, or the Purchase Agreement, between the Partnership and the purchasers named therein. The debt consists of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. The Notes and all other obligations under the Purchase Agreement are unconditionally guaranteed on a senior basis by each of the domestic material subsidiaries of the Partnership pursuant to a guaranty agreement. All of the five Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. We received approximately $398.1 million in net proceeds, which were used to repay outstanding indebtedness and for other general partnership purposes. Using a portion of the net proceeds, we settled two interest rate swaps for a net payment of $0.9 million on September 30, 2014, which will be amortized to interest expense over the original five year hedge term. At December 31, 2014, we were in compliance with the terms of our financial covenants under the Purchase Agreement. For further details related to the Purchase Agreement and the related private placement, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 10. *Debt.*

Credit Agreement

On November 13, 2013, we, Midcoast Operating, and our material domestic subsidiaries, entered into the Credit Agreement by and among us, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, our material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially: (1) $90.0 million under the letter of credit facility; and (2) $75.0 million under the swing line facility. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility initially matured on November 13, 2016, subject to four one-year requests for extensions.

On September 30, 2014, we amended our Credit Agreement to extend the maturity date from November 13, 2016, to September 30, 2017; however, $140.0 million of commitments will expire on the original maturity date of November 13, 2016. At December 31, 2014, we had $360.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 3.2%. Under the Credit Agreement, we had net borrowings of approximately $25.0 million during the year ended December 31, 2014, which includes gross borrowings of $6,920.0 million and gross repayments of $6,895.0 million. At December 31, 2014, we were in compliance with the terms of our financial covenants in the Credit Agreement. For further details regarding the Credit Agreement and the amendments thereto, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 10. *Debt*.

Working Capital Credit Facility

On November 13, 2013, Midcoast Operating entered into a $250.0 million working capital credit facility with EEP as the lender. On October 30, 2014, Midcoast Operating exercised its right to terminate the working capital credit facility, effective November 30, 2014. At the time of the termination, there were no outstanding borrowings under this facility. For further details regarding the working capital credit facility, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 10. *Debt*.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. To that end, in December 2014, we filed a shelf registration statement on Form S-3 with the Securities and Exchange Commission with a proposed aggregate offering price for all securities registered of $1.5 billion, which became effective on February 5, 2015.

Sale of Accounts Receivable

We and certain of our subsidiaries are parties to a receivables purchase arrangement pursuant to a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013 and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. The Receivables Agreement terminates on December 30, 2016. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of participating sellers, consisting of certain of our subsidiaries and certain EEP subsidiaries up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected.

For the year ended December 31, 2014 we sold and derecognized $3,484.0 million of receivables that indirect wholly-owned subsidiary of Enbridge, and we received cash proceeds of $3,483.1 million. As of December 31, 2014, $272.7 million of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

As of December 31, 2014, we have $17.7 million included in “Restricted cash” on our consolidated statements of financial position, consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary. For further details regarding the Receivable Agreement, refer to Item 8. *Financial Statements and Supplementary Data*, under Note 12. *Related Party Transactions*.

Cash Requirements

Capital Spending

In 2015, we plan to spend approximately $180.0 million on expansion capital and other projects associated with our natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. We made capital expenditures of $236.0 million for the year ended December 31, 2014, including $57.7 million on maintenance capital activities and excluding $25.2 million in net contributions to fund our joint ventures. At December 31, 2014, we had approximately $53.7 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2015. In addition, at December 31, 2014, we also had approximately $3.0 million in outstanding purchase commitments attributable to commodity purchases.

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under the Credit Facility and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

In addition, EEP has indicated that it intends to offer us the opportunity to purchase additional interests in Midcoast Operating from time to time. These acquisitions sometimes referred to as “drop-down” transactions, will provide an alternative source of funding for EEP while at the same time providing an opportunity for meaningful growth in our cash flows. However, EEP is under no obligation to offer to sell us additional interests in Midcoast Operating, and we are under no obligation to buy any such additional interests. On July 1, 2014, we acquired an additional 12.6% limited partner interest in Midcoast Operating from EEP for $350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. We believe that we will be well-positioned to acquire additional interests in Midcoast Operating if the opportunity arises.

Under the amended and restated agreement of limited partnership of Midcoast Operating that we and EEP entered into in November 2013, we and EEP each have the option to contribute our proportionate share of additional capital to Midcoast Operating if any additional capital contributions are necessary to fund expansion capital expenditures or other growth projects. To the extent that we or EEP elect not to make any such capital contributions, the contributing party will be permitted to make additional capital contributions to Midcoast Operating to the extent necessary to fully fund such expenditures in exchange for additional ownership interests in Midcoast Operating.

Forecasted Expenditures

We categorize our capital expenditures as either maintenance or expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which are worn, obsolete or completing its useful life, in each case over the long term. Examples of maintenance capital expenditures include expenditures to replace pipelines or processing facilities, to maintain equipment reliability, integrity and safety or to comply with existing governmental regulations and industry standards. We also include in maintenance capital expenditures a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems. Expenditure levels will increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that maintenance capital expenditures will increase due to the growth of our pipeline systems. We expect to fund our proportional share of maintenance capital expenditures through operating cash flows.

Expansion capital expenditures are those expenditures incurred for acquisitions or capital improvements that we expect will increase our asset base, operating capacity or operating income over the long term or meaningfully extend the useful life of any of our capital assets. Examples of expansion capital expenditures include the acquisition of additional assets or businesses, as well as capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase operating capacities or revenues from existing levels, reduce operating costs from existing levels or enable us to respond to new governmental regulations and developing industry standards. We anticipate funding our proportional share of expansion capital expenditures temporarily through borrowings under our revolving credit facility, with long-term debt and equity funding being obtained when needed and as market conditions allow.

If EEP elects not to fund any capital expenditures at Midcoast Operating, we will have the option to fund all or a portion of EEP's proportionate share of such capital expenditures in exchange for additional interests in Midcoast Operating. As a result, if our interests in Midcoast Operating increase, our proportionate share of the capital expenditures incurred by Midcoast Operating will also increase proportionate to our interest in Midcoast Operating. To the extent that EEP elects not to fund all or a portion of its proportionate share of Midcoast Operating's capital expenditures, and we elect not to fund any capital expenditures not funded by EEP, we expect that Midcoast Operating will not pursue the applicable capital projects associated with such unfunded capital expenditures.

The following table sets forth our estimated maintenance, expansion capital expenditures and acquisition opportunities we expect to incur in 2015. Although we anticipate making these expenditures in 2015, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. For the full year ending December 31, 2015, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
Beckville Cryogenic Processing Plant	$ 50
Eaglebine Developments	135
Compression Capital	20
Wellconnect Expansion Capital	40
Expansion Capital	45
Maintenance Capital Expenditure Activities	55
	345
Less: Joint Funding from:	
EEP[1]	165
	$180

[1] Joint funding is based upon EEP's current 48.4% ownership of Midcoast Operating.

Distributions

Our partnership agreement requires that we distribute all of our available cash quarterly. This requirement forms the basis of our cash distribution policy and reflects a basic judgment that our unitholders will be better served by distributing our available cash rather than retaining it, because, among other reasons, we believe we will generally finance any expansion capital expenditures from external financing sources. For the year ended December 31, 2014, our annual cash distribution rate was $1.37 per unit. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions in this or any other amount, and our General Partner has considerable discretion to determine the amount of our available cash each quarter. In addition, our General Partner may change our cash distribution policy at any time, subject to the requirement in our partnership agreement to distribute all of our available cash quarterly. Generally, our available cash is our (1) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (2) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we expect to have more cash to distribute than would be the case if we were subject to federal income tax. If we do not generate sufficient available cash from our operations, we may, but are under no obligation to, borrow funds to pay the minimum quarterly distribution to our unitholders.

Our partnership agreement provides that, during the subordination period, the Class A common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.3125 per Class A common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the Class A common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the Class A common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution on the Class A common units from prior quarters. Furthermore, no arrearages will accrue or be payable on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that, during the subordination period, there will be available cash to be distributed on the Class A common units.

The subordination period began upon the closing of the Offering and will extend until the first business day following the distribution of available cash in respect of any quarter beginning after December 31, 2016 that each of the following tests are met:

- Distributions of available cash from operating surplus on each of the outstanding Class A common units, subordinated units and general partner units equaled or exceeded $1.25 per unit (the annualized minimum quarterly distribution), for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- The adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of $1.25 per unit (the annualized minimum quarterly distribution) on all of the outstanding Class A common units, subordinated units and general partner units during those periods on a fully diluted basis; and
- There are no arrearages in payment of the minimum quarterly distribution on the Class A common units.

Notwithstanding the foregoing, the subordination period will automatically terminate on the first business day following the distribution of available cash in respect of any quarter, beginning with the quarter ended December 31, 2014, that each of the following tests are met:

- Distributions of available cash from operating surplus on each of the outstanding Class A common units, subordinated units and general partner units equaled or exceeded $1.875 per unit (150% of the annualized minimum quarterly distribution), plus the related distributions on the incentive distribution rights, for the four-quarter period immediately preceding that date;
- The adjusted operating surplus generated during the four-quarter period immediately preceding that date equaled or exceeded the sum of (1) $1.875 per unit (150% of the annualized minimum quarterly distribution) on all of the outstanding Class A common units, subordinated units and general partner units during that period on a fully diluted basis and (2) the corresponding distributions on the incentive distribution rights; and
- There are no arrearages in payment of the minimum quarterly distributions on the Class A common units.

When the subordination period ends, the outstanding subordinated units will convert into Class B common units, and all Class A common units will no longer be entitled to arrearages. The Class B common units will be convertible at the option of the holder into Class A common units at any time that our General Partner determines, based on the advice of counsel, that the Class B common units to be converted have like intrinsic economic and federal income tax characteristics to Class A common units.

Derivative Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at December 31, 2014 for each of the indicated calendar years:

	Notional	2015	2016	2017	2018	2019	Total[3][4]
			(in millions)				
Swaps							
Natural gas[1]	84,992,590	$ 2.8	$ 0.1	$—	$—	$—	$ 2.9
NGL[2]	3,395,200	32.4	9.3	0.7	—	—	42.4
Crude Oil[2]	3,353,550	15.0	1.0	0.8	—	—	16.8
Options							
Natural gas—puts purchased[1]	5,662,000	3.8	1.0	—	—	—	4.8
Natural gas—calls written[1]	2,924,500	—	(0.1)	—	—	—	(0.1)
NGL—puts purchased[2]	5,456,000	40.2	39.3	1.2	—	—	80.7
NGL—calls written[2]	4,634,750	(0.6)	(3.2)	(0.7)	—	—	(4.5)
Crude Oil—puts purchased[2]	1,900,200	18.8	14.7	4.1	—	—	37.6
Crude Oil—calls written[2]	1,900,200	(0.4)	(2.7)	(3.3)	—	—	(6.4)
Natural gas—puts written[1]	5,662,000	(3.8)	(1.0)				(4.8)
Natural gas—call purchased[1]	2,924,500	—	0.1				0.1
Forward contracts							
Natural gas[1]	199,855,804	1.2	0.3	0.1	—	—	1.6
NGL[2]	8,472,814	18.9	—	—	—	—	18.9
Crude Oil[2]	634,853	(0.9)	—	—	—	—	(0.9)
Totals		$127.4	$58.8	$ 2.9	$—	$—	$189.1

(1) Notional amounts for natural gas are recorded in Millions of British thermal units, or MMBtu.
(2) Notional amounts for NGL and crude oil are recorded in Barrels, or Bbl.
(3) Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $1.1 million of loss at December 31, 2014.
(4) Excludes $28.4 million of cash collateral at December 31, 2014.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2014:

	2015	2016	2017	2018	2019	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$ 53.7	$ —	$ —	$ —	$ —	$ —	$ 53.7
Other operating leases	22.5	21.6	20.7	14.2	14.1	341.3	434.4
Right-of-way	0.7	0.5	0.2	0.2	—	0.5	2.1
Product purchase obligations[2]	14.8	8.3	14.7	24.5	25.5	112.5	200.3
Transportation/Service contract obligations[3]	63.3	58.3	99.5	109.1	113.8	403.5	847.5
Fractionation agreement obligations[4]	70.1	70.1	70.1	70.1	70.1	235.0	585.5
Total	$225.1	$158.8	$205.2	$218.1	$223.5	$1,092.8	$2,123.5

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our growth projects.
(2) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at the approximate market value at the time of delivery.
(3) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.
(4) The fractionation agreement obligations represent the minimum payment amounts for firm fractionation of our NGL supply that we reserve at third party fractionation facilities.

The payments made under our obligations and commitments for the years ended December 31, 2014, 2013 and 2012 were $1.7 billion, $334.4 million and $117.0 million, respectively.

Cash Flow Analysis

The following table summarizes the changes in cash flows by operating, investing and financing for each of the years indicated:

	For the year ended December 31,		
	2014	2013	2012
		(in millions)	
Total cash provided by (used in):			
Operating activities	$ 159.1	$ 420.9	$ 352.7
Investing activities	(231.3)	(522.3)	(614.5)
Financing activities	67.3	106.3	261.8
Net increase in cash and cash equivalents	(4.9)	4.9	—
Cash and cash equivalents at beginning of year	4.9	—	—
Cash and cash equivalents at end of period	$ —	$ 4.9	$ —

Changes in our working capital accounts are shown in the following table and discussed below:

	For the year ended December 31,		
	2014	2013	2012
		(in millions)	
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 33.2	$ 7.9	$ 67.8
Due from General Partner and affiliates	608.6	(633.9)	4.5
Accrued receivables	(47.4)	295.6	(68.2)
Inventory	(4.9)	(12.2)	12.0
Current and long-term other assets	(23.9)	(14.3)	(4.5)
Due to General Partner and affiliates	(468.2)	522.8	17.9
Accounts payable and other	(21.2)	34.6	2.1
Accrued purchases	(90.5)	4.9	6.4
Interest payable	4.7	0.3	—
Property and other taxes payable	1.1	3.4	—
Net change in working capital accounts	$ (8.5)	$ 209.1	$ 38.0

Year ended December 31, 2014 compared with year ended December 31, 2013

Operating Activities

Net cash provided by our operating activities decreased $261.8 million for the twelve month period ended December 31, 2014 compared to the year ended December 31, 2013, primarily due to (1) a $146.8 million decrease in non-cash adjustments, and (2) a $217.6 million decrease in the change to our working capital accounts offset by increased distributions of $12.2 million from our joint ventures and a $90.4 million increase in net income.

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the year ended December 31, 2014, compared with the year ended December 31, 2013, is primarily the result of general timing differences for cash receipts and payments associated with our current and related party accounts. Other items affecting our cash flows from operating assets and liabilities include the following:

- The changes in the balances Due to and Due from General Partner and affiliates are primarily attributable to transition of cash management functions from EEP to us following the Offering and into early 2014. EEP provided us with interim cash management services following the Offering to facilitate the collection of and payment on our accounts, which resulted in an increase in amounts receivable from and payable to EEP as of December 31, 2013. During the first quarter of 2014, we completed this transition and settled most of the transactions causing a decrease in both our Due to and Due from General Partner and affiliates account. These transactions were not present during the remainder of 2014;
- Decreased cash flows from changes in the balances of accrued receivables are primarily the result of having sold $335.9 million of our accrued receivables outstanding as of December 31, 2012 to an Enbridge subsidiary under a purchase agreement, or the Receivables Agreement, that we entered into on June 28, 2013. The Receivables Agreement was in place throughout all of 2014;
- Decreased cash flows from changes in accrued purchases are primarily the result of lower levels of accrued purchases at December 31, 2014, which stem from lower volumes purchased at lower prices as compared to the prior year; and
- Decreased cash flows from changes in accounts payable and other from December 31, 2013 to December 31, 2014 was primarily the result of paying a book overdraft that was present at December 31, 2013 that was not present at December 31, 2014, coupled with decreased operating accruals related to our transportation business.

The decrease in non-cash items primarily consisted of increased derivative net gains of $161.4 million, primarily as a result of fluctuations in commodity prices, partially offset by an asset impairment charge of $15.6 million on our propylene line.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2014 decreased by $291.0 million, compared to the year ended December 31, 2013, primarily due to:

- Decreased contributions to fund the construction activities associated with the Texas Express NGL system of approximately $151.9 million since the system went into service in late 2013, coupled with $27.8 million in distributions in excess of cumulative earnings from our joint venture investment in the Texas Express NGL system received during the year ended December 31, 2014;
- Decreased restricted cash balance of $80.2 million consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary in accordance with the Receivables Agreement; and
- Decreased additions to property, plant and equipment, net of construction payables, of $35.7 million when compared with 2013, due to many of our capital projects being put into service in 2013 with less capital projects projected for the future.

Financing Activities

Net cash provided by our financing activities decreased $39.0 million for the year ended December 31, 2014, compared to the year ended December 31, 2013, primarily due to:

- Decreased distribution to EEP for assets contributed from the Offering and initial credit facility borrowings of $674.8 million;

- Increased proceeds of $398.1 million from the issuance of debt through the private placement of three series of senior notes partially offset by decreased net borrowings of $310.0 million for amounts previously outstanding under our credit facility in 2014;
- Decreased net proceeds from the Offering of $354.9 million for which we had no similar transactions during 2014;
- Decreased distributions and contributions to Predecessor partner interests of $247.7 million and $341.9 million, respectively, from the year ended December 31, 2013. These 2013 transactions were offset by a payment of $350.0 million to EEP for our acquisition of a portion of its noncontrolling interest in Midcoast Operating in 2014;
- Increased contributions from noncontrolling interest and partners of $142.8 million, coupled with increased distributions to noncontrolling interest of $95.9 million; and
- Increased distributions to partners of $52.7 million for year ended December 31, 2014.

Year ended December 31, 2013 compared with year ended December 31, 2012

Operating Activities

Net cash provided by our operating activities increased $68.2 million for the twelve month period ended December 31, 2013 compared to the year ended December 31, 2012, primarily due to an increase in our working capital accounts of $171.1 million. This increase due to our working capital accounts was partially offset by a $113.6 million decrease in net income, offset by other non-cash items.

The changes in our operating assets and liabilities, net of acquisitions as presented in our consolidated statements of cash flow for the year ended December 31, 2013, compared with the year ended December 31, 2012, is primarily the result of general timing differences for cash receipts and payments associated with our current and related party accounts. Other items affecting our cash flows from operating assets and liabilities include the following:

- The change in accrued receivables was favorable due to the sale of $335.9 million to a subsidiary of Enbridge pursuant to the Receivables Agreement. Similar sales of accrued receives did not occur in 2012, since 2013 is the first year the Receivables Agreement was active. For more information, refer to the discussion above *Sale of Accounts Receivable;*
- The changes in the balances of due to and due from General Partner and affiliates are primarily attributable to transition of cash management functions from EEP to MEP following the Offering. EEP provided us with interim cash management services following the Offering to facilitate the collection of and payment on our accounts, which resulted in increase in amounts receivable from and payable to EEP; and
- The change in trade receivables was unfavorable due to unfavorable pricing spreads of $57.0 million between hubs at Conway and Mount Belvieu. In 2012, we had the opportunity to benefit from purchasing natural gas at Conway and selling it at a higher price at Mount Belvieu. In 2013, the price differential reversed, thus we did not purchase and sell as much natural gas between these two hubs.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2013 increased by $92.2 million, compared to the year ended December 31, 2012, primarily due to:

- Increased restricted cash balance of $61.5 million consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary in accordance with the Receivables Agreement. For more information, refer to Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—*Liquidity and Capital Resources "Sale of Accounts Receivable"*; and

- Increased contributions to fund the construction activities associated with the Texas Express NGL system of approximately $20.1 million.

Offsetting the increase in investing activities discussed above was $178.3 million fewer additions to property, plant and equipment, net of construction payables, for the year ended December 31, 2013 when compared with 2012 as many of our capital projects were put into service in 2013 with less capital projects projected for the future.

Financing Activities

Net cash provided by our financing activities decreased $155.5 million for the year ended December 31, 2013, compared to the year ended December 31, 2012, primarily due to the following:

- Increased net proceeds from our initial public offering in November 2013 of $354.9 million; and
- Increased borrowings, net of repayments, under our Credit Facility of $335.0 million.

Offsetting the increase in financing activities discussed above were:

- Distributions to EEP of proceeds from the initial public offering in November 2013 and credit facility borrowings of $674.8 million; and
- Decreased capital contributions from our General Partner and its affiliates, net of distributions to our General Partner and its affiliates of $167.6 million in 2013.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Eaglebine Acquisition

On February 9, 2015, we announced an agreement with New Gulf Resources, LLC, or NGR, to purchase NGR's midstream business in Leon, Madison and Grimes Counties, Texas for $85.0 million. The acquisition consists of a natural gas gathering system that is currently in operation moving equity and third party production.

Distribution to Partners

On January 28, 2015, the board of directors of our General Partner, declared a cash distribution payable to our partners on February 13, 2015. The distribution was paid to unitholders of record as of February 6, 2015, of our available cash of $15.8 million at December 31, 2014, or $0.3425 per limited partner unit. We paid $7.3 million to the holders of our public Class A common units, while $8.5 million in the aggregate was paid to EEP with respect to its Class A common units, subordinated units and general partner interest.

Midcoast Operating Distribution

On January 28, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of February 6, 2015. Midcoast Operating paid $21.1 million to us and $19.8 million to EEP on February 13, 2015.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Discontinued Operations

In April 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2014-08 that changes the criteria and requires expanded disclosures for reporting discontinued operations. This accounting update is effective for annual and interim periods beginning after December 15, 2014, and is to be applied prospectively. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

Revenues from Contracts with Customers

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 that outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements.

Going Concern Uncertainties

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of an entity's ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity's ability to continue as a going concern. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016, with early adoption permitted. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our selection and application of accounting policies is an important process that has developed as our business activities have evolved and as new accounting pronouncements have been issued. Accounting decisions generally involve an interpretation of existing accounting principles and the use of judgment in applying those principles to the specific circumstances existing in our business. We believe the proper implementation and consistent application of all applicable accounting principles is critical. However, not all situations we encounter are specifically addressed in the accounting literature. In such cases, we must use our best judgment to implement accounting policies that clearly and accurately present the substance of these situations. We accomplish this by analyzing similar situations and the accounting guidance governing them and consulting with experts about the appropriate interpretation and application of the accounting literature to these situations.

In addition to the above, certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures with respect to contingent assets and liabilities. The basis for our estimates is historical experience, consultation with experts and other sources we believe to be reliable. While we believe our estimates are appropriate, actual results can and often do differ from these estimates. Any effect on our business, financial position, results of operations and cash flows resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

We believe our critical accounting policies and estimates discussed in the following paragraphs address the more significant judgments and estimates we use in the preparation of our consolidated financial statements. Each of these areas involve complex situations and a high degree of judgment either in the application and interpretation of existing accounting literature or in the development of estimates that affect our consolidated financial statements. Our management has discussed the development and selection of the critical accounting policies and estimates related to the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent liabilities with the Audit, Finance & Risk Committee of Enbridge Management's board of directors.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas and Natural Gas Liquids

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectability is reasonably assured. For our gathering, processing and transportation and logistics and marketing businesses, we must estimate our current month revenue and cost of natural gas and NGLs to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas and NGLs based on the best available volume and price data for natural gas and NGLs delivered and received, along with an adjustment of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas and NGLs for each period reported. We believe that the assumptions underlying these estimates will not be significantly different from the actual amounts due to the routine nature of these estimates and the consistency of our processes.

Within our gathering, processing and transportation business, we receive fee-based revenue for services, such as compression fees, gathering fees and treating fees, which are recognized when the services are performed. Additionally, revenues of our gathering, processing and transportation business that are derived from transmission services consist of reservation fees charged for transportation of natural gas and NGLs on some of our intrastate pipeline systems. Customers paying these fees sometimes pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transportation volumes. Reservation fees are required to be paid whether or not the shipper delivers the volumes, thus referred to as a ship-or-pay arrangement. Consequently, we recognize revenue for reservation fees ratably over the period in which capacity is reserved. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas, NGLs and transportation services.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for: (1) assets purchased or constructed; (2) existing assets that are replaced, improved or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of its estimated useful life or the estimated remaining lives of the natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we recognize a gain or loss in our consolidated statements of income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of income.

Assessment of Recoverability of Goodwill

Goodwill represents the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. At December 31, 2014, the carrying amount of goodwill was $226.5 million consisting of $206.1 million and $20.4 million related to our gathering, processing, and transportation and logistics and marketing reporting units, respectively. We test goodwill for impairment annually based on carrying values of our reporting units as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may be impaired. Impairment occurs when the carrying amount of a reporting unit's goodwill exceeds its implied fair value. We reduce the carrying value of goodwill to its fair value at the time we determine that impairment has occurred.

We do not perform a qualitative assessment of impairment for either of our reporting units. In connection with our quantitative assessments, we primarily use a discounted cash flow analysis to determine the fair values of our reporting units. In addition, we also consider overall market capitalization of our business, cash flow measurement data and other factors. We make critical assumptions that include but are not limited to: (1) projections of future financial performance, which include commodity price and volume assumptions, (2) the expected growth rate of our assets, (3) residual values of the assets; and (4) market weighted average cost of capital.

The critical assumptions used in our analysis as of June 30, 2014 included the following:

1) A weighted average cost of capital of approximately 7.5%;

2) A terminal growth rate for our gathering, processing and transportation and logistics and marketing businesses of approximately 5.0% and 1.0%, respectively;

3) A capital structure consisting of approximately 40% debt and 60% equity; and

4) A long-term commodity price forecast using recent pricing information.

Based on the results of our annual goodwill impairment testing, no indicators of impairment were noted, and the fair values of our reporting units were in excess of their carrying values. We have not observed any further events or circumstances subsequent to our analysis that would, more likely than not, reduce the fair value of our reporting units below the carrying amounts as of December 31, 2014. We continue to monitor the impacts of changes in commodity prices and other economic factors on our assumptions.

We believe the assumptions used in our analyses are appropriate and result in reasonable estimates of the fair values of our reporting units. However, the assumptions used are subject to uncertainty, and declines in the future performance or cash flows of our reporting units, decreases to our terminal growth rate assumptions due to changing business conditions, such as commodity prices and drilling, or increases to our weighted average cost of capital assumptions due to changes in credit or equity markets may result in the recognition of impairment charges, which could be significant.

Assessment of Recoverability of Intangible Assets

Our intangible assets primarily consist of customer contracts for the purchase and sale of natural gas, natural gas supply opportunities and contributions we have made in aid of construction activities that will benefit our operations, as well as workforce contracts and customer relationships. We amortize these assets on a straight-line basis over the weighted average useful lives of the underlying assets, representing the period over which the assets are expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our intangible assets whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangible assets, we compare the carrying value to the undiscounted future cash flows we expect the intangible assets or the underlying assets to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangible assets, we write the intangible assets down to their fair value.

Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value to our derivative instruments and disclosures associated with our outstanding commodity activities. We define fair value as the expected price we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We employ a hierarchy which prioritizes the inputs we use to measure recurring fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.
- Level 2—We include in this category the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument. This category includes both over-the-counter, or OTC, transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted prices for assets and liabilities; (b) time value; (c) volatility factors; and

(d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources (i.e., values supported by lesser volumes of market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 assets and liabilities primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. Additionally, Level 3 valuations may utilize modeled pricing inputs to derive forward valuations, which may include some or all of the following inputs: non-binding broker quotes, time value, volatility, correlation and extrapolation methods.

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust on a recurring basis each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply a mid-market pricing convention, which we refer to as the market approach, to value substantially all of our derivative instruments.

Our assets are adjusted for the non-performance risk of our counterparties using their current credit default swap spread rates. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and is also adjusted using a credit adjustment model incorporating inputs such as credit default swap rates, bond spreads, and default probabilities.

Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations. Actively traded external market quotes, data from pricing services and published indices are also used to value our derivative instruments. We may use these inputs along with internally developed methodologies that result in our best estimates of fair value.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows as they relate to inventories, firm commitments and certain anticipated transactions.

We record all derivative financial instruments at fair market value in our Consolidated Statements of Financial Position. Price assumptions we use to value our non-qualifying derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. We may also use these inputs with internally developed methodologies that result in the best estimate of fair value. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Effective January 1, 2014, we elected to prospectively change the presentation of derivative assets and liabilities from a net basis to a gross basis in the Consolidated Statements of Financial Position. We adopted this change to provide more detailed information about the future economic benefits and obligations associated with our derivative activities in our Consolidated Statements of Financial Position. This change had no impact to the Consolidated Statements of Income, Net income (loss) per limited partner unit, or Partners' capital.

Qualified Hedges

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in "Accumulated other comprehensive income," also referred to as AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement until the underlying transaction occurs. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in "Cost of natural gas and natural gas liquids" for commodity hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two month period of time thereafter.

Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by the board of directors of Midcoast Holdings or a committee of senior management appointed by our General Partner. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

At inception, we formally document the relationship between the hedging instrument and the hedged item, the risk management objective, and the method used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, we regularly assess the creditworthiness of our counterparties to manage against the risk of default. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have derivative financial instruments associated with our commodity activities where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value included in "Cost of natural gas and natural gas liquids" or "Operating revenue" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

In all instances related to the commodity exposures, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical cost or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Commitments and Contingencies

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as such costs are incurred.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

COMMODITY PRICE RISK

Our exposure to commodity price risk exists within our Gathering, Processing and Transportation and Logistics and Marketing segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

	At December 31, 2014						At December 31, 2013	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	896,915	$ 2.94	$ 3.67	$ —	$ (0.7)	$ —	$ —
	NGL	225,850	$35.24	$65.37	$ —	$ (6.8)	$ —	$ —
	Crude Oil	912,250	$56.73	$86.82	$ —	$(27.4)	$ —	$ —
Receive fixed/pay variable	Natural Gas	3,645,440	$ 3.95	$ 2.93	$ 3.7	$ —	$ —	$ —
	NGL	1,980,850	$46.91	$27.11	$39.2	$ —	$ 1.5	$ (1.1)
	Crude Oil	1,244,400	$90.83	$56.74	$42.4	$ —	$ 1.7	$ —
Receive variable/pay variable	Natural Gas	59,606,800	$ 2.89	$ 2.89	$ 1.5	$ (1.7)	$ 0.1	$ —
Physical Contracts								
Receive variable/pay fixed	Natural Gas	232,400	$ 3.09	$ 2.99	$ —	$ —	$ —	$ —
	NGL	206,300	$22.54	$39.95	$ —	$ (3.6)	$ —	$ —
	Crude Oil	11,300	$53.44	$56.27	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	290,114	$ 3.02	$ 3.18	$ —	$ —	$ —	$ —
	NGL	1,042,921	44.60	25.58	19.8	—	$ —	$ —
	Crude Oil	65,000	$62.46	$54.00	$ 0.5	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	148,689,068	$ 2.95	$ 2.95	$ 2.2	$ (1.0)	$ 0.5	$ (0.1)
	NGL	7,221,805	$22.68	$22.30	$ 3.7	$ (1.0)	$ —	$ —
	Crude Oil	558,553	$50.57	$53.07	$ 0.3	$ (1.7)	$ —	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	181,435	$ 3.15	$ 3.85	$ —	$ (0.1)	$ —	$ —
	Crude Oil	415,950	$62.96	$82.69	$ —	$ (8.1)	$ —	$ —
Receive fixed/pay variable	Natural Gas	75,000	$ 3.48	$ 3.52	$ —	$ —	$ —	$ —
	NGL	823,500	$39.64	$28.18	$ 9.3	$ —	$ —	$ —
	Crude Oil	415,950	$85.08	$62.96	$ 9.1	$ —	$ 0.7	$ —
Receive variable/pay variable	Natural Gas	20,587,000	$ 3.30	$ 3.29	$ 0.5	$ (0.3)	$ —	$ —
Physical Contracts								
Receive fixed/pay variable	NGL	1,788	$28.67	$25.71	$ —	$ —	$ —	$ —
Receive variable/pay variable	Natural Gas	34,834,479	$ 3.40	$ 3.39	$ 0.7	$ (0.4)	$ 0.1	$ —
Portion of contracts maturing in 2017								
Swaps								
Receive fixed/pay variable	NGL	365,000	$24.78	$22.79	$ 0.7	$ —	$ —	$ —
	Crude Oil	365,000	$69.35	$66.97	$ 0.8	$ —		
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,909,743	$ 3.77	$ 3.76	$ 0.2	$ (0.1)	$ —	$ —
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	900,000	$ 4.03	$ 4.03	$ —	$ —	$ —	$ —

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.4 million of losses at December 31, 2014 and $0.1 million of gains at December 31, 2013 and collateral received.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2014 and 2013.

	At December 31, 2014						At December 31, 2013	
					Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Strike Price[2]	Market Price[2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 3.03	$ 3.8	$—	$ 1.7	$—
	NGL	2,254,500	$43.41	$26.09	$40.2	$—	$ 6.0	$—
	Crude Oil	730,000	$81.56	$56.78	$18.8	—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 3.03	$ —	$—	$—	$(0.3)
	NGL	1,433,250	$45.74	$25.97	$ —	$(0.6)	$—	$(1.0)
	Crude Oil	730,000	$88.39	$56.78	$ —	$(0.4)	$—	$(1.9)
Puts (written)	Natural Gas	4,015,000	$ 3.90	$ 3.02	$ —	$(3.8)	$—	$—
Calls (purchased)	Natural Gas	1,277,500	$ 5.05	$ 3.03	$ —	$—	$—	$—
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 3.46	$ 1.0	$—	$—	$—
	NGL	2,836,500	$39.24	$27.03	$39.3	$—	$—	$—
	Crude Oil	805,200	$75.91	$63.21	$14.7	$—	$—	$—
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 3.46	$ —	$(0.1)	$—	$—
	NGL	2,836,500	$45.14	$27.03	$ —	$(3.2)	$—	$—
	Crude Oil	805,200	$86.68	$63.34	$ —	$(2.7)	$—	$—
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 3.46	$ —	$(1.0)	$—	$—
Calls (purchased)	Natural Gas	1,647,000	$ 4.98	$ 3.46	$ 0.1	$—	$—	$—
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	365,000	$23.10	$22.79	$ 1.2	$—	$—	$—
	Crude Oil	365,000	$66.00	$66.97	$ 4.1	$—	$—	$—
Calls (written)	NGL	365,000	$26.15	$22.79	$ —	$(0.7)	$—	$—
	Crude Oil	365,000	$74.00	$66.97	$ —	$(3.3)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2014 and 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.7 million of losses at December 31, 2014 and cash collateral received.

QUALITATIVE FACTORS

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31,	
	2014	2013
	(in millions)	
Other current assets	$164.7	$ 10.3
Other assets, net	91.5	10.3
Accounts payable and other[1]	(74.4)	(21.1)
Other long-term liabilities	(22.5)	(0.9)
Due from General Partner and affiliates	0.3	—
	$159.6	$ (1.4)

(1) Includes $28.4 million of cash collateral at December 31, 2014.

The changes in the assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	December 31,	
	2014	2013
	(in millions)	
Counterparty Credit Quality[1]		
AAA	$ 0.1	$ 0.2
AA[2]	74.4	(2.1)
A	67.1	(1.1)
Lower than A	18.0	1.6
	$159.6	$(1.4)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $28.4 million of cash collateral at December 31, 2014.

As the net value of our derivative financial instruments has increased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also increased. When credit thresholds are met pursuant to the terms of our ISDA® financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. As of December 31, 2014, we are holding cash collateral of $28.4 million on our asset exposures and none as of December 31, 2013. Cash collateral is classified as “Restricted cash” in our consolidated statements of financial position. When we are in a position of posting collateral to cover our counterparties’ exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At December 31, 2014 and 2013, we had credit concentrations in the following industry sectors, as presented below:

	December 31, 2014	December 31, 2013
	(in millions)	
United States financial institutions and investment banking entities[1]	$ 88.5	$ 2.4
Non-United States financial institutions	30.7	0.1
Integrated oil companies	1.7	(1.6)
Other	38.7	(2.3)
	$159.6	$(1.4)

(1) Includes $28.4 million of cash collateral at December 31, 2014.

Accumulated Other Comprehensive Income

Also included in AOCI are unrecognized losses of approximately $0.1 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the twelve month period ended December 31, 2014 and 2013, unrealized commodity hedge losses of $0.2 million and gains of $1.7 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $26.4 million, representing unrealized net gains from our cash flow hedging activities based on pricing and positions at December 31, 2014, will be reclassified from AOCI to earnings during the next 12 months.

We used a portion of the net proceeds of our September 30, 2014 debt issuance of $400.0 million to settle treasury locks we entered in July 2014 to hedge the interest payments on a portion of these obligations. The $0.9 million settlement amount is being amortized from AOCI to interest expense over the 5 year original hedge term.

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs, and Crude Oil) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2014[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts— Financial							
Natural Gas	$ 0.6	Market Approach	Forward Gas Price	2.55	3.72	3.04	MMBtu
NGLs	$ 42.1	Market Approach	Forward NGL Price	0.48	1.14	0.64	Gal
Commodity Contracts— Physical							
Natural Gas	$ 1.5	Market Approach	Forward Gas Price	1.55	4.08	3.08	MMBtu
Crude Oil	$ (0.9)	Market Approach	Forward Crude Oil Price	49.57	55.60	53.51	Bbl
NGLs	$ 18.9	Market Approach	Forward NGL Price	0.06	1.21	0.54	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$106.7	Option Model	Option Volatility	19%	94%	36%	
Total Fair Value	$168.9						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gallon, or Gal, for NGLs, Bbl for Crude Oil and dollars per Megawatt hour, or MWh, for Power.

(2) Fair values include credit valuation adjustments of approximately $1.0 million of losses.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
	(in millions)						
Commodity Contracts— Financial							
Natural Gas	$—	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	$(6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts— Physical							
Natural Gas	$ 1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	$(0.5)	Market Approach	Forward Crude Oil Price	86.37	103.04	97.24	Bbl
NGLs	$(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Commodity Options							
Natural Gas, Crude and NGLs	$ 8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 2.0						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.

(2) Fair values include credit valuation adjustments of approximately $0.1 million of gains.

Item 8. Financial Statements and Supplementary Data

**INDEX TO CONSOLIDATED FINANCIAL STATEMENTS,
SUPPLEMENTARY INFORMATION AND
CONSOLIDATED FINANCIAL STATEMENT SCHEDULES
MIDCOAST ENERGY PARTNERS, L.P.**

FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this report have been omitted because they are not applicable or the required information is either immaterial or shown in the consolidated financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Partners of Midcoast Energy Partners, L.P.:

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, of comprehensive income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Midcoast Energy Partners, L.P. and its subsidiaries at December 31, 2014 and December 31, 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our audits (which was an integrated audit in 2014). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 17, 2015

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	For the year ended December 31,		
	2014	2013	2012
	(in millions, except per unit amounts)		
Operating revenues:			
Operating revenue (Note 14)	$5,688.2	$5,380.5	$4,961.7
Operating revenue—affiliate (Notes 12 and 14)	206.1	213.1	396.2
	5,894.3	5,593.6	5,357.9
Operating expenses:			
Cost of natural gas and natural gas liquids (Notes 5 and 14)	5,026.7	4,817.5	4,294.6
Cost of natural gas and natural gas liquids—affiliate (Notes 12 and 14)	119.2	119.6	289.5
Operating and maintenance (Notes 6 and 13)	234.8	242.2	252.2
Operating and maintenance—affiliate (Note 12)	104.7	108.1	110.1
General and administrative	8.7	—	7.9
General and administrative—affiliate (Note 12)	96.1	98.2	97.2
Depreciation and amortization (Note 6)	151.4	142.9	135.0
	5,741.6	5,528.5	5,186.5
Operating income	152.7	65.1	171.4
Interest expense, net (Note 10)	16.7	1.7	—
Equity in earnings of joint ventures (Note 9)	13.2	(1.0)	—
Other loss (Note 13)	(0.3)	(0.2)	(0.1)
Income before income tax expense	148.9	62.2	171.3
Income tax expense (Note 15)	4.6	8.3	3.8
Net income	$ 144.3	$ 53.9	$ 167.5
Less: Predecessor income prior to initial public offering (from January 1, 2013 through November 12, 2013)		56.3	
Net loss subsequent to initial public offering to Midcoast Energy Partners, L.P. (from November 13, 2013 through December 31, 2013)		(2.4)	
Less: Net income (loss) attributable to noncontrolling interest	80.2	(0.6)	
Net income (loss) attributable to general and limited partner ownership interest in Midcoast Energy Partners, L.P.	$ 64.1	$ (1.8)	
Net income attributable to limited partner ownership interest	$ 62.8	$ 19.7	$ 64.0
Net income per limited partner unit (basic and diluted) (Note 3)	$ 1.39	$ 0.68	$ 2.40
Weighted average limited partner units outstanding	45.2	29.2	26.7
Cash distributions paid per limited partner unit outstanding	$ 1.14	$ —	$ —

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the year ended December 31,		
	2014	2013	2012
		(in millions)	
Net income	$144.3	$ 53.9	$167.5
Other comprehensive income (loss), net of tax expense (benefit) of $0.2, $(0.1), and $0.2, respectively (Note 14)	30.4	(10.2)	35.8
Comprehensive income	174.7	43.7	203.3
Less: Comprehensive income (loss) attributable to:			
Noncontrolling interest (Note 12)	80.2	(0.6)	—
Other comprehensive income (loss) attributed to noncontrolling interest (Note 12)	15.7	(3.3)	—
Comprehensive income attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 78.8	$ 41.0	$203.3

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the year ended December 31,		
	2014	2013	2012
		(in millions)	
Cash provided by operating activities:			
Net income	$ 144.3	$ 53.9	$ 167.5
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization (Note 6)	151.4	142.9	135.0
Derivative fair value net losses (gains) (Note 14)	(158.4)	3.0	(1.2)
Inventory market price adjustments (Note 5)	11.4	3.4	9.8
Asset impairment charges (Note 6)	15.6	—	—
Distributions from investment in joint ventures	12.2	—	—
Equity loss (earnings) from investment in joint ventures (Note 9)	(13.2)	1.0	—
Deferred income taxes (Note 15)	3.1	7.3	0.1
Other	1.7	0.3	3.5
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	33.2	7.9	67.8
Due from General Partner and affiliates	608.6	(633.9)	4.5
Accrued receivables	(47.4)	295.6	(68.2)
Inventory (Note 5)	(4.9)	(12.2)	12.0
Current and long-term other assets (Note 14)	(23.9)	(14.3)	(4.5)
Due to General Partner and affiliates	(468.2)	522.8	17.9
Accounts payable and other (Notes 4 and 14)	(21.2)	34.6	2.1
Accrued purchases (Note 13)	(90.5)	4.9	6.4
Interest payable	4.7	0.3	—
Property and other taxes payable	1.1	3.4	—
Settlement of interest rate derivatives (Note 14)	(0.5)	—	—
Net cash provided by operating activities	159.1	420.9	352.7
Cash used in investing activities:			
Additions to property, plant and equipment (Notes 6 and 17)	(237.7)	(273.4)	(451.7)
Changes in restricted cash (Note 12)	18.7	(61.5)	—
Asset acquisitions	(0.2)	(0.9)	—
Proceeds from the sale of net assets	—	5.0	9.2
Investment in joint ventures (Note 9)	(36.7)	(188.6)	(168.5)
Distributions from investment in joint ventures in excess of cumulative earnings	27.8	—	—
Other	(3.2)	(2.9)	(3.5)
Net cash used in investing activities	(231.3)	(522.3)	(614.5)
Cash provided by financing activities:			
Proceeds from long-term debt, net of discounts (Note 10)	398.1	—	—
Net borrowings under credit facility (Note 10)	25.0	335.0	—
Debt origination fees (Note 10)	—	(3.0)	—
Net proceeds from unit issuances (Note 11)	—	354.9	—
Acquisition of noncontrolling interest in subsidiary (Note 11)	(350.0)	—	—
Contributions from Predecessor partner interests (Note 11)	—	341.9	564.0
Contribution from noncontrolling interest (Note 11)	142.8	—	—
Distributions to Predecessor partner interests (Note 11)	—	(247.7)	(302.2)
Distributions to partners (Note 11)	(52.7)	—	—
Distributions to noncontrolling interest (Note 11)	(95.9)	—	—
Distribution to EEP for net assets contributed (Notes 11 and 12)	—	(674.8)	—
Net cash provided by financing activities	67.3	106.3	261.8
Net increase in cash and cash equivalents	(4.9)	4.9	—
Cash and cash equivalents at beginning of year	4.9	—	—
Cash and cash equivalents at end of period	$ —	$ 4.9	$ —

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2014	December 31, 2013
	(in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents (Note 4)	$ —	$ 4.9
Restricted cash (Notes 12 and 14)	42.8	61.5
Receivables, trade and other, net of allowance for doubtful accounts of $1.8 in 2014 and $0.5 in 2013	15.6	50.3
Due from General Partner and affiliates (Note 12)	49.7	654.8
Accrued receivables	229.6	182.2
Inventory (Note 5)	81.5	88.0
Other current assets (Note 14)	178.1	19.1
	597.3	1,060.8
Property, plant and equipment, net (Note 6)	4,159.7	4,082.3
Goodwill (Note 7)	226.5	226.5
Intangible assets, net (Note 8)	247.7	255.0
Equity investment in joint ventures (Note 9)	380.6	371.3
Other assets, net (Note 14)	142.3	40.5
	$5,754.1	$6,036.4
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Due to General Partner and affiliates (Note 12)	$ 41.1	$ 534.3
Accounts payable and other (Notes 4, 13 and 14)	113.8	114.4
Accrued purchases	375.2	463.3
Property and other taxes payable (Note 15)	20.9	19.8
Interest payable	5.0	0.3
	556.0	1,132.1
Long-term debt (Note 10)	760.0	335.0
Other long-term liabilities (Notes 13 and 15)	41.5	16.6
	1,357.5	1,483.7
Commitments and contingencies (Note 13)		
Partners' capital (Note 11):		
Class A common units (22,610,056 authorized and issued at December 31, 2014 and 2013)	634.2	495.3
Subordinated units (22,610,056 authorized and issued at December 31, 2014 and 2013)	1,174.0	1,035.1
General Partner units (922,859 authorized and issued at December 31, 2014 and 2013)	47.8	42.2
Accumulated other comprehensive income (loss) (Note 14)	11.6	(3.1)
Total Midcoast Energy Partners, L.P. partners' capital	1,867.6	1,569.5
Noncontrolling interest	2,529.0	2,983.2
Total partners' capital	4,396.6	4,552.7
	$5,754.1	$6,036.4

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS' L.P.
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	For the year ended December 31,					
	2014		2013		2012	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
Class A common units:						
Beginning balance	22,610,056	$ 495.3	—	$ —	—	$ —
Allocation of limited partner interests	—	—	1,335,056	282.4	—	—
Proceeds from IPO	—	—	21,275,000	354.9	—	—
Distributions to partners	—	(25.8)	—	—	—	—
Distributions of proceeds from IPO and credit facility	—	—	—	(141.1)	—	—
Acquisition of noncontrolling interest in subsidiary	—	133.3	—	—	—	—
Net income (loss)	—	31.4	—	(0.9)	—	—
Ending balance	22,610,056	634.2	22,610,056	495.3	—	—
Subordinated units:						
Beginning balance	22,610,056	1,035.1	—	—	—	—
Allocation of limited partner interests	—	—	22,610,056	1,548.8	—	—
Distributions to partners	—	(25.8)	—	—	—	—
Distributions to predecessor partner interests	—	—	—	(512.8)	—	—
Acquisition of noncontrolling interest in subsidiary	—	133.3	—	—	—	—
Net income (loss)	—	31.4	—	(0.9)	—	—
Ending balance	22,610,056	1,174.0	22,610,056	1,035.1	—	—
General Partner:						
Beginning balance	922,859	42.2	—	—	—	—
Allocation of limited partner interests	—	—	922,859	63.1	—	—
Distributions to partners	—	(1.1)	—	—	—	—
Distributions to predecessor partner interests	—	—	—	(20.9)	—	—
Acquisition of noncontrolling interest in subsidiary	—	5.4	—	—	—	—
Net income	—	1.3	—	—	—	—
Ending balance	922,859	47.8	922,859	42.2	—	—
Predecessor Partner Interest:[(1)]						
Beginning balance		—		4,707.1		4,277.8
Net income		—		56.3		167.5
Contributions		—		341.9		564.0
Distributions		—		(247.7)		(302.2)
Allocation of limited partner interests		—		(4,857.6)		—
Ending balance		—		—		4,707.1
Accumulated other comprehensive income:						
Beginning balance		(3.1)		7.1		(28.7)
Changes in fair value of derivative financial instruments reclassified to earnings		1.8		(2.7)		(0.1)
Changes in fair value of derivative financial instruments recognized in other comprehensive income (loss)		12.9		(7.5)		35.9
Ending balance		11.6		(3.1)		7.1
Total Midcoast Energy Partners, L.P. partners' capital at December 31,		1,867.6		1,569.5		4,714.2
Noncontrolling interest:						
Beginning balance		2,983.2		—		—
Allocation of limited partner interests		—		2,963.0		—
Capital contributions		167.8		24.1		—
Acquisition of noncontrolling interest in subsidiary		(622.0)		—		—
Comprehensive income:						
Net income (loss) allocation		80.2		(0.6)		—
Other comprehensive income, net of tax		15.7		(3.3)		—
Distributions to noncontrolling interests		(95.9)		—		—
Ending balance		2,529.0		2,983.2		—
Total partners' capital at December 31,		$4,396.6		$ 4,552.7		$4,714.2

(1) These amounts represent the changes in the capital account for the years ended December 31, 2013, and 2012, of the former limited partner of Midcoast Operating, our predecessor for accounting purposes. These changes are not to the Partnership's limited partner interests, and thus, are shown here separately.

The accompanying notes are an integral part of these consolidated financial statements.

MIDCOAST ENERGY PARTNERS, L.P.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND NATURE OF OPERATIONS

Initial Public Offering

Midcoast Energy Partners, L.P., or MEP, is a publicly-traded Delaware limited partnership formed by Enbridge Energy Partners, L.P., or EEP, to serve as EEP's primary vehicle for owning and growing its natural gas and natural gas liquids midstream business in the United States. Unless the context otherwise requires, references in this report to the Predecessor, we, our, us, or like terms, when used in a historical context (before November 13, 2013), refer to Midcoast Operating, L.P., or Midcoast Operating. References in this report to Midcoast Energy Partners, the Partnership, MEP, we, our, us, or like terms used in the present tense or prospectively (on or after November 13, 2013) refer to Midcoast Energy Partners, L.P. and its subsidiaries.

On November 13, 2013, we completed our initial public offering, or the Offering, of 18,500,000 Class A common units (2,775,000 additional Class A common units were issued pursuant to the exercise of the underwriters' over-allotment option on December 9, 2013), representing limited partner interests. On the same date, in connection with the closing of the Offering, certain transactions, among others, occurred pursuant to which EEP effectively conveyed to us (1) all of its limited liability company interests in Midcoast OLP GP, L.L.C. (the general partner of Midcoast Operating) and (2) a 39% limited partner interest in Midcoast Operating, in exchange for certain Class A common units, subordinated units, a right to receive \$323.4 million in cash, and approximately \$304.5 million in cash as reimbursement for certain capital expenditures with respect to the conveyed businesses. We received proceeds (net of underwriting discounts, structuring fees and offering expenses) from the Offering of approximately \$354.9 million. We used the net proceeds to distribute approximately \$304.5 million to EEP, to pay approximately \$3.4 million in revolving credit facility origination and commitment fees and used approximately \$47.0 million to redeem 2,775,000 Class A common units from EEP.

Following the completion of the Offering, EEP owned a 61% noncontrolling interest in Midcoast Operating. EEP also retained a significant interest in us through its ownership of our General Partner, a 52% limited partner interest after the exercise of the over-allotment option and all of our incentive distribution rights. The Class A common units are traded on the NYSE under the ticker symbol "MEP."

On July 1, 2014, we acquired an additional 12.6% limited partner interest in Midcoast Operating from EEP for \$350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction represents our first acquisition of additional interests in Midcoast Operating from EEP since the Offering.

General

We own and operate a portfolio of assets engaged in the business of gathering, processing and treating natural gas, as well as the transportation and marketing of natural gas, NGLs, crude oil and condensate. Our portfolio of natural gas and NGL pipelines, plants and related facilities are geographically concentrated in the Gulf Coast and Mid-Continent regions of the United States, primarily in Texas and Oklahoma. We also own and operate natural gas and NGL logistics and marketing assets that primarily support our gathering, processing and transportation business. We hold our assets in a series of limited partnerships and limited liability companies that we wholly own, either directly or indirectly.

After filing our Annual Report on Form 10-K for the period ended December 31, 2013, we determined that \$29.4 million in affiliate operating and maintenance expenses were improperly classified as third-party operating and maintenance expenses. We have concluded that this error was immaterial to the prior year consolidated financial statements for the year ended December 31, 2013. This error did not impact our financial position, earnings, or cash flows for the year ended December 31, 2013. We have revised these amounts for the year ended December 31, 2013 in the current consolidated statements of income.

Enbridge Energy Partners, L.P.

EEP was formed in 1991 by Enbridge Energy Company, Inc., its general partner, an indirect, wholly-owned subsidiary of Enbridge Inc., which we refer to as Enbridge, a leading energy transportation and distribution company headquartered in Calgary, Alberta, Canada. EEP was formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership, which owns the United States portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada.

EEP is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets and, through its ownership interests in us, natural gas gathering, treating, processing, transmission and marketing assets in the United States of America. EEP's Class A common units are traded on the New York Stock Exchange, or NYSE, under the symbol "EEP."

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C., which we refer to as Enbridge Management, is a Delaware limited liability company that was formed by Enbridge Energy Company, Inc. in May 2002. EEP's general partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management's listed shares are traded on the NYSE under the symbol "EEQ." Enbridge Management owns all of a special class of EEP's limited partner interests and derives all of its earnings from its investment in EEP.

Enbridge Management's principal activity is managing the business and affairs of EEP pursuant to a delegation of control agreement among EEP's general partner, Enbridge Management and EEP. In accordance with its limited liability company agreement, Enbridge Management's activities are restricted to being a limited partner of EEP and managing its business and affairs.

Enbridge Inc.

Enbridge is the indirect parent of EEP's general partner, and its common shares are publicly traded on the NYSE in the United States and on the TSX in Canada, in each case, under the symbol "ENB." Enbridge is a leader in energy transportation and distribution in North America, with a focus on crude oil and liquids pipelines, natural gas pipelines, natural gas distribution and renewable energy. At December 31, 2014 and 2013, Enbridge and its consolidated subsidiaries held an effective 18.2% and 11.1% interest in MEP, respectively, through its indirect ownership in Enbridge Management and EEP's general partner.

Business Segments

We conduct our business through two distinct reporting segments: Gathering, Processing and Transportation and Logistics and Marketing.

Gathering, Processing and Transportation

Our gathering, processing and transportation business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. We gather natural gas from the wellhead and central receipt points on our systems, deliver it to our facilities for processing and treating and deliver the residue gas to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies. We deliver the NGLs produced at our processing and fractionation facilities to intrastate and interstate pipelines for transportation to the NGL market hubs in Mont Belvieu, Texas and Conway, Kansas.

Our gathering, processing and transportation business primarily consists of our Anadarko system, the East Texas system and the North Texas system, which provide natural gas gathering, processing, transportation and related services predominantly in active producing basins in east and north Texas, as well as the Texas Panhandle and western Oklahoma. At December 31, 2014, our gathering, processing and transportation business included eight active and three standby natural gas treating plants and 18 active and six standby natural gas processing plants, excluding plants that are inactive based on current volumes. In addition, our gathering, processing and transportation business includes approximately 11,100 miles of natural gas gathering and transmission lines and approximately 233 miles of NGL gathering and transportation lines.

On October 31, 2013, Midcoast Energy Partners L.P., Enterprise Product Partners L.P., or Enterprise, Anadarko Petroleum Corporation, or Anadarko, and DCP Midstream Partners, LP, or DCP Midstream, announced the start of service on the Texas Express NGL system, which consists of two separate joint ventures with these third parties that own and operate an NGL pipeline, or mainline, and NGL gathering system. The joint venture ownership of the mainline portion of the Texas Express NGL system is owned 35% by Enterprise, 35% by us, 20% by Anadarko and 10% by DCP Midstream. The joint venture ownership of the new NGL gathering system is owned 45% by Enterprise, 35% by us and 20% by Anadarko. Enterprise constructed and serves as the operator of the mainline, while we constructed and operate the new gathering system.

The Texas Express NGL pipeline originates near Skellytown, Texas in the Texas Panhandle and extends approximately 593 miles to NGL fractionation and storage facilities in the Mont Belvieu area on the Texas Gulf Coast. The mainline has an initial capacity of approximately 280,000 Bpd and is expandable to approximately 400,000 Bpd with additional pump stations on the system. There are currently capacity reservations on the mainline that, when fully phased in, will total approximately 250,000 Bpd.

Logistics and Marketing

The primary role of our logistics and marketing business is to market natural gas, NGLs and condensate received from our gathering, processing and transportation business, thereby enhancing our competitive position. In addition, our logistics and marketing services provide our customers with the opportunity to receive enhanced economics by providing access to premium markets through the transportation capacity and other assets we control. Our logistics and marketing business purchases and receives natural gas, NGLs and other products from pipeline systems and processing plants and sells and delivers them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

We prepare our consolidated financial statements in accordance with U.S. GAAP. Our preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingent assets and liabilities. We regularly evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the circumstances. Nevertheless, actual results may differ significantly from these estimates. We record the effect of any revisions to these estimates in our consolidated financial statements in the period in which the facts that give rise to the revision become known.

Principles of Consolidation

The consolidated financial statements include our accounts and all accounts on a consolidated basis of: (1) our wholly and majority-owned subsidiaries; and (2) our subsidiaries over which we have control, even if we do not have a majority ownership. We consolidate the accounts of entities over which we have a controlling financial interest through our ownership of the general partner or the majority voting interests of the entity. All significant intercompany accounts and transactions have been eliminated in consolidation. Our 35% ownership interests in Texas Express Pipeline, L.L.C. and Texas Express Gathering, L.L.C. are accounted for under the equity method of accounting as a result of our ability to significantly influence the operating activities of these entities, but insufficient ability to control these activities without the participation of a majority of the other members.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas and Natural Gas Liquids

Gathering, Processing and Transportation

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectability is reasonably assured. We derive revenue in our Gathering, Processing and Transportation business from the following types of arrangements:

Fee-Based Arrangements

In a fee-based arrangement, we receive a fee per thousand cubic feet, or Mcf, of natural gas processed or per gallon of NGLs produced. Under this arrangement, we have no direct commodity price exposure. Within our gathering, processing and transportation business, we receive fee-based revenue for services, such as compression fees, gathering fees and treating fees, which are recognized when services are performed. Additionally, revenues of our gathering, processing and transportation business that are derived from transmission services consist of reservation fees charged for transportation of natural gas on some of our intrastate pipeline systems. Customers paying these fees sometimes pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transportation volumes. Reservation fees are required to be paid whether or not the shipper delivers the volumes, thus referred to as a ship-or-pay arrangement. Consequently, we recognize revenue for reservation fees ratably over the period in which capacity is reserved. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transportation services.

Commodity-Based Arrangements

We also generate revenue and segment gross margin under other types of service arrangements with customers. These arrangements expose us to commodity price risk, which we mitigate to a substantial degree with the use of derivative financial instruments to hedge open positions in these commodities. We hedge a significant amount of our exposure to commodity price risk to support the stability of our cash flows.

The commodity-based service contracts we have with customers are categorized as follows:

- *Percentage-of-Proceeds Contracts*—Under these contracts, we receive a negotiated percentage of the sales proceeds related to natural gas and NGLs we process. The processed products include residue natural gas, NGLs, condensate and sulfur, which we can sell at market prices and retain a percentage of the proceeds as our compensation. This type of arrangement exposes us to commodity price risk, as the revenues from percentage-of-proceeds contracts directly correlate with the market prices of the applicable commodities that we receive.
- *Percentage-of-Liquids Contracts*—Under these contracts, we receive a negotiated percentage of the NGLs extracted from natural gas that require processing, which we can then sell at market prices and retain the proceeds as our compensation. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGLs produced. Ownership of the residue natural gas remaining after the extraction of NGLs resides with the customer. This type of contract may also require us to provide the customer with a guaranteed NGL recovery percentage regardless of actual NGL production. Since revenues from percentage-of-liquids contracts directly correlate with the market price of NGLs, this type of arrangement also exposes us to commodity price risk.
- *Percentage-of-Index Contracts*—Under these contracts, we purchase raw natural gas at a negotiated percentage of an agreed upon index price. We then resell the natural gas, generally for the index price, and keep the difference as our compensation.
- *Keep-Whole Contracts*—Under these contracts, we gather or purchase raw natural gas from the customer. We extract and retain the NGLs produced during processing for our own account, which we then sell at market prices. In instances where we purchase raw natural gas at the wellhead, we may also

sell the resulting residue natural gas for our own account at market prices. In those instances when we gather and process raw natural gas for the customer's account, we generally must return to the customer residue natural gas with an energy content equivalent to the original raw natural gas we received, as measured in British thermal units, or Btu. This type of arrangement has the highest commodity price exposure because our costs are dependent on the price of natural gas purchased and our revenues are dependent on the price of NGLs sold. As a result, we benefit from these types of contracts when the value of the NGLs is high relative to the cost of the natural gas and are disadvantaged when the cost of the natural gas is high relative to the value of the NGLs.

Under the terms of each of our commodity-based service contracts, we retain natural gas and NGLs as our compensation for providing these customers with our services. As of December 31, 2014, we are exposed to fluctuations in commodity prices in the near term on approximately 10% to 15% of the physical natural gas, NGLs and condensate we expect to receive as compensation for our services. Due to this unhedged commodity price exposure, our segment gross margin, representing revenue less cost of natural gas, generally increases when the prices of these commodities are rising and generally decreases when the prices are declining. As a result of entering into these derivative instruments, we have largely fixed the amount of cash that we will pay and receive in the future when we sell the residue gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate.

Logistics and Marketing

Our logistics and marketing business derives a majority of its segment gross margin from purchasing and receiving natural gas, NGLs and other products from our gathering, processing and transportation business and from third-party pipeline systems and processing plants and selling and delivering them to wholesale customers, such as distributors, refiners, fractionators, utilities, chemical facilities and power plants. We contract for third-party pipeline capacity under firm and interruptible transportation contracts for which the pipeline capacity depends on volumes of natural gas from our natural gas assets, which provides us with access to several third-party interstate and intrastate pipelines that can be used to transport natural gas and NGLs to primary market hubs where they can be sold to major customers for these products. Our logistics and marketing business also uses owned and leased trucks and specialized trailers and railcars to transport products such as NGLs, condensate and other liquid hydrocarbons to market. In some instances, our margin per unit of volume sold can be higher if the commodity being marketed requires specialized handling, treating, stabilization or other services.

Our logistics and marketing business also derives segment gross margin from the relative difference in natural gas and NGL prices between the contracted index at which the natural gas and NGLs are purchased and the index price at which they are sold, otherwise known as the "basis spread," which can vary over time or by location, as well as due to local supply and demand factors. Natural gas and NGLs purchased and sold by our logistics and marketing business is primarily priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. We enter into long-term, fixed-price purchase or sales contracts with our customers and generally will enter into offsetting hedge positions under the same or similar terms.

Estimation of Revenue and Cost of Natural Gas and Natural Gas Liquids

In order to permit the timely preparation of our consolidated financial statements, we must estimate our current month revenue and cost of natural gas and natural gas liquids. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data before our preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas and natural gas liquids based on the best available volume and price data for natural gas and natural gas liquids delivered and received, along with an adjustment of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas and natural gas liquids for each of the years ended December 31, 2014, 2013 and 2012. We believe that the assumptions underlying these estimates are not significantly different from the actual amounts due to the routine nature of these estimates and the consistency of our processes.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with original maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution are included in "Accounts payable and other" on our consolidated statements of financial position.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable when we determine that we will not collect all or part of an outstanding balance. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method.

Inventory

Inventory includes product inventory and materials and supplies inventory. We record all product inventories at the lower of our cost, as determined on a weighted average basis, or market value. Our product inventory consists of natural gas and liquid hydrocarbons, such as NGLs and condensate. Upon disposition, product inventory is recorded to "Cost of natural gas and natural gas liquids" at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

Materials and supplies inventory is either used during operations and charged to "Operating and maintenance" as incurred, or used for capital projects and new construction, and capitalized to "Property, plant and equipment, net."

Operational Balancing Agreements and Natural Gas Imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of natural gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a natural gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in-kind through the receipt or delivery of natural gas in the future. Natural gas imbalances are recorded as "Accrued receivables" and "Accrued purchases" on our consolidated statements of financial position using the posted index prices, which approximate market rates, or our weighted average cost of natural gas.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for: (1) assets purchased or constructed; (2) existing assets that are replaced, improved or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of its estimated useful life or the estimated remaining lives of the natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we recognize a gain or loss in our consolidated statements of income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of the recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of income.

Assessment of Recoverability of Goodwill

Goodwill represents the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized.

We test goodwill for impairment annually based on carrying values of our reporting units as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may be impaired. In testing goodwill for impairment, we make critical assumptions that include but are not limited to: (1) projections of future financial performance, which include commodity price and volume assumptions, (2) the expected growth rate of our assets, (3) residual values of the assets; and (4) market weighted average cost of capital. Impairment occurs when the carrying amount of a reporting unit's goodwill exceeds its implied fair value. We reduce the carrying value of goodwill to its fair value at the time we determine that impairment has occurred.

Assessment of Recoverability of Intangible Assets

Our intangible assets primarily consist of customer contracts for the purchase and sale of natural gas, natural gas supply opportunities and contributions we have made in aid of construction activities that will benefit our operations, as well as workforce contracts and customer relationships. We amortize these assets on a straight-line basis over the weighted average useful lives of the underlying assets, representing the period over which the assets are expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our intangible assets whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangible assets, we compare the carrying value to the undiscounted future cash flows we expect the intangible assets or the underlying assets to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangible assets, we write the intangible assets down to their fair value.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows as they relate to inventories, firm commitments and certain anticipated transactions.

We record all derivative financial instruments at fair market value in our Consolidated Statements of Financial Position. Price assumptions we use to value our non-qualifying derivative financial instruments can affect net income for each period. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. We may also use these inputs with internally developed methodologies that result in the best estimate of fair value. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, including credit risk of our counterparties. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Effective January 1, 2014, we elected to prospectively change the presentation of derivative assets and liabilities from a net basis to a gross basis in the Consolidated Statements of Financial Position. We adopted this change to provide more detailed information about the future economic benefits and obligations associated with our derivative activities in our Consolidated Statements of Financial Position. This change had no impact to the Consolidated Statements of Income, Net income (loss) per limited partner unit, or Partners' capital.

Qualified Hedges

If a derivative financial instrument qualifies and is designated as a cash flow hedge, which is a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in AOCI, a component of "Partners' capital," until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement until the underlying transaction occurs. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in "Cost of natural gas and natural gas liquids" for commodity hedges in the period in which the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two month period of time thereafter.

Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting treatment as set forth in the authoritative accounting guidance, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by the board of directors of Midcoast Holdings or a committee of senior management appointed by our General Partner. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

At inception, we formally document the relationship between the hedging instrument and the hedged item, the risk management objective, and the method used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, we regularly assess the creditworthiness of our counterparties to manage against the risk of default. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have derivative financial instruments associated with our commodity activities where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value included in “Cost of natural gas and natural gas liquids” or “Operating revenue” in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

The following transaction types do not receive hedge accounting and contribute to volatility in our earnings and in our cash flows upon settlement:

Commodity Price Exposures:

- **Transportation**—In our logistics and marketing business, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.
- **Storage**—In our logistics and marketing business, we use derivative financial instruments (i.e., natural gas, crude oil and NGL swaps) to hedge the relative difference between the injection price paid to

purchase and store natural gas, crude oil and NGLs and the withdrawal price at which these commodities are sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas, crude oil and NGLs injected and the price received upon withdrawal of these commodities from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of these commodities may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical commodities are recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical commodity is sold from storage. As a result, derivative financial instruments associated with our storage activities can increase volatility due to fluctuations in commodity prices until the underlying transactions are settled or offset.

- **Optional Natural Gas Processing Volumes—**In our gathering, processing and transportation business, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL and Crude Oil Forward Contracts**—In our logistics and marketing business, we use forward contracts to fix the price of NGLs and crude oil we purchase and sell to meet the demands of our customers that sell and purchase NGLs and crude oil. A subgroup of physical NGL and crude oil contracts qualify for the normal purchases and normal sales, or NPNS, scope exception. All other forward contracts are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL and crude oil prices until the forward contracts are settled.
- **Natural Gas Forward Contracts—**In our logistics and marketing business, we use forward contracts to sell natural gas to our customers. A subgroup of our physical natural gas contracts qualify for the NPNS, scope exception. All other contracts are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Condensate, Natural Gas and NGL Options**—In our gathering, processing and transportation business, we use options to hedge the forecasted commodity exposure of our condensate, NGLs and natural gas. Although options can qualify for hedge accounting treatment, pursuant to the authoritative accounting guidance, we have elected non-qualifying treatment. As such, our option premiums are expensed as incurred. These derivatives are being marked-to-market, with the changes in fair value recorded to earnings each period. As a result, our operating income is subject to volatility due to movements in the prices of condensate, NGLs and natural gas until the underlying long-term transactions are settled.

In all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or net realizable value basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at the lower of historical cost or net realizable value) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value to our derivative instruments and disclosures associated with our outstanding commodity activities. We define fair value as the expected price we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We employ a hierarchy which prioritizes the inputs we use to measure recurring fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.
- Level 2— We include in this category the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date, where pricing inputs are other than quoted prices in active markets for the identical instrument. This category includes both over-the-counter, or OTC, transactions valued using exchange traded pricing information in addition to assets and liabilities that we value using either models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted prices for assets and liabilities; (b) time value; (c) volatility factors; and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the assets and liabilities, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.
- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources (i.e., values supported by lesser volumes of market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 assets and liabilities primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. Additionally, Level 3 valuations may utilize modeled pricing inputs to derive forward valuations, which may include some or all of the following inputs: non-binding broker quotes, time value, volatility, correlation and extrapolation methods.

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust on a recurring basis each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply a mid-market pricing convention, which we refer to as the market approach, to value substantially all of our derivative instruments.

Our assets are adjusted for the non-performance risk of our counterparties using their current credit default swap spread rates. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and is also adjusted using a credit adjustment model incorporating inputs such as credit default swap rates, bond spreads, and default probabilities.

Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. As appropriate, valuations are adjusted for various factors such as credit and liquidity considerations. Actively traded external market quotes, data from pricing services and published indices are also used to value our derivative instruments. We may use these inputs along with internally developed methodologies that result in our best estimates of fair value.

Income Taxes

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the State of Texas. This tax is computed on our modified gross margin and we have determined the tax to be an income tax as set forth in authoritative accounting literature.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. We record the impact of changes in tax legislation on deferred income tax liabilities and assets in the period the legislation is enacted.

We recognize the tax effects of any uncertain tax positions as the largest amount that will more likely than not be realized upon ultimate settlement with a taxing authority having full knowledge of the position and all relevant facts. We recognize accrued interest income related to unrecognized tax benefits in interest income when the related unrecognized tax benefits are recognized.

Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in us is not available.

Commitments and Contingencies

We recognize liabilities for other commitments and contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as such costs are incurred.

Asset Retirement Obligations

Legal obligations exist for a minority of our right-of-way agreements due to requirements or landowner options that compel us to remove the pipe at final abandonment. Sufficient data exists with certain pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, our intentions, or the estimated economic life of the asset. Useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to allow us to reasonably estimate potential settlement dates and methods.

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO. Typically, we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for an ARO when assets are taken out of service or otherwise abandoned.

3. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

We allocate our net income among our General Partner and limited partners using the two-class method. Under the two-class method, we allocate our net income to our limited partners, our General Partner and the holders of our incentive distribution rights, or IDRs, in accordance with the terms of our partnership agreement. We also allocate any earnings in excess of distributions to our limited partners, our General Partner and the holders of the IDRs in accordance with the terms of our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and our limited partners based on their respective proportionate ownership interests in us, after taking into account distributions to be paid with respect to the IDRs, as set forth in our partnership agreement.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to Limited Partners	Percentage Distributed to General Partner
Minimum Quarterly Distribution	Up to \$0.3125	98 %	2 %
First Target Distribution	> \$0.3125 to \$0.359375	98 %	2 %
Second Target Distribution	> \$0.359375 to \$0.390625	85 %	15 %
Third Target Distribution	> \$0.390625 to \$0.468750	75 %	25 %
Over Third Target Distribution	In excess of \$0.468750	50 %	50 %

We determined basic and diluted net income per limited partner unit as follows:

	For the year ended December 31,		
	2014	2013[(1)]	2012[(1)]
	(in millions, except per unit amounts)		
Net income	$144.3	$ 53.9	$167.5
Less: Net income attributable to noncontrolling interest	80.2	33.7	102.2
Net income attributable to general and limited partner interests in Midcoast Energy Partners, L.P.	64.1	20.2	65.3
Less distributions:			
Total distributed earnings to our General Partner	1.2	0.8	0.7
Total distributed earnings to our limited partners	59.6	36.5	33.4
Total distributed earnings	60.8	37.3	34.1
Underdistributed (Overdistributed) earnings	$ 3.3	$(17.1)	$ 31.2
Weighted average limited partner units outstanding	45.2	29.2	26.7
Basic and diluted earnings per unit:			
Distributed earnings per limited partner unit[(2)]	$ 1.32	$ 1.25	$ 1.25
Underdistributed (Overdistributed) earnings per limited partner unit[(3)]	0.07	(0.57)	1.15
Net income per limited partner unit (basic and diluted)	$ 1.39	$ 0.68	$ 2.40

(1) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% that was retained by EEP.

(2) Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

(3) Represents the limited partners' share (98%) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and under distributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

4. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution, totaling approximately $6.6 million at December 31, 2014, and $8.8 million at December 31, 2013, are included in "Accounts payable and other" on our consolidated statements of financial position. At December 31, 2013, we reclassed a book overdraft of $49.1 million to "Accounts payable and other" on our consolidated statements of financial position.

5. INVENTORY

Our inventory is comprised of the following:

	December 31,	
	2014	2013
	(in millions)	
Materials and supplies	$ 0.7	$ 0.6
Crude oil inventory	2.0	12.6
Natural gas and NGL inventory	78.8	74.8
	$81.5	$88.0

The “Cost of natural gas and natural gas liquids” on our consolidated statements of income includes charges totaling $11.4 million, $3.4 million and $9.8 million for the years ended December 31, 2014, 2013 and 2012, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and NGLs, to reflect the current market value.

6. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment is comprised of the following:

	Depreciation Rates	December 31, 2014	December 31, 2013
		(in millions)	
Land	—	$ 11.1	$ 11.6
Rights-of-way	2.08%—7.14%	405.0	380.0
Pipelines	1.89%—6.70%	1,785.7	1,741.9
Pumping equipment, buildings and tanks	1.48%—6.67%	82.1	79.2
Compressors, meters and other operating equipment	1.8%—20.0%	2,074.8	1,993.2
Vehicles, office furniture and equipment	2.19%—33.33%	163.8	148.5
Processing and treating plants	2.21%—2.73%	516.0	514.4
Construction in progress		218.7	181.4
Total property, plant and equipment		5,257.2	5,050.2
Accumulated depreciation		(1,097.5)	(967.9)
Property, plant and equipment, net		$ 4,159.7	$4,082.3

During the year ended December 31, 2014, we evaluated our non-core Louisiana propylene pipeline for impairment in connection with the renegotiation of a contract. As a result of our analysis, we reduced the carrying value of $15.6 million to zero and recognized a corresponding non-cash impairment charge, which is reflected in “Operating and maintenance” expenses on our consolidated statements of income. This pipeline is part of our Gathering, Processing and Transportation segment.

We did not record any additional ARO for the years ended December 31, 2014 and December 31, 2013. For the year ended December 31, 2012, we recorded an ARO of $0.4 million when we recognized abandonment costs associated with assets we acquired through the September 2010 acquisition of the Elk City natural gas gathering and processing system. In our consolidated statements of income for the years ended December 31, 2014, 2013 and 2012, we recorded accretion expense of $0.2 million, $0.2 million and $0.1 million, respectively, for previously recorded asset retirement obligation liabilities.

We do not have any assets that are legally restricted for purposes of settling our ARO at December 31, 2014 and 2013. The following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for each of the years ended December 31, 2014 and 2013:

	2014	2013
	(in millions)	
Balance at beginning of period	$2.8	$2.6
Accretion expense	0.2	0.2
Balance at end of period	$3.0	$2.8

7. GOODWILL

Our goodwill originated from acquisitions by EEP that are fully associated with our gathering, processing and transportation business and our logistics and marketing business. For each of the years ended December 31, 2014 and 2013, the carrying amount of goodwill was $226.5 million consisting of $206.1 million and $20.4 million related to our gathering, processing and transportation and marketing and logistics businesses, respectively.

We test our goodwill for impairment annually primarily by using a discounted cash flow analysis. In addition, we also consider overall market capitalization of our business, cash flow measurement data and other factors. We completed our annual goodwill impairment test using amounts as of June 30, 2014, which did not indicate the existence of impairment to goodwill associated with any of our reporting units. The critical assumptions used in our analysis included the following:

1) A weighted average cost of capital of approximately 7.5%;
2) A terminal growth rate for our gathering, processing and transportation and logistics and marketing businesses of approximately 5.0% and 1.0%, respectively;
3) A capital structure consisting of approximately 40% debt and 60% equity; and
4) A long-term commodity price forecast using recent pricing information.

We did not record any goodwill impairment during the years ended December 31, 2014, 2013 and 2012. We have not observed any further events or circumstances subsequent to our analysis that would, more likely than not, reduce the fair value of our reporting units below the carrying amounts as of December 31, 2014.

8. INTANGIBLE ASSETS

The following table provides the gross carrying value, accumulated amortization and activity affecting amounts comprising each of our major classes of intangible assets.

	December 31, 2014							
	Gross Intangible Assets at December 31, 2013	Additions	Dispositions	Intangible Assets, Gross	Gross Accumulated Amortization at December 31, 2013	Amortization Expenses	Accumulated Amortization, Gross	Intangible Assets, Net
Natural Gas Opportunities	$291.0	$—	$—	$291.0	$(59.4)	$(10.3)	$(69.7)	$221.3
Customer Contracts	4.4	—	—	4.4	(1.7)	(0.4)	(2.1)	2.3
Other	27.3	8.0	—	35.3	(6.6)	(4.6)	(11.2)	24.1
Total intangible assets	$322.7	$ 8.0	$—	$330.7	$(67.7)	$(15.3)	$(83.0)	$247.7

	December 31, 2013							
	Gross Intangible Assets at December 31, 2012	Additions	Dispositions	Intangible Assets, Gross	Gross Accumulated Amortization at December 31, 2012	Amortization Expenses	Accumulated Amortization, Gross	Intangible Assets, Net
Natural Gas Opportunities	$291.0	$ —	$—	$291.0	$(49.0)	$(10.4)	$(59.4)	$231.6
Customer Contracts	4.4	—	—	4.4	(1.2)	(0.5)	(1.7)	2.7
Other	15.4	11.9	—	27.3	(3.4)	(3.2)	(6.6)	20.7
Total intangible assets	$310.8	$11.9	$—	$322.7	$(53.6)	$(14.1)	$(67.7)	$255.0

Natural gas intangibles include customer contracts and natural gas supply opportunities. Our customer contracts are comprised entirely of natural gas purchase and sale agreements associated with our gathering, processing and transportation business and our logistics and marketing business. We amortize our customer contracts on a straight-line basis over the weighted average useful life of the underlying reserves at the time of acquisition, which is approximately 25 years.

We obtained a portion of the natural gas supply opportunities in conjunction with the 2003 North Texas system acquisition. We obtained an additional portion of natural gas supply opportunities in connection with our September 2010 acquisition of the Elk City system. The value of these intangible assets is derived from growth opportunities present in the Barnett Shale producing zone of North Texas and the Granite Wash reservoir of the Anadarko basin in western Oklahoma and the Texas Panhandle. The natural gas supply opportunities relate entirely to our gathering, processing and transportation business. We are amortizing the natural gas supply opportunities on a straight line basis over the weighted average estimated useful life of the underlying reserves at the time of the acquisition, which is approximate 25 to 30 years.

Our other intangible assets are comprised of contributions we made in aid of construction for our gathering, processing and transportation business. Contributions in aid of construction has an estimated useful life of 25 years, and software has an estimated useful life of 3 years. In connection with our October 2010 acquisition of a common carrier trucking company, we recognized additional intangibles assets related to workforce contracts and customer relationships.

The following table presents our forecast of amortization expense associated with existing intangible assets for the years indicated:

2015	2016	2017	2018	2019
$15.4	$13.2	$11.9	$11.7	$11.7

9. EQUITY INVESTMENTS IN JOINT VENTURES

We have a 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties. The Texas Express NGL system consists of a 593-mile NGL intrastate transportation pipeline and a related NGL gathering system that were placed into service in the fourth quarter of 2013. Our investment in the Texas Express NGL system is presented in "Equity investment in joint ventures" on our consolidated statements of financial position. "Equity in earnings of joint ventures" on our consolidated statements of income represents our earnings related to these joint ventures. The following tables present summarized balance sheet information as of December 31, 2014 and 2013 and summarized income statement information for the years ended December 31, 2014, 2013, and 2012, for the Texas Express NGL system on a combined, 100% basis.

	December 31,	
	2014	2013
	(in millions)	
Current assets	$ 29.4	$ 15.2
Non-current assets	$1,035.0	$1,050.1
Current liabilities	$ 29.8	$ 55.7
Non-current liabilities	$ 0.9	$ 0.7
Total equity	$1,033.7	$1,008.9

	December 31,		
	2014	2013(1)	2012(1)
		(in millions)	
Operating revenues	$78.7	$ 5.1	$—
Operating expenses	$40.7	$ 9.2	$—
Net income	$37.9	$(4.1)	$—

(1) The Texas Express NGL system commenced start-up operations during the fourth quarter of 2013.

10. DEBT

The following table presents the carrying amounts, net of related unamortized discounts, of our consolidated debt obligations.

	December 31, 2014	December 31, 2013
	(in millions)	
Credit Agreement	$360.0	$335.0
3.56% Series A Senior Notes due 2019	75.0	—
4.04% Series B Senior Notes due 2021	175.0	—
4.42% Series C Senior Notes due 2024	150.0	—
Total	$760.0	$335.0

EEP incurred borrowing cost on behalf of our Predecessor, for which we reimbursed EEP and then recognized to the extent we were able to capitalize such costs to our construction related projects. The interest cost we incurred was directly offset by the amount of interest we capitalized on outstanding construction projects. Our interest cost for the years ended December 31, 2014, 2013, and 2012, is comprised of the following:

	December 31,		
	2014	2013[1]	2012[1]
		(in millions)	
Interest cost incurred	$17.8	$20.2	$11.9
Interest capitalized	1.1	18.5	11.9
Interest expense, net	$16.7	$ 1.7	$ —
Interest cost paid	$12.0	$20.2	$11.9
Weighted average interest rate[2]	3.6%	2.5%	—

(1) Prior to the Offering, the interest cost we recognized was an allocation of EEP's cost. In connection with the closing of the Offering, the Partnership, Midcoast Operating, and their material domestic subsidiaries, entered into the Credit Agreement to establish their own committed senior revolving credit facility.

(2) At December 31, 2012, MEP had no outstanding debt and no weighted average interest rate.

Debt Arrangements

Private Debt Issuance

On September 30, 2014, we completed a private offering of $400.0 million of notes consisting of three tranches of senior notes: $75.0 million of 3.56% Series A Senior Notes due in 2019; $175.0 million of 4.04% Series B Senior Notes due in 2021; and $150.0 million of 4.42% Series C Senior Notes due in 2024, collectively the Notes. All of the Notes pay interest semi-annually on March 31 and September 30, commencing on March 31, 2015. We received approximately $398.1 million in net proceeds, which were used to repay outstanding indebtedness and for other general partnership purposes. Using a portion of the net proceeds, we settled two interest rate swaps for a net payment of $0.9 million on September 30, 2014, which will be amortized to interest expense over the original five year hedge term.

The Notes were issued pursuant to a Note Purchase Agreement, or the Purchase Agreement, between us and the purchasers named therein. The Notes and all other obligations under the Purchase Agreement are unconditionally guaranteed by each of our domestic material subsidiaries pursuant to a guaranty agreement. Until such time as we obtain an investment grade rating from either Moody's or S&P and upon certain trigger events, we and the guarantors will grant liens in our assets (subject to certain excluded assets) to secure the obligations under the Notes. There are currently no liens associated with the Notes.

Additionally, the Purchase Agreement contains various covenants and restrictive provisions which limit the ability of us and our subsidiaries to incur certain liens or permit such liens to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests, incur or guarantee additional debt, repay subordinated debt or certain debt owed to affiliates prior to maturity, alter our lines of business, and enter into certain types of transactions with affiliates or subsidiaries that we are permitted to designate as unrestricted subsidiaries.

The Purchase Agreement contains events of default, indemnities, and covenants customary for transactions of this nature. These covenants and restrictive provisions are subject to exceptions and qualifications set forth in the Purchase Agreement. At such time as we obtain an investment grade rating from either Moody's or S&P, the obligation to provide security in certain circumstances will no longer be applicable to the Partnership or the guarantors and certain restrictions on prepayments of certain subordinated and affiliate will become less restricted.

The Purchase Agreement also requires compliance with two financial covenants. We must not permit the ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio), as of the end of any applicable four quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. We also must maintain, on a consolidated basis, as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four quarter period then ended of at least 2.50 to 1.00. At December 31, 2014, we were in compliance with the terms of our financial covenants under the Purchase Agreement.

The Notes are prepayable at our option, in whole or in part, provided that any such prepayment may incur a "make-whole" premium as specified in the Purchase Agreement. We must offer to prepay the notes upon the occurrence of any change of control. Under the Purchase Agreement, a change of control occurs if EEP or Enbridge ceases to control, directly or indirectly, our general partner. In addition, we must offer to prepay the Notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets.

In connection with our entry into the Purchase Agreement, we, along with EEP and the guarantors, entered into a subordination agreement pursuant to which EEP agreed to subordinate its right to payment on obligations owed by Midcoast Operating under each of the Financial Support Agreement and the Working Capital Agreements, both entered into by and between EEP and Midcoast Operating on November 13, 2013, and liens, if secured, to the rights of the holders under the Purchase Agreement, subject to the terms and conditions of the subordination agreement in favor and for the benefit of the holders of the Notes.

Credit Agreement

On November 13, 2013, we, Midcoast Operating, and our material domestic subsidiaries, entered into the Credit Agreement, by and among us, as co-borrower and a guarantor, Midcoast Operating, as co-borrower and a guarantor, our material subsidiaries party thereto as guarantors, Bank of America, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other lenders party thereto.

The Credit Agreement is a committed senior revolving credit facility (with related letter of credit and swing line facilities) that permits aggregate borrowings of up to, at any one time outstanding, $850.0 million, including up to initially: (1) $90.0 million under the letter of credit facility; and (2) $75.0 million under the swing line facility. Subject to customary conditions, we may request that the lenders' aggregate commitments be increased to an amount not to exceed $1.0 billion. The facility initially matured on November 13, 2016, subject to four one-year requests for extensions.

On September 30, 2014, we amended our Credit Agreement to, among other things, extend the maturity date from November 13, 2016, to September 30, 2017; however, $140.0 million of commitments will expire on the original maturity date of November 13, 2016. In connection with the amendment to our Credit Agreement, we entered into an amended and restated subordination agreement by and among us, Midcoast Operating, the other parties from time to time party thereto and EEP in favor of Bank of America, N.A., as administrative agent, and for the benefit of the administrative agent and the lenders party to the Credit Agreement, to accommodate the subordination agreement entered into in connection with the Purchase Agreement, described above under *"Private Debt Issuance."*

Loans under the Credit Agreement accrue interest at a per annum rate by reference, at our election, to the Eurodollar rate, which is equal to the London Interbank Offered Rate, or LIBOR, or a comparable or successor rate reasonably approved by the Administrative Agent, or base rate, in each case, plus an applicable margin. The applicable margin on Eurodollar (LIBOR) rate loans ranges from 1.75% to 2.75% and the applicable margin on base rate loans ranges from 0.75% to 1.75%, in each case determined based upon our total leverage ratio (as defined below) at the applicable time. At December 31, 2014, we had $360.0 million in outstanding borrowings under the Credit Agreement at a weighted average interest rate of 3.2%. Under the Credit Agreement, we had net borrowings of approximately $25.0 million during the year ended December 31, 2014, which includes gross borrowings of $6,920.0 million and gross repayments of $6,895.0 million.

A letter of credit fee is payable by the borrowers equal to the applicable margin for Eurodollar (LIBOR) rate loans times the daily amount available to be drawn under outstanding letters of credit. A commitment fee is payable by us equal to an applicable margin times the daily unused amount of the lenders' commitment, which applicable margin ranges from 0.30% to 0.50% based upon our total leverage ratio at the applicable time.

Each of our domestic material subsidiaries has unconditionally guaranteed all existing and future indebtedness and liabilities of the borrowers arising under the Credit Agreement and other loan documents, and each co-borrower has guaranteed all such indebtedness and liabilities of the other co-borrower. The credit facility is unsecured but security will be provided upon occurrence of any of the following: (1) for two consecutive quarters, the total leverage ratio as described below, exceeds 4.25 to 1.00, or 4.75 to 1.00 during acquisition periods, (2) uncured breach to certain terms and conditions of the Credit Agreement and (3) obtaining a non-investment grade initial debt rating from either S&P or Moody's.

Additionally, our Credit Agreement contains various covenants and restrictive provisions which limit our ability and that of Midcoast Operating and their subsidiaries to incur certain liens or permit them to exist, merge or consolidate with another company, dispose of assets, make distributions on or redeem or repurchase their equity interests during the continuance of a default, incur or guarantee additional debt, repay subordinated debt prior to maturity, make certain investments and acquisitions, alter their lines of business, enter into certain types of transactions with affiliates and enter into agreements that restrict their ability to perform certain obligations under the Credit Agreement or to make payments to a borrower or any of their material subsidiaries.

Our Credit Agreement also requires compliance with two financial covenants. We are not permitted to allow our ratio of consolidated funded debt to pro forma EBITDA (the total leverage ratio), as of the end of any applicable four-quarter period, to exceed 5.00 to 1.00, or 5.50 to 1.00 during acquisition periods. We must also maintain (on a consolidated basis), as of the end of each applicable four-quarter period, a ratio of pro forma EBITDA to consolidated interest expense for such four-quarter period then ended of at least 2.50 to 1.00. At December 31, 2014, we were in compliance with the terms of our financial covenants in the Credit Agreement.

These covenants are subject to exceptions and qualifications set forth in the Credit Agreement. At such time as we obtain an investment grade rating from either Moody's or S&P, certain covenants under the Credit Agreement will no longer be applicable to either the borrowers or the guarantors, or in some instances, any of them (including, but not limited to, the obligation to provide security in certain circumstances, certain restrictions on liens, investments and debt, and restrictions on dispositions). The Credit Agreement also contains customary representations, warranties, indemnities and remedies provisions.

Working Capital Credit Facility

On November 13, 2013, Midcoast Operating entered into a $250.0 million working capital credit facility with EEP as the lender. On October 30, 2014, Midcoast Operating exercised its right to terminate the working capital credit facility, effective November 30, 2014. At the time of the termination, there were no outstanding borrowings under this facility.

Before the termination of the working capital credit facility, borrowings under the facility accrued interest at a per annum rate of the LIBOR, plus 2.5%. Midcoast Operating paid a commitment fee on the unused commitment at a per annum rate of 0.4250%, payable each fiscal quarter. For the year ended December 31, 2014, approximately $0.6 million was paid by Midcoast Operating to EEP for commitment fees on the facility.

Financial Support Agreement

On November 13, 2013, Midcoast Operating entered into a Financial Support Agreement, between Midcoast Operating and EEP, pursuant to which EEP will provide letters of credit and guarantees, not to exceed $700.0 million in the aggregate at any time outstanding, in support of Midcoast Operating's and its wholly owned subsidiaries' financial obligations under derivative agreements and natural gas and NGL purchase agreements to which Midcoast Operating, or one or more of its wholly owned subsidiaries, is a party. Under the Financial Support Agreement, EEP's support of Midcoast Operating's and its wholly owned subsidiaries' obligations will terminate on the earlier to occur of: (1) the fourth anniversary of the closing of the Offering and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in the Partnership), less than 20% of the total outstanding limited partner interest in Midcoast Operating.

The annual costs that Midcoast Operating will incur under the Financial Support Agreement are based on the cumulative average amount of letters of credit and guarantees that EEP will provide on Midcoast Operating's and its wholly owned subsidiaries' behalf multiplied by a 2.5% annual fee. Based on the Partnership's 39% controlling interest in Midcoast Operating through June 30, 2014, and a 51.6% controlling interest in Midcoast Operating after June 30, 2014, the Partnership incurred $2.9 million of these annual costs for the year ended 2014, which is included in "Operating and maintenance-affiliate" on our consolidated statements of income.

The Financial Support Agreement also provides that if the Credit Agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. EEP has agreed to subordinate its right to payment on obligations owed under the Financial Support Agreement and liens, if secured, to the rights of the lenders under the Credit Agreement and the Purchase Agreement, subject to the terms and conditions of a subordination agreement.

Available Credit

At December 31, 2014, we have approximately $490.0 million available under the terms of our Credit Agreement, determined as follows:

	(in millions)
Total credit limit under Credit Agreement	$ 850.0
Amounts outstanding under Credit Agreement	(360.0)
Total amount available at December 31, 2014	$ 490.0

Maturities of Third Party Debt

The scheduled maturities of outstanding third-party debt, excluding any discounts at December 31, 2014, are summarized as follows in millions:

2015	$ —
2016	—
2017	360.0
2018	—
2019	75.0
Thereafter	325.0
Total	$760.0

Fair Value of Debt Obligations

The carrying amounts of our outstanding borrowings under the Credit Agreement approximate the fair values at December 31, 2014, and December 31, 2013, respectively, due to the short-term nature and frequent repricing of the amounts outstanding under these obligations. The outstanding borrowings under the Credit Agreement are included with our long-term debt obligations above since we have the ability and the intent to refinance the amounts outstanding on a long-term basis.

The approximate fair value of our fixed-rate debt obligations was $384.5 million at December 31, 2014. We determined the approximate fair values using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding. The fair value of our long-term debt obligations is categorized as Level 2 within the fair value hierarchy.

11. PARTNERS' CAPITAL

Prior to the Offering, partners' capital accounts were comprised of a 99.999% limited partner interest that was owned entirely by EEP and a 0.001% general partner interest that is owned by Midcoast OLP GP, L.L.C. (f/k/a Enbridge Midcoast Holdings, L.L.C.), or OLP GP, a wholly owned subsidiary of EEP. After the Offering, partners' capital accounts consist of general partner interests held by our General Partner, and limited partner interests held by EEP and the public. We paid cash distributions to EEP and OLP GP totaling $247.7 million prior to the Offering for a portion of the fiscal year ended December 31, 2013, and $302.2 million for the fiscal year ended December 31, 2012. These amounts were settled through "Distributions to Predecessor partner interests" as reflected on our consolidated statements of cash flows. No cash distributions were made to our partners in the period after the Offering through December 31, 2013.

Midcoast Operating paid cash distributions totaling $95.9 million to EEP during the year ended December 31, 2014 for its ownership interest in Midcoast Operating. In addition, we paid cash distributions totaling $8.5 million to EEP during the year ended December 31, 2014 for its ownership interest in us. These amounts are reflected in "Distributions to noncontrolling interest" and "Distributions to partners", respectively, on our consolidated statements of cash flows.

Prior to the Offering, EEP also provided us with cash management services through a centralized treasury system. As a result, all of our charges and cost allocations covered by the centralized treasury system were deemed to have been paid by us to EEP, in cash, during the period in which the cost was recorded in the financial statements. In addition, all of our cash receipts were advanced to EEP as they were received. As a result of using EEP's centralized treasury system, the excess of cash receipts advanced to EEP over the charges and cash allocation is reflected as distributions to Predecessor partner interests in the statements of partners' capital.

As of December 31, 2014 and 2013, our capital accounts consist of general partner interests held by Midcoast Holdings, which is a wholly owned subsidiary of EEP, and limited partner interests held by EEP and the public. At December 31, 2014 and 2013, our equity interests were distributed as follows:

	2014	2013
Limited Partner Interests held by EEP	52%	52%
Limited Partner Interests held by the Public	46%	46%
General Partner Interest	2%	2%
	100%	100%

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Midcoast Holdings, L.L.C., our General Partner, during the year ended December 31, 2014.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash Distributed
			(in millions, except per unit amounts)	
October 30, 2014	November 7, 2014	November 14, 2014	$0.33750	$15.6
July 30, 2014	August 7, 2014	August 14, 2014	$0.32500	$15.0
April 29, 2014	May 8, 2014	May 15, 2014	$0.31250	$14.4
January 29, 2014	February 7, 2014	February 14, 2014	$0.16644	$ 7.7

Acquisition of Additional Interests in Midcoast Operating

On July 1, 2014, we acquired a 12.6% limited partner interest in Midcoast Operating from EEP for $350.0 million, which brought our total ownership interest in Midcoast Operating to 51.6%. This transaction represents our first acquisition of additional interests in Midcoast Operating since the Offering. We do not know when, or if, any additional interests will be offered to us to purchase.

We recorded the change in our total ownership interest as an equity transaction. No gain on the acquisition was recognized in our consolidated statements of income or comprehensive income. We reduced the book value of the related "Noncontrolling interest" in Midcoast Operating by $622.0 million in our consolidated statement of financial position as of September 30, 2014. The $272.0 million difference between the acquisition price and the book value of the noncontrolling interest was recorded as an increase to the partners' capital accounts on a pro-rata basis. In addition, accumulated other comprehensive income, or AOCI, of $0.9 million representing the noncontrolling interest of AOCI for Midcoast Operating was reclassified to AOCI attributable to us.

Securities Authorized for Issuance under Equity Compensation Plans

In connection with, but prior to, the Offering, we adopted the 2013 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or our LTIP, under which we may issue long-term equity based awards to directors, officers and employees of our General Partner or its affiliates, or to any consultants of our General Partner or other individuals who perform services for us. Directors and consultants who are not also employees of our General Partner or its affiliates will not be eligible to receive awards under the LTIP. We have filed a registration statement with the SEC registering the issuance of 3,750,000 Class A common units that are issuable pursuant to awards granted under our LTIP. As of December 31, 2014, we have not issued any Class A common units under our LTIP.

Shelf-Registration Statement

From time to time, we may seek to satisfy liquidity needs through the issuance of registered debt or equity securities. To that end, in December 2014, we filed a shelf registration statement on Form S-3 with the Securities and Exchange Commission with a proposed aggregate offering price for all securities registered of $1.5 billion, which became effective on February 5, 2015.

12. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

Enbridge and its affiliates provide management, administrative, operational and workforce related services to us. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the administrative and operational services charged to us.

We do not directly employ any of the individuals responsible for managing or operating our business. We have historically obtained managerial, administrative and operational services from EEP's general partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, EEP, Enbridge Management and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse EEP's general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

Intercorporate Services Agreement

On November 13, 2013, we entered into an Intercorporate Services Agreement with EEP, pursuant to which EEP and its affiliates provides us with services as set forth in the agreement, which include such functions as management, accounting, operational and administrative personnel, among other such functions as we may require.

Under the Intercorporate Services Agreement, we reimburse EEP and its affiliates for the costs and expenses incurred in providing us with such services. The allocation methodology under which we reimburse EEP and its affiliates for the provision of general administrative and operational services to Midcoast Operating does not differ from the historical allocation methodology applied to Midcoast Operating under its prior services agreements with Enbridge and certain of its affiliates. EEP has agreed to reduce the amounts payable for general and administrative expenses that otherwise would have been allocable to Midcoast Operating by $25.0 million annually. As a result, for the year ended December 31, 2014, we recognized $25.0 million as a reduction to "Due to general partner and affiliates" with the offset to "Noncontrolling interest" in our consolidated statements of financial position.

The affiliate amounts incurred by us through EEP for services received pursuant to the Intercorporate Services Agreement and, for periods prior to November 13, 2013, the services agreements with Enbridge and certain of its affiliates are reflected in "Operating and maintenance—affiliate" and "General and administrative—affiliate" on our consolidated statements of income. For the period ended December 31, 2014, we recognized workforce reduction costs of $4.8 million, which are included in "General and administrative—affiliate" on our consolidated statements of income.

Enbridge and Enbridge Management and their respective affiliates allocated direct workforce costs to us for our construction projects of $5.8 million, $6.8 million and $6.4 million as of December 31, 2014, 2013 and 2012, respectively, that we recorded as additions to "Property, plant and equipment, net" on our consolidated statements of financial position.

Insurance Allocation Agreement

We participate in the comprehensive insurance program that is maintained by Enbridge for its benefit and the benefit of its subsidiaries. On November 13, 2013, we entered into an Amended and Restated Allocation

Agreement, or the Insurance Allocation Agreement, by and among us, Enbridge, EEP and Enbridge Income Fund Holdings Inc., in order to participate in the comprehensive insurance program that Enbridge maintains for itself and its subsidiaries. Under this agreement, in the unlikely event that multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis.

Affiliate Revenues and Purchases

We sell natural gas, NGLs and crude oil at market prices on the date of sale to Enbridge and its affiliates. The sales to Enbridge and its affiliates are presented in "Operating revenue—affiliate" on our consolidated statements of income. We also purchase natural gas, NGLs and crude oil at market prices on the date of purchase from Enbridge and its affiliates for sale to third parties. The purchases of natural gas, NGLs and crude oil from Enbridge and its affiliates are presented in "Cost of natural gas and natural gas liquids—affiliate" on our consolidated statements of income.

Also, included in "Cost of natural gas and natural gas liquids—affiliate", for the years ended December 31, 2014 and 2013, are $21.9 million and $3.2 million, respectively, of pipeline transportation and demand fees from Texas Express NGL system. Our logistics and marketing business has made commitments to transport up to 120,000 Bpd of NGLs on the Texas Express NGL system from 2014 to 2022.

Routine purchases and sales with affiliates are settled monthly through MEP's centralized treasury function at terms that are consistent with third-party transactions for the year ended December 31, 2014. For the years ended December 31, 2013 and 2012, our Predecessor's routine purchases and sales with affiliates were settled monthly through EEP's centralized treasury function at terms that were consistent with third-party transactions. Routine purchases and sales with affiliates that have not yet been settled are included in "Due from general partner and affiliates" and "Due to general partner and affiliates" on our consolidated statements of financial position.

Conflicts of Interest

Under our partnership agreement, our General Partner has a duty to manage us in a manner it believes is in our best interests. However, because our General Partner is a wholly owned subsidiary of EEP, the officers and directors of our General Partner also have a duty to manage the business of our General Partner in a manner that they believe is in the best interests of EEP. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our General Partner and its affiliates, including EEP, on the other hand. In addition, our General Partner may determine to manage our business in a way that directly benefits EEP's businesses, rather than indirectly benefitting EEP solely through its ownership interests in us. All of these actions are permitted under our partnership agreement and will not be a breach of any duty (fiduciary or otherwise) of our General Partner. As permitted by Delaware law, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our General Partner with contractual standards governing the duties of the General Partner and contractual methods of resolving conflicts of interest. The effect of these provisions is to restrict the remedies available to our unitholders for actions that might otherwise constitute breaches of our General Partner's fiduciary duties. Our partnership agreement also provides that affiliates of our General Partner, including EEP and Enbridge, are not restricted from competing with us, and neither our General Partner nor its affiliates have any obligation to present business opportunities to us.

Sale of Accounts Receivable

We and certain of our subsidiaries are parties to a receivables purchase arrangement pursuant to a receivables purchase agreement, dated June 28, 2013, as amended on September 20, 2013 and December 2, 2013, which we refer to as the Receivables Agreement, with an indirect wholly owned subsidiary of Enbridge. The Receivables Agreement and the transactions contemplated thereby were approved by a special committee of the board of directors of Enbridge Management, which prior to the Offering, effectively managed the business of the Predecessor through its management of EEP's business. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivables and accrued receivables, or the receivables, of participating sellers, consisting of certain of our subsidiaries and certain EEP subsidiaries up to an aggregate monthly maximum of $450.0 million net of receivables that have not been collected. Following the sale and transfer of the receivables to the Enbridge subsidiary, the receivables are deposited in an account of that subsidiary, and ownership and control are vested in that subsidiary. The Enbridge subsidiary has no recourse with respect to the receivables acquired from these operating subsidiaries under the terms of and subject to the conditions stated in the Receivables Agreement.

We and EEP each act in an administrative capacity as collection agent on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. Prior to the amendment to the Receivables Agreement on December 2, 2013 EEP was the sole collection agent on behalf of the Enbridge subsidiary. We and EEP have no other involvement with the purchase and sale of the receivables pursuant to the Receivables Agreement. The Receivables Agreement terminates on December 30, 2016.

Consideration for the receivables sold is equivalent to the carrying value of the receivables less a discount for credit risk. The difference between the carrying value of the receivables sold and the cash proceeds received is recognized in "General and administrative—affiliate" expense in our consolidated statements of income. For the years ended December 31, 2014 and 2013, the expense stemming from the discount on the receivables sold was $0.9 million and $0.4 million, respectively.

For the years ended December 31, 2014 and 2013, we sold and derecognized $3,484.0 million and $1,566.7 million, respectively, of receivables to an indirect wholly owned subsidiary of Enbridge. For the years ended December 31, 2014 and 2013, we received cash proceeds of $3,483.1 million and $1,566.3 million, respectively. As of December 31, 2014 and 2013, $272.7 million and $273.6 million, respectively, of the receivables were outstanding and had not been collected on behalf of the Enbridge subsidiary.

As of December 31, 2014 and 2013, we have $17.7 million and $61.5 million, respectively, included in "Restricted cash" on our consolidated statements of financial position, consisting of cash collections related to the receivables sold that have yet to be remitted to the Enbridge subsidiary.

13. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to the operating activities of our gathering, processing, and transportation and logistics and marketing businesses, and we are, at times, subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover payment for environmental liabilities from insurance or otherwise, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our gathering, processing and transportation and logistics and marketing businesses. We continue to voluntarily monitor past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations. As of December 31, 2014, we had $0.2 million of accrued environmental liabilities included in "Other long-term liabilities." As of December 31, 2013, we did not record any environmental liabilities.

Natural Gas in Custody

Approximately 40% of the natural gas volumes handled by our gathering, processing and transportation business are transported for customers on a contractual basis. We purchase the remaining volumes and sell to third parties downstream of the purchase point. At any point in time, the value of our customers' natural gas in the custody of our gathering, processing and transportation assets is not significant to our operating results, cash flows, or financial position.

Rights-of-Way

As part of our pipeline construction process, we must obtain certain rights-of-way from landowners whose property the pipeline will cross. Rights-of-way that we buy are capitalized as part of "Property, plant and equipment, net" in our consolidated statements of financial position. Rights-of-way that we lease are expensed. We have recorded expenses of $1.5 million, $0.3 million and $0.9 million for the leased right-of-way agreements for the years ended December 31, 2014, 2013, and 2012, respectively.

Legal and Regulatory Proceedings

We are a participant in a number of legal proceedings arising in the ordinary course of business. Some of these proceedings are not covered, in whole or in part, by insurance. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial position, results of operations or cash flows. In addition, we are not aware of any significant legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Future Minimum Commitments

As of December 31, 2014, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

	2015	2016	2017	2018	2019	Thereafter	Total
				(in millions)			
Purchase commitments[(1)]	$ 53.7	$ —	$ —	$ —	$ —	$ —	$ 53.7
Other operating leases	22.5	21.6	20.7	14.2	14.1	341.3	434.4
Right-of-way	0.7	0.5	0.2	0.2	—	0.5	2.1
Product purchase obligations[(2)]	14.8	8.3	14.7	24.5	25.5	112.5	200.3
Transportation/Service contract obligations[(3)]	63.3	58.3	99.5	109.1	113.8	403.5	847.5
Fractionation agreement obligations[(4)]	70.1	70.1	70.1	70.1	70.1	235.0	585.5
Total	$225.1	$158.8	$205.2	$218.1	$223.5	$1,092.8	$2,123.5

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our growth projects.

(2) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at the approximate market value at the time of delivery.

(3) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

(4) The fractionation agreement obligations represent the minimum payment amounts for firm fractionation of our NGL supply that we reserve at third party fractionation facilities.

The purchases made under our non-cancelable commitments for the years ended December 31, 2014, 2013 and 2012 were $1.7 billion, $334.4 million and $117.0 million, respectively.

The consolidated operating expenses include lease and rental expense amounts of $10.7 million, $17.3 million and $23.1 million during the years ended December 31, 2014, 2013 and 2012, respectively.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL and condensate sales and the corresponding cost of natural gas we purchase for processing. Our exposure to commodity price risk exists within both of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options, and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with commodity price risks through 2018 in accordance with our risk management policies.

Our Predecessor historically had related party derivative transactions executed on behalf of EEP that were contracted through our Predecessor prior to the Offering and were allocated to EEP. These transactions were contracted to hedge the forward price of EEP's crude oil length inherent to the operation of pipelines and to hedge EEP's interest payments of variable rate debt obligations. Subsequent to the Offering, these transactions were re-contracted through EEP and are no longer allocated from us.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31,	
	2014	2013
	(in millions)	
Other current assets	$164.7	$ 10.3
Other assets, net	91.5	10.3
Accounts payable and other[1]	(74.4)	(21.1)
Other long-term liabilities	(22.5)	(0.9)
Due from General Partner and affiliates	0.3	—
	$159.6	$ (1.4)

(1) Includes $28.4 million of cash collateral at December 31, 2014.

The changes in the assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of natural gas, NGL and crude oil sales and purchase contracts.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	December 31,	
	2014	2013
	(in millions)	
Counterparty Credit Quality[1]		
AAA	$ 0.1	$ 0.2
AA[2]	74.4	(2.1)
A	67.1	(1.1)
Lower than A	18.0	1.6
	$159.6	$(1.4)

(1) As determined by nationally-recognized statistical ratings organizations.
(2) Includes $28.4 million of cash collateral at December 31, 2014.

As the net value of our derivative financial instruments has increased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also increased. When credit thresholds are met pursuant to the terms of our ISDA® financial contracts, we have the right to require collateral from our counterparties. We include any cash collateral received in the balances listed above. As of December 31, 2014, we are holding cash collateral of $28.4 million on our asset exposures and none as of December 31, 2013. Cash collateral is classified as "Restricted cash" in our consolidated statements of financial position. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At December 31, 2014 and 2013, we had credit concentrations in the following industry sectors, as presented below:

	December 31,	
	2014	**2013**
	(in millions)	
United States financial institutions and investment banking entities[1]	$ 88.5	$ 2.4
Non-United States financial institutions	30.7	0.1
Integrated oil companies	1.7	(1.6)
Other	38.7	(2.3)
	$159.6	$(1.4)

(1) Includes $28.4 million of cash collateral at December 31, 2014.

Gross derivative balances are presented below before the effects of collateral received or posted and without the effects of master netting arrangements. Both our assets and liabilities are adjusted for non-performance risk, which is statistically derived. This credit valuation adjustment model considers existing derivative asset and liability balances in conjunction with contractual netting and collateral arrangements, current market data such as credit default swap rates and bond spreads and probability of default assumptions to quantify an adjustment to fair value. For credit modeling purposes, collateral received is included in the calculation of our assets, while any collateral posted is excluded from the calculation of the credit adjustment. Our credit exposure for these over-the-counter, or OTC, derivatives is directly with our counterparty and continues until the maturity or termination of the contracts.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Financial Position Location	Asset Derivatives Fair Value at December 31, 2014	Asset Derivatives Fair Value at December 31, 2013[3]	Liability Derivatives Fair Value at December 31, 2014	Liability Derivatives Fair Value at December 31, 2013[3]
		(in millions)			
Derivatives designated as hedging instruments[1]					
Commodity contracts	Other current assets	$ 26.1	$ 2.0	$ —	$ (0.6)
Commodity contracts	Other assets	2.1	3.5	—	(0.5)
Commodity contracts	Accounts payable and other[2]	—	1.9	—	(12.7)
Commodity contracts	Other long-term liabilities	—	0.6	—	(1.4)
		28.2	8.0	—	(15.2)
Derivatives not designated as hedging instruments					
Commodity contracts	Other current assets	138.6	9.0	—	(0.1)
Commodity contracts	Other assets	89.4	10.7	—	(3.4)
Commodity contracts	Accounts payable and other[2]	—	5.4	(46.0)	(15.7)
Commodity contracts	Other long-term liabilities	—	—	(22.5)	(0.1)
Commodity contracts	Due from general partner and affiliates	0.3	—	—	—
		228.3	25.1	(68.5)	(19.3)
Total derivative instruments		$256.5	$33.1	$(68.5)	$(34.5)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.

(2) Excludes total of $28.4 million of cash collateral at December 31, 2014.

(3) Includes both affiliate and third party transactions.

Accumulated Other Comprehensive Income

Also included in AOCI are unrecognized losses of approximately $0.1 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings.

During the twelve month period ended December 31, 2014 and 2013, unrealized commodity hedge losses of $0.2 million and gains of $1.7 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $26.4 million, representing unrealized net gains from our cash flow hedging activities based on pricing and positions at December 31, 2014, will be reclassified from AOCI to earnings during the next 12 months.

We used a portion of the net proceeds of our September 30, 2014 debt issuance of $400.0 million to settle treasury locks we entered in July 2014 to hedge the interest payments on a portion of these obligations. The $0.9 million settlement amount is being amortized from AOCI to interest expense over the 5 year original hedge term.

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivative (Effective Portion)	Location of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCI to Earnings (Effective Portion)	Location of Gain (loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]	Amount of Gain (Loss) Recognized in Earnings on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]
		(in millions)			
For the year ended December 31, 2014					
Commodity contracts	$ 29.9	Cost of natural gas and natural gas liquids	$(5.8)	Cost of natural gas and natural gas liquids	$5.6
For the year ended December 31, 2013					
Commodity contracts	$(16.5)	Cost of natural gas and natural gas liquids	$ 2.7	Cost of natural gas and natural gas liquids	$3.3
For the year ended December 31, 2012					
Commodity contracts	$ 41.8	Cost of natural gas and natural gas liquids	$ 0.1	Cost of natural gas and natural gas liquids	$3.1

(1) Includes only the ineffective portion of derivatives that are designated as hedging instruments and does not include net gains or losses associated with derivatives that do not qualify for hedge accounting treatment.

Components of Accumulated Other Comprehensive Income/(Loss)

	Cash Flow Hedges
	(in millions)
Balance at December 31, 2013	$ (3.1)
Other Comprehensive Income before reclassifications[1][2]	13.0
Amounts reclassified from AOCI[3][4]	1.8
Tax benefit (expense)[5]	(0.1)
Net other comprehensive income	$14.7
Balance at December 31, 2014	$11.6

(1) Excludes NCI gain of $10.9 million reclassified from AOCI at December 31, 2014.

(2) Excludes NCI gain of $0.9 million reclassified from AOCI related to the acquisition of additional interests in MOLP at December 31, 2014.

(3) Excludes NCI gain of $4.0 million reclassified from AOCI at December 31, 2014.

(4) For additional details on the amounts reclassified from AOCI, reference the *Reclassifications from Accumulated Other Comprehensive Income* table below.

(5) Excludes NCI loss of $0.1 million reclassified from AOCI at December 31, 2014.

Reclassifications from Accumulated Other Comprehensive Income

	December 31,		
	2014	2013	2012
	(in millions)		
Losses (gains) on cash flow hedges:			
Commodity Contracts[1][2]	$1.8	$(2.7)	$(0.1)
Total Reclassifications from AOCI	$1.8	$(2.7)	$(0.1)

(1) Loss (gain) reported within "Cost of natural gas and natural gas liquids" in the consolidated statements of income.

(2) Excludes NCI gain of $4.0 million reclassified from AOCI for the year ended December 31, 2014.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings[1]	December 31, 2014	2013[4]	2012[4][5]
		Amount of Gain or (Loss) Recognized in Earnings[2] (in millions)		
Commodity contracts	Operating revenue	$ 23.7	$ (3.0)	$ —
Commodity contracts	Operating revenue—affiliate	0.3	—	—
Commodity contracts	Cost of natural gas and natural gas liquids[3]	136.8	(7.9)	19.5
Total		$160.8	$(10.9)	$19.5

(1) Does not include settlements associated with derivative instruments that settle through physical delivery.

(2) Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.

(3) Includes settlement gains of $8.0 million, settlement losses of $4.6 million, and settlement gains of $21.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

(4) Includes both affiliate and third party transactions.

(5) The effects of derivative instruments on consolidated statements of income have been revised to include settlement on derivatives not designated as hedge instruments of a gain of $21.4 million for the year ended December 31, 2012.

We record the fair market value of our derivative financial and physical instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a gross basis. However, the terms of the ISDA®, which governs our financial contracts and our other master netting agreements, allow the parties to elect in respect of all transactions under the agreement, in the event of a default and upon notice to the defaulting party, for the non-defaulting party to set-off all settlement payments, collateral held and any other obligations (whether or not then due), which the non-defaulting party owes to the defaulting party. The effect of the rights of set-off are outlined below.

Offsetting of Financial Assets and Derivative Assets

	As of December 31, 2014				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position[1]	Net Amount
			(in millions)		
Description:					
Derivatives	$256.5	$—	$256.5	$(91.8)	$164.7

	As of December 31, 2013				
	Gross Amount of Recognized Assets	Gross Amount Offset in the Statement of Financial Position	Net Amount of Assets Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
			(in millions)		
Description:					
Derivatives	$33.1	$(12.5)	$20.6	$(1.9)	$18.7

(1) Includes $28.4 million of cash collateral at December 31, 2014.

Offsetting of Financial Liabilities and Derivative Liabilities

	As of December 31, 2014				
	Gross Amount of Recognized Liabilities(1)	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position(1)	Net Amount
Description:					
Derivatives	$(96.9)	$—	$(96.9)	$91.8	$(5.1)

	As of December 31, 2013				
	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Statement of Financial Position	Net Amount of Liabilities Presented in the Statement of Financial Position	Gross Amount Not Offset in the Statement of Financial Position	Net Amount
Description:					
Derivatives	$(34.5)	$12.5	$(22.0)	$1.9	$(20.1)

(1) Includes $28.4 million of cash collateral at December 31, 2014.

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2014 and 2013. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	December 31, 2014					December 31, 2013			
	Level 1	Level 2	Level 3	Collateral	Total	Level 1	Level 2	Level 3	Total
					(in millions)				
Commodity contracts:									
Financial	$—	$19.1	$ 42.7	—	61.8	$—	$(3.4)	$(6.9)	$(10.3)
Physical	—	—	19.5	—	19.5	—	—	0.5	0.5
Commodity options	—	—	106.7	—	106.7	—	—	8.4	8.4
	—	19.1	168.9	—	188.0	—	(3.4)	2.0	(1.4)
Cash Collateral	—	—	—	(28.4)	(28.4)		—	—	—
Total	$—	$19.1	$168.9	$(28.4)	$159.6	$—	$(3.4)	$ 2.0	$ (1.4)

Qualitative Information about Level 3 Fair Value Measurements

Data from pricing services and published indices are used to value our Level 3 derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value. The inputs listed in the table below would have a direct impact on the fair values of the listed instruments. The significant unobservable inputs used in the fair value measurement of the commodity derivatives (Natural Gas, NGLs, and Crude Oil) are forward commodity prices. The significant unobservable inputs used in determining the fair value measurement of options are price and volatility. Increases/(decreases) in the forward commodity price in isolation would result in significantly higher/(lower) fair values for long positions, with offsetting impacts to short positions. Increases/(decreases) in volatility would increase/(decrease) the value for the holder of the option. Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the credit valuation adjustment would decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2014[2]	Valuation Technique	Unobservable Input	Range[1]			Units
				Lowest	Highest	Weighted Average	
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$ 0.6	Market Approach	Forward Gas Price	2.55	3.72	3.04	MMBtu
NGLs	42.1	Market Approach	Forward NGL Price	0.48	1.14	0.64	Gal
Commodity Contracts - Physical							
Natural Gas	1.5	Market Approach	Forward Gas Price	1.55	4.08	3.08	MMBtu
Crude Oil	(0.9)	Market Approach	Forward Crude Oil Price	49.57	55.60	53.51	Bbl
NGLs	18.9	Market Approach	Forward NGL Price	0.06	1.21	0.54	Gal
Commodity Options							
Natural Gas, Crude and NGLs	106.7	Option Model	Option Volatility	19%	94%	36%	
Total Fair Value	$168.9						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gallon, or Gal, for NGLs, Bbl for Crude Oil and dollars per Megawatt hour, or MWh, for Power.

(2) Fair values include credit valuation adjustments of approximately $1.0 million of losses.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013[2]	Valuation Technique	Unobservable Input	Range[1]			Units
				Lowest	Highest	Weighted Average	
	(in millions)						
Commodity Contracts - Financial							
Natural Gas	$—	Market Approach	Forward Gas Price	3.64	4.41	4.14	MMBtu
NGLs	(6.9)	Market Approach	Forward NGL Price	1.00	2.13	1.38	Gal
Commodity Contracts - Physical							
Natural Gas	1.1	Market Approach	Forward Gas Price	3.36	4.82	4.15	MMBtu
Crude Oil	(0.5)	Market Approach	Forward Crude Oil Price	86.37	103.04	97.24	Bbl
NGLs	(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Commodity Options							
Natural Gas, Crude and NGLs	8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 2.0						

(1) Prices are in dollars per MMBtu for Natural Gas, dollars per Gal for NGLs and dollars per Bbl for Crude Oil.

(2) Fair values include credit valuation adjustments of approximately $0.1 million of gains.

Level 3 Fair Value Reconciliation

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2014 to December 31, 2014. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
	(in millions)			
Beginning balance as of January 1, 2014	$ (6.9)	$ 0.5	$ 8.4	$ 2.0
Transfer out of Level 3[1]	—	—	—	—
Gains or losses:				
Included in earnings	30.2	48.2	101.7	180.1
Included in other comprehensive income	16.9	—	—	16.9
Purchases, issuances, sales and settlements:				
Purchases	—	—	0.7	0.7
Sales	—	—	(2.1)	(2.1)
Settlements[2]	2.5	(29.2)	(2.0)	(28.7)
Ending balance as of December 31, 2014	$42.7	$ 19.5	$106.7	$168.9
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$42.2	$ 19.0	$100.4	$161.6
Amounts reported in operating revenue	$ —	$ 24.0	$ —	$ 24.0

(1) Our policy is to recognize transfers as of the last day of the reporting period.

(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair value of expected cash flows of our outstanding commodity based swaps and physical contracts at December 31, 2014 and 2013.

	At December 31, 2014						At December 31, 2013	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2015								
Swaps								
Receive variable/pay fixed	Natural Gas	896,915	$ 2.94	$ 3.67	$ —	$ (0.7)	$—	$—
	NGL	225,850	$35.24	$65.37	$ —	$ (6.8)	$—	$—
	Crude Oil	912,250	$56.73	$86.82	$ —	$(27.4)	$—	$—
Receive fixed/pay variable	Natural Gas	3,645,440	$ 3.95	$ 2.93	$ 3.7	$ —	$—	$—
	NGL	1,980,850	$46.91	$27.11	$39.2	$ —	$ 1.5	$(1.1)
	Crude Oil	1,244,400	$90.83	$56.74	$42.4	$ —	$ 1.7	$—
Receive variable/pay variable	Natural Gas	59,606,800	$ 2.89	$ 2.89	$ 1.5	$ (1.7)	$ 0.1	$—
Physical Contracts								
Receive variable/pay fixed	Natural Gas	232,400	$ 3.09	$ 2.99	$ —	$ —	$—	$—
	NGL	206,300	$22.54	$39.95	$ —	$ (3.6)	$—	$—
	Crude Oil	11,300	$53.44	$56.27	$ —	$ —	$—	$—
Receive fixed/pay variable	Natural Gas	290,114	$ 3.02	$ 3.18	$ —	$ —	$—	$—
	NGL	1,042,921	44.60	25.58	19.8	—	$—	$—
	Crude Oil	65,000	$62.46	$54.00	$ 0.5	$ —	$—	$—
Receive variable/pay variable	Natural Gas	148,689,068	$ 2.95	$ 2.95	$ 2.2	$ (1.0)	$ 0.5	$(0.1)
	NGL	7,221,805	$22.68	$22.30	$ 3.7	$ (1.0)	$—	$—
	Crude Oil	558,553	$50.57	$53.07	$ 0.3	$ (1.7)	$—	$—
Portion of contracts maturing in 2016								
Swaps								
Receive variable/pay fixed	Natural Gas	181,435	$ 3.15	$ 3.85	$ —	$ (0.1)	$—	$—
	Crude Oil	415,950	$62.96	$82.69	$ —	$ (8.1)	$—	$—
Receive fixed/pay variable	Natural Gas	75,000	$ 3.48	$ 3.52	$ —	$ —	$—	$—
	NGL	823,500	$39.64	$28.18	$ 9.3	$ —	$—	$—
	Crude Oil	415,950	$85.08	$62.96	$ 9.1	$ —	$ 0.7	$—
Receive variable/pay variable	Natural Gas	20,587,000	$ 3.30	$ 3.29	$ 0.5	$ (0.3)	$—	$—
Physical Contracts							—	—
Receive fixed/pay variable	NGL	1,788	$28.67	$25.71	$ —	$ —	$—	$—
Receive variable/pay variable	Natural Gas	34,834,479	$ 3.40	$ 3.39	$ 0.7	$ (0.4)	$ 0.1	$—
Portion of contracts maturing in 2017								
Swaps								
Receive fixed/pay variable	NGL	365,000	$24.78	$22.79	$ 0.7	$ —	$—	$—
	Crude Oil	365,000	$69.35	$66.97	$ 0.8	$ —		
Physical Contracts								
Receive variable/pay variable	Natural Gas	14,909,743	$ 3.77	$ 3.76	$ 0.2	$ (0.1)	$—	$—
Portion of contracts maturing in 2018								
Physical Contracts								
Receive variable/pay variable	Natural Gas	900,000	$ 4.03	$ 4.03	$ —	$ —	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for natural gas and $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2014 and December 31, 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.4 million of losses at December 31, 2014 and $0.1 million of gains at December 31, 2013 and collateral received.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2014 and 2013.

	At December 31, 2014						At December 31, 2013	
					Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Strike Price[2]	Market Price[2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 3.03	$ 3.8	$—	$ 1.7	$—
	NGL	2,254,500	$43.41	$26.09	$40.2	$—	$ 6.0	$—
	Crude Oil	730,000	$81.56	$56.78	$18.8	—	$ 1.8	$—
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 3.03	$ —	$—	$—	$(0.3)
	NGL	1,433,250	$45.74	$25.97	$ —	$(0.6)	$—	$(1.0)
	Crude Oil	730,000	$88.39	$56.78	$ —	$(0.4)	$—	$(1.9)
Puts (written)	Natural Gas	4,015,000	$ 3.90	$ 3.02	$ —	$(3.8)	$—	$—
Calls (purchased)	Natural Gas	1,277,500	$ 5.05	$ 3.03	$ —	$—	$—	$—
Portion of option contracts maturing in 2016								
Puts (purchased)	Natural Gas	1,647,000	$ 3.75	$ 3.46	$ 1.0	$—	$—	$—
	NGL	2,836,500	$39.24	$27.03	$39.3	$—	$—	$—
	Crude Oil	805,200	$75.91	$63.21	$14.7	$—	$—	$—
Calls (written)	Natural Gas	1,647,000	$ 4.98	$ 3.46	$ —	$(0.1)	$—	$—
	NGL	2,836,500	$45.14	$27.03	$ —	$(3.2)	$—	$—
	Crude Oil	805,200	$86.68	$63.34	$ —	$(2.7)	$—	$—
Puts (written)	Natural Gas	1,647,000	$ 3.75	$ 3.46	$ —	$(1.0)	$—	$—
Calls (purchased)	Natural Gas	1,647,000	$ 4.98	$ 3.46	$ 0.1	$—	$—	$—
Portion of option contracts maturing in 2017								
Puts (purchased)	NGL	365,000	$23.10	$22.79	$ 1.2	$—	$—	$—
	Crude Oil	365,000	$66.00	$66.97	$ 4.1	$—	$—	$—
Calls (written)	NGL	365,000	$26.15	$22.79	$ —	$(0.7)	$—	$—
	Crude Oil	365,000	$74.00	$66.97	$ —	$(3.3)	$—	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.

(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.

(3) The fair value is determined based on quoted market prices at December 31, 2014 and 2013, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.7 million of losses at December 31, 2014 and cash collateral received.

15. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws by the State of Texas that apply to entities organized as partnerships. Our income tax expense is based upon many but not all items included in net income.

We computed our income tax expense by applying a Texas state income tax rate to modified gross margin. Our Texas state income tax rate was 0.6% for the year ended December 31, 2014 and 0.5% for the years ended December 31, 2013 and 2012. Our income tax expense is summarized below:

	2014	2013	2012
		(in millions)	
Current state	$1.7	$0.8	$3.7
Deferred state	2.9	7.5	0.1
Total income tax expense	$4.6	$8.3	$3.8

Our effective tax rate is calculated by dividing the income tax expense by the pretax net book income or loss. The income base for calculating our state income tax expense is modified gross margin for Texas rather than pretax net book income or loss. As a result, this difference is the only reconciling item between the statutory and effective income tax rate. Our effective tax rate for the years ended December 31, 2014, 2013, and 2012, is as follows:

	2014	2013	2012
		(in millions)	
Income before income tax expense	$148.9	$62.2	$171.3
State income tax expense	$ 4.6	$ 8.3	$ 3.8
Effective income tax rate	3.1%	13.3%	2.1%

At December 31, 2014 and 2013, we included a current income tax payable of $1.5 million and $1.0 million, respectively in "Property and other taxes payable on our consolidated statements of financial position. In addition, at December 31, 2014 and 2013, we included a deferred income tax payable of $14.2 million and $11.1 million, respectively, in "Other long-term liabilities," on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting. Included in the $11.1 million as of December 31, 2013 is $6.0 million due to a new tax bill that went into effect in June 2013, as discussed below.

In June 2013, the Texas Legislature passed HB 500, which was subsequently signed into law. The most significant change in the law for us is that HB 500 allows a pipeline company that transports oil, gas, or other petroleum products owned by others to subtract as cost of goods sold, or COGS, its depreciation, operations and maintenance costs related to the services provided. Under the new law, we are allowed additional deductions against its income for Texas margin tax purposes. At December 31, 2013, we included approximately $6.0 million in our deferred income tax liability as a result of the revised tax law. On a go forward basis, our future effective tax rate in the State of Texas will be lower as a result of this law change.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment. The tax effects of significant temporary differences representing deferred tax assets and liabilities are as follows:

	December 31,	
	2014	2013
	(in millions)	
Net book basis of assets in excess of tax basis	$(14.0)	$(11.2)
Net book (gain) loss on derivatives not recognized for tax purposes	(0.2)	0.1
Net deferred tax liability	$(14.2)	$(11.1)

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ended December 31, 2013, 2012, and 2011.

Accounting for Uncertainty in Income Taxes

For the years ended December 31, 2014, 2013 and 2012, respectively, we have not recorded any amounts for uncertain tax positions.

16. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker, collectively comprised of our senior management, in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that are managed separately, since each business segment requires different operating strategies. We conduct our business through two distinct reporting segments:

- Gathering, Processing, and Transportation; and
- Logistics and Marketing.

The following tables present certain financial information relating to our business segments and corporate activities:

	As of and for the year ended December 31, 2014			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$2,611.2	$5,329.8	$ —	$7,941.0
Less: Intersegment revenue	1,963.9	82.8	—	2,046.7
Operating revenue	647.3	5,247.0	—	5,894.3
Cost of natural gas and natural gas liquids	27.1	5,118.8	—	5,145.9
Segment gross margin	620.2	128.2	—	748.4
Operating and maintenance	276.2	62.9	0.4	339.5
General and administrative	87.1	12.4	5.3	104.8
Depreciation and amortization	142.0	9.4	—	151.4
	505.3	84.7	5.7	595.7
Operating income (loss)	114.9	43.5	(5.7)	152.7
Other income	12.9[2]	—	—	12.9
Interest expense, net	—	—	16.7	16.7
Income (loss) before income tax expense	127.8	43.5	(22.4)	148.9
Income tax expense	—	—	4.6	4.6
Net income (loss)	127.8	43.5	(27.0)	144.3
Less: Net income attributable to:				
Noncontrolling interest	—	—	80.2	80.2
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 127.8	$ 43.5	$(107.2)	$ 64.1
Total assets	$5,205.4[3]	$ 460.3	$ 88.4	$5,754.1
Capital expenditures (excluding acquisitions)	$ 213.4	$ 16.6	$ 6.0	$ 236.0

(1) Corporate consists of interest expense, interest income, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Other income for our Gathering, Processing and Transportation segment includes our long-term equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

(3) Total assets for our Gathering, Processing and Transportation segment includes $380.6 million for our long-term equity investment in the Texas Express NGL system.

	As of and for the year ended December 31, 2013			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$2,689.8	$4,963.7	$ —	$7,653.5
Less: Intersegment revenue	1,960.8	99.1	—	2,059.9
Operating revenue	729.0	4,864.6	—	5,593.6
Cost of natural gas and natural gas liquids	157.6	4,779.5	—	4,937.1
Segment gross margin	571.4	85.1	—	656.5
Operating and maintenance	278.9	71.4	—	350.3
General and administrative	86.6	11.6	—	98.2
Depreciation and amortization	135.7	7.2	—	142.9
	501.2	90.2	—	591.4
Operating income (loss)	70.2	(5.1)	—	65.1
Other income (expense)	(1.5)[2]	—	0.3	(1.2)
Interest expense, net	—	—	1.7	1.7
Income (loss) before income tax expense	68.7	(5.1)	(1.4)	62.2
Income tax expense	—	—	8.3	8.3
Net income (loss)	68.7	(5.1)	(9.7)	53.9
Less: Net income attributable to:				
Noncontrolling interest	—	—	(0.6)	(0.6)
Net income (loss) attributable to general and limited partner ownership interests in Midcoast Energy Partners, L.P.	$ 68.7	$ (5.1)	$ (9.1)	$ 54.5
Total assets	$4,962.1[3]	$ 591.4	$482.9	$6,036.4
Capital expenditures (excluding acquisitions)	$ 233.8	$ 17.5	$ 18.8	$ 270.1

(1) Corporate consists of interest expense, interest income, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Other income (expense) for our Gathering, Processing, and Transportation segment includes our long-term equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

(3) Total assets for our Gathering, Processing and Transportation segment includes $371.3 million for our long-term equity investment in the Texas Express NGL system.

	As of and for the year ended December 31, 2012			
	Gathering, Processing and Transportation	Logistics and Marketing	Corporate[1]	Total
	(in millions)			
Total revenue	$2,716.9	$4,640.8	$ —	$7,357.7
Less: Intersegment revenue	1,898.9	100.9	—	1,999.8
Operating revenue	818.0	4,539.9	—	5,357.9
Cost of natural gas and natural gas liquids	131.2	4,452.9	—	4,584.1
Segment gross margin	686.8	87.0	—	773.8
Operating and maintenance	281.5	80.8	—	362.3
General and administrative	85.8	19.1	0.2	105.1
Depreciation and amortization	128.0	7.0	—	135.0
	495.3	106.9	0.2	602.4
Operating income (loss)	191.5	(19.9)	(0.2)	171.4
Other expense	—	—	(0.1)	(0.1)
Income (loss) before income tax expense	191.5	(19.9)	(0.3)	171.3
Income tax expense	—	—	3.8	3.8
Net income (loss)	$ 191.5	$ (19.9)	$ (4.1)	$ 167.5
Total assets	$4,609.0[2]	$1,011.8	$46.6	$5,667.4
Capital expenditures (excluding acquisitions)	$ 443.6	$ 9.0	$ —	$ 452.6

(1) Corporate consists of interest expense, interest income, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Total assets for our Gathering, Processing and Transportation segment includes $183.7 million for our long-term equity investment in the Texas Express NGL system.

Our revenue is derived from a wide customer base. No revenues from transactions with a single external customer amounted to 10% or more of our total consolidated revenues for the years ended December 31, 2014, 2013, and 2012.

17. SUPPLEMENTAL CASH FLOWS INFORMATION

	For the year ended December 31,		
	2014	2013	2012
	(in millions)		
Cash paid during the year for:			
Interest (net of capitalization)[1]	$12.0	$20.2	$11.9
Income taxes	$ 1.5	$ 2.5	$ 2.8

(1) Prior to the Offering, the interest cost we recognized was an allocation of EEP's cost. In connection with the closing of the Offering, the Partnership, Midcoast Operating, and their material domestic subsidiaries, entered into the Credit Agreement to establish their own committed senior revolving credit facility.

In the “Cash used in investing activities” section of the consolidated statements of cash flows, we exclude changes that did not affect cash. The following is a reconciliation of additions to property, plant and equipment to total capital expenditures (excluding “Investment in joint venture”):

	For the year ended December 31,		
	2014	2013	2012
		(in millions)	
Additions to property, plant and equipment	$237.7	$273.4	$451.7
Increase (decrease) in construction payables	(1.7)	(3.3)	0.9
Total capital expenditures (excluding “Investment in joint venture”)	$236.0	$270.1	$452.6

18. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Discontinued Operations

In April 2014, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2014-08 that changes the criteria and requires expanded disclosures for reporting discontinued operations. This accounting update is effective for annual and interim periods beginning after December 15, 2014, and is to be applied prospectively. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

Revenues from Contracts with Customers

In May 2014, the FASB issued Accounting Standards Update No. 2014-09 that outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis. We are currently evaluating which transition approach we will apply and the impact that this pronouncement will have on our consolidated financial statements.

Going Concern Uncertainties

In August 2014, the FASB issued Accounting Standards Update No. 2014-15 which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of an entity’s ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity’s ability to continue as a going concern. This accounting update is effective for annual and interim periods beginning on or after December 15, 2016, with early adoption permitted. We do not expect that the adoption of this pronouncement will have a material impact on our consolidated financial statements.

19. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second	Third	Fourth	Total
	(in millions, except per unit amounts)				
2014 Quarters					
Operating revenue	$1,646.9	$1,396.8	$1,399.4	$1,451.2	$5,894.3
Operating expense	$1,634.6	$1,402.4	$1,384.2	$1,320.4	$5,741.6
Operating income (loss)	$ 12.3	$ (5.6)	$ 15.2	$ 130.8	$ 152.7
Net income (loss)	$ 6.7	$ (6.8)	$ 16.0	$ 128.4	$ 144.3
Net income (loss) attributable to noncontrolling interest	$ 6.3	$ (2.2)	$ 9.7	$ 66.4	$ 80.2
Net income (loss) attributable to limited partner ownership interests	$ 0.4	$ (4.5)	$ 6.2	$ 60.7	$ 62.8
Net income (loss) per limited partner unit	$ 0.01	$ (0.09)	$ 0.14	$ 1.34	$ 1.39
2013 Quarters					
Operating revenue	$1,370.3	$1,299.1	$1,380.9	$1,543.3	$5,593.6
Operating expense	$1,339.2	$1,262.9	$1,393.8	$1,532.6	$5,528.5
Operating income (loss)	$ 31.1	$ 36.2	$ (12.9)	$ 10.7	$ 65.1
Net income (loss)	$ 30.7	$ 28.5	$ (13.5)	$ 8.2	$ 53.9
Net income (loss) attributable to noncontrolling interest(1)	$ 18.7	$ 17.4	$ (8.3)	$ 5.9	$ 33.7
Net income (loss) attributable to limited partner ownership interests(1)	$ 11.8	$ 10.8	$ (5.1)	$ 2.2	$ 19.7
Net income (loss) per limited partner unit(1)	$ 0.44	$ 0.41	$ (0.19)	$ 0.06	$ 0.68

(1) Represents calculation retrospectively reflecting the affiliate capitalization of MEP consisting of 4.1 million MEP Class A common units, 22.6 million MEP subordinated units and MEP general partner interest upon the transfer of a controlling ownership, including limited partner and general partner interest, in Midcoast Operating. The noncontrolling interest reflects the 61% retained by EEP.

20. SUBSEQUENT EVENTS

Eaglebine Acquisition

On February 9, 2015, we announced an agreement with New Gulf Resources, LLC, or NGR, to purchase NGR's midstream business in Leon, Madison and Grimes Counties, Texas for $85.0 million. The acquisition consists of a natural gas gathering system that is currently in operation moving equity and third party production.

Distribution to Partners

On January 28, 2015, the board of directors of our General Partner, declared a cash distribution payable to our partners on February 13, 2015. The distribution was paid to unitholders of record as of February 6, 2015, of our available cash of $15.8 million at December 31, 2014, or $0.3425 per limited partner unit. We paid $7.3 million to the holders of our public Class A common units, while $8.5 million in the aggregate was paid to EEP with respect to its Class A common units, subordinated units and general partner interest.

Midcoast Operating Distribution

On January 28, 2015, the general partner of Midcoast Operating declared a cash distribution by Midcoast Operating payable to its partners of record as of February 6, 2015. Midcoast Operating paid $21.1 million to us and $19.8 million to EEP on February 13, 2015.

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

None.

Item 9A. Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in the reports that we file or submit under the Exchange Act within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2014. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Annual Report on Internal Control Over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f).

The Partnership's internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers, and effected by the board of directors of our General Partner, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership's financial statements for external purposes in accordance with generally accepted accounting principles.

The Partnership's internal control over financial reporting includes policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect transactions and dispositions of assets of the Partnership;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with the authorizations of the Partnership's management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, the Partnership's internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with our policies or procedures may deteriorate.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2014, with the participation of our principal executive and principal financial officers, based on the framework established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2014.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in Item 8. *Financial Statements and Supplementary Data*.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended December 31, 2014.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

We are a limited partnership and have no officers or directors of our own. Set forth below is certain information concerning the directors and executive officers of our General Partner. Directors are elected by the sole member of our General Partner and hold office until their successors have been elected or qualified or until their earlier death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors. The following table shows information for the directors and executive officers of Midcoast Holdings.

Name	Age	Position
Dan A. Westbrook	62	Director and Chairman of the Board
John A. Crum	62	Director
J. Herbert England	68	Director
C. Gregory Harper	50	Director and President
James G. Ivey	63	Director
Mark A. Maki	50	Director and Senior Vice President
Edmund P. Segner III	61	Director
Janet L. Coy	57	Vice President—Natural Gas Marketing
John A. Loiacono	52	Vice President—Commercial Activities
Stephen J. Neyland	47	Vice President—Finance
Kerry C. Puckett	53	Vice President—Engineering and Operations, Gathering & Processing
Noor S. Kaissi	42	Controller
E. Chris Kaitson	58	Vice President—Law and Assistant Corporate Secretary
Byron C. Neiles	49	Vice President—Major Projects
Jonathan N. Rose	47	Treasurer
Allan M. Schneider	56	Vice President—Regulated Engineering and Operations
David A. Weathers	60	Vice President—Business Development U.S. Midstream
Thomas J. Zimmerman	61	Vice President—Integrity and Environment, Health & Safety

DIRECTORS AND NAMED EXECUTIVE OFFICERS

Dan A. Westbrook

Dan A. Westbrook was appointed Chairman of the Board and elected as a director of our General Partner in October 2013 and also serves on the Audit, Finance and Risk Committee. Mr. Westbrook has also served as a director of EEP's general partner and Enbridge Management since October 2007, and serves on the Audit, Finance & Risk Committee of both companies, as well as serving on Special Committees of Enbridge Management. Since 2008, he has also served on the board of the Carrie Tingley Hospital Foundation in Albuquerque, New Mexico. During 2013, Mr. Westbrook was named a director of SandRidge Energy, Inc. From 2001 to 2005, Mr. Westbrook served as president of BP China Gas, Power & Upstream and as vice-chairman of the board of directors of Dapeng LNG, a Sino joint venture between BP subsidiary CNOOC Gas & Power Ltd. and other Chinese companies. He held executive positions with BP in Argentina, Houston, Russia, Chicago and the Netherlands before retiring from the company in January 2006. From August 2002 to June 2004, Mr. Westbrook served as director and chairman of the finance committee of the International School of Beijing. He is a former director of Ivanhoe Mines, now known as Turquoise Hill Resources Ltd., an international mining company, Synenco Energy Inc., a Calgary-based oil sands company, and Knowledge Systems Inc., a privately-held U.S. company that provides software and consultant services to the oil and gas industry.

Through his long career in the petroleum exploration and production industry, including his other public company directorships and previous service as President of BP China, Mr. Westbrook provides the board of directors with extensive industry experience, leadership skills, international and petroleum development experience, as well as knowledge of our business environment.

John A. Crum

John A. Crum was appointed a director of our General Partner on February 10, 2014 and also was appointed to serve on the Audit, Finance and Risk Committee. On March 31, 2014, Mr. Crum resigned as Midstates Petroleum Company, Inc.'s Chairman, President and Chief Executive Officer, positions he had held since 2011. He also continues to serve on the board of directors of Coskata, Inc. a private biofuel technology company, since August 2012. From 1995 to 2011, Mr. Crum served in several roles for various Apache Corporation divisions, including Co-Chief Operating Officer and President, North America from 2009 to 2011. Some previous positions held by Mr. Crum include Vice President of Engineering and Operations of Aquila Energy Corporation from 1993 to 1995 and District Manager and Regional Manager for Pacific Enterprises Oil Company from 1986 to 1993.

Mr. Crum brings to the board almost forty years of experience in the energy industry in a variety of engineering and management roles, including leadership through an initial public offering.

J. Herbert England

J. Herbert England was elected a director of our General Partner in October 2013 and serves as the Chairman of the Audit Finance & Risk Committee of our General Partner. Mr. England has also served as a director of each of EEP's general partner and Enbridge Management since July 2012 and serves as the Chairman of the Audit, Finance & Risk Committee of both companies. In addition, Mr. England serves on the Enbridge board of directors for whom he also is Chairman of the Audit, Finance & Risk Committee, and on the board of directors of FuelCell Energy, Inc. He has been Chair & Chief Executive Officer of Stahlman-England Irrigation Inc., a contracting company in southwest Florida, since 2000. From 1993 to 1997, Mr. England was the Chair, President & Chief Executive Officer of Sweet Ripe Drinks Ltd., a fruit beverage manufacturing company. Prior to 1993, Mr. England held various executive positions with John Labatt Limited, a brewing company, and its operating companies, Catelli Inc., a food manufacturing company, and Johanna Dairies Inc., a dairy company.

Mr. England brings to the board of directors a wide range of financial executive experience because of his previous positions, as well as his service with other public company audit committees.

C. Gregory Harper

C. Gregory Harper was appointed to the board of directors of our General Partner on January 30, 2014 and appointed President effective December 31, 2014. He has been the principal executive officer of our General Partner since February 28, 2014. Mr. Harper has also served as a director of each of EEP's general partner and Enbridge Management since January 30, 2014 and Executive Vice President – Gas Pipelines & Processing since April 30, 2014. Mr. Harper also was appointed as President, Gas Pipelines and Processing for Enbridge effective January 30, 2014. He is also on the board of directors of Sprague Operating Resources LLC since October 2013. Mr. Harper joins Midcoast Holdings and its affiliates from Southwestern Energy Company, where he held the position of Senior Vice President, Midstream since 2013. Prior to joining Southwestern Energy Company, Mr. Harper served CenterPoint Energy, Inc. as Senior Vice President and Group President, Pipelines and Field Services since December 2008. Before joining CenterPoint Energy in 2008, Mr. Harper served as President, Chief Executive Officer and as a Director of Spectra Energy Partners, LP from March 2007 to December 2008. From January 2007 to March 2007, Mr. Harper served as Group Vice President of Spectra Energy Corp., and was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper was Senior Vice President of Energy Marketing and Management for Duke Energy North America from January 2003 until January 2004 and Vice President of Business Development for Duke Energy Gas Transmission and Vice President of East Tennessee Natural Gas, LLC from March 2002 until January 2003. He served on the Board of Directors and as Chairman of the Interstate Natural Gas Association of America from 2013.

Mr. Harper brings to the board insight and in-depth knowledge of our industry. He also provides leadership skills, pipeline operations and management expertise and knowledge of our local community and business environment, which he has gained through his long career in the oil and gas industry.

James G. Ivey

James G. Ivey was appointed a director of our General Partner on February 10, 2014 and also was appointed to serve on the Audit, Finance and Risk Committee. Mr. Ivey currently co-heads Pintail Energy, an exploration and production company he co-founded in 2014. Mr. Ivey currently serves on the board of directors of privately held independent power producing, National Energy & Gas Transmission, Inc. since. His prior experience includes serving Milagro Exploration from 2009 to 2012 in the role of Executive Vice President and Chief Financial Officer (2009-2010) and then President and Chief Executive Officer (2010-2012). From 2006 to 2008, Mr. Ivey was Executive Vice President and Chief Financial Officer of Cobalt International Energy. From 2004 to 2006, Mr. Ivey served Markwest Hydrocarbon as Senior Vice President and Chief Financial Officer. His previous background includes serving as the Corporate Treasurer for each of Williams Companies (1995-2004) and Arkla Gas (1982-1995) as well as other financial and engineering positions with Conoco and Fluor from 1973 to 1981.

Mr. Ivey brings to the board over forty years of experience in the oil and gas industry in the exploration and production areas, as well as Master Limited Partnership, or MLP, midstream experience in engineering, finance and corporate governance.

Mark A. Maki

Mark A. Maki was appointed Senior Vice President of our General Partner in February 2014, and he has served as a director of our General Partner since May 2013. Previously he served as Principal Executive Officer from October 2013 until February 2014. Mr. Maki previously served as President of our General Partner from May 2013 to October 2013. He was appointed President and Principal Executive Officer of EEP's general partner and Enbridge Management on January 30, 2014 and has served both companies as a director since October 2010. Mr. Maki previously served as President of Enbridge Management and Senior Vice President of EEP's general partner from October 2010. He also served Enbridge in the functional title of Acting President, Gas Pipelines during 2013. Mr. Maki previously served as Vice President—Finance of EEP's general partner and Enbridge Management from July 2002 to October 2010. Prior to that time, Mr. Maki served as Controller of EEP's general partner and Enbridge Management from June 2001, and prior to that, as Controller of Enbridge Pipelines from September 1999.

Mr. Maki joined Enbridge in 1986 and progressed through a series of accounting and financial roles of increasing responsibility during his tenure in the United States and Canada. Through his broad range of domestic and Canadian experience in the pipeline industry, Mr. Maki provides the board of directors with financial expertise, leadership skills in our industry and knowledge of our local community and business environment.

Edmund P. Segner III

Edmund P. Segner III was appointed a director of our General Partner on February 10, 2014. Mr. Segner is currently a professor in the Department of Civil and Environmental Engineering at Rice University and serves on the boards of directors of three other companies and audit committees, as follows: Bill Barrett Corp., an oil and gas exploration and production company, since August 2009; Exterran GP LLC, the general partner of Exterran Partners, L.P., an MLP which provides contract operations since May 2009 in; and Laredo Petroleum Holdings, Inc., a Permian oil and gas exploration and development company since August 2011. Mr. Segner retired from EOG Resources, Inc. in 2008. He had held several offices at EOG during his tenure from 1997 to 2008 including President, Chief of Staff and Director and principal financial officer. Formerly, from 1988 to early 1998, Mr. Segner held several positions with Enron Corporation, including Vice President, Senior Vice President and Executive Vice President. Previously, Mr. Segner also served on the boards of Seahawk Drilling from 2009 to 2011 and of Universal Compression Holdings from 2000-2002. He has also served as a member of the board or as a trustee for several nonprofit organizations.

Mr. Segner brings to the board his broad experience in management, his experience with MLPs and his financial expertise as well as his audit committee experience.

Janet L. Coy

Janet L. Coy was appointed Vice President—Natural Gas Marketing of our General Partner in May 2013. Ms. Coy also served as Vice President—Natural Gas Marketing of EEP's general partner and Enbridge Management from October 2010 to April 2014. Ms. Coy previously served as President of the Natural Gas Marketing subsidiaries of Enbridge Management and EEP's general partner since the acquisition of Midcoast Energy Resources, Inc. in May 2001 and continues to serve in that capacity.

John A. Loiacono

John A. Loiacono was appointed Vice President—Commercial Activities of our General Partner in May 2013. Mr. Loiacono also served as Vice President—Commercial Activities of EEP's general partner and Enbridge Management from July 2006 to April 2014. Prior to that, he was Director of Commercial Activities for our General Partner and Enbridge Management from April 2003 and commenced employment with Midcoast Energy Resources, Inc. in February 2000 as an Asset Optimizer until it was acquired by Enbridge in May 2001.

Stephen J. Neyland

Stephen J. Neyland was appointed Vice President—Finance of our General Partner in May 2013. Mr. Neyland has served as Vice President—Finance of EEP's general partner and Enbridge Management since October 2010. Mr. Neyland was previously Controller of EEP's general partner and Enbridge Management effective September 2006. Prior to his appointment, he served as Controller—Natural Gas from January 2005, Assistant Controller from May 2004 to January 2005 and in other managerial roles in finance and accounting from December 2001 to May 2004. Prior to that time, Mr. Neyland was Controller of Koch Midstream Services from 1999 to 2001.

Kerry C. Puckett

Kerry C. Puckett was appointed Vice President—Engineering and Operations, Gathering & Processing of our General Partner in May 2013. Mr. Puckett also served as Vice President—Engineering and Operations, Gathering & Processing of EEP's general partner and Enbridge Management from October 2007 to April 2014. Prior to his appointment, he served as General Manager of Engineering and Operations from 2004 and Manager of Operations from 2002 to 2004. Prior to that time, he served as Manager of Business Development for Sid Richardson Energy Services Company.

OTHER EXECUTIVE OFFICERS

Noor S. Kaissi was appointed Controller of our General Partner in July 2013. Ms. Kaissi has also served EEP's general partner and Enbridge Management as Controller since July 2013. Prior to her appointment as Controller for these companies, Ms. Kaissi served as Chief Auditor and in other managerial roles of EEP's general partner and Enbridge Management and more recently with our General Partner with responsibility for financial accounting, internal audit and controls from June 2005.

E. Chris Kaitson was appointed Vice President—Law and Assistant Corporate Secretary of our General Partner in May 2013. Mr. Kaitson has served as Vice President—Law and Assistant Corporate Secretary of EEP's general partner and Enbridge Management since May 2007. He also currently serves as Deputy General Counsel of Enbridge. Prior to that, he was Assistant General Counsel and Assistant Secretary of EEP's general partner and Enbridge Management from July 2004. He served as Corporate Secretary of EEP's general partner and Enbridge Management from October 2001 to July 2004. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until it was acquired by Enbridge in May 2001.

Byron C. Neiles was appointed Vice President—Major Projects of our General Partner in May 2013. He was elected Senior Vice President—Major Projects of EEP's general partner and Enbridge Management in April

2013. Previously, Mr. Neiles served EEP's general partner and Enbridge Management as Vice President—Major Projects from October 2010. Additionally, Mr. Neiles has served Enbridge as Senior Vice President—Major Projects since November 2011 and previously served Enbridge as Vice President in the Major Projects division since April 2008, prior to which he was Vice President of Enbridge Gas Distribution from 2003 to 2008. Mr. Neiles joined Enbridge in 1994.

Jonathan N. Rose was appointed Treasurer of our General Partner in March 2014. Mr. Rose was also appointed Treasurer of EEP's general partner and Enbridge Management in March 2014. Additionally, Mr. Rose serves Enbridge in the role of Director, Treasury since 2014. Mr. Rose's prior roles with Enbridge include Director, Business Development of Enbridge Pipelines Inc. from April 2010 to March 2014 and Treasurer of EEP's general partner and Enbridge Management from January 2008 to April 2010. He was previously Assistant Treasurer of EEP's general partner and Enbridge Management from July 2005 to December 2008. Mr. Rose was also Director, Finance of Enbridge, a position he held from October 2007 to 2010, prior to which he was Manager, Finance from 2004 to December 2008. Prior to that Mr. Rose was a Vice President with Citigroup Global Corporate and Investment Bank from 2001 to 2004.

Allan M. Schneider was appointed Vice President—Regulated Engineering and Operations of our General Partner in May 2013. Mr. Schneider has served as Vice President—Regulated Engineering and Operations of EEP's general partner and Enbridge Management since October 2007. Prior to his appointment, he served as Director of Engineering and Operations for Regulated & Offshore and Director of Engineering Services from January 2005. Prior to that, Mr. Schneider was Vice President of Engineering and Operations for Shell Gas Transmission, L.L.C. from December 2000.

David A. Weathers was appointed Vice President—Business Development U.S. Midstream of our General Partner in July 2014. Previously, Mr. Weathers was Sr. Director, Midstream at Southwestern Energy from October 2013 to July 2014. Prior to joining Southwestern Energy, he was Director and Sr. Director, US Gas Assets of NextEra Energy from July 2008 to October 2013. Before joining NextEra, Mr. Weathers served as General Manager, Business Development for Spectra Energy and various other positions spanning over 30 years with Spectra's predecessor companies.

Tom Zimmerman was appointed Vice President, Integrity and Environment, Health & Safety of our General Partner in May 2014. He is responsible for supporting safe and reliable operations for the company and its subsidiaries. From January 2014 to May 2014, Mr. Zimmerman served Enbridge as Vice President, Integrity—Gas Pipelines for the Gas Transportation department. From July 2012 to January 2014 he was Director, Research, Development & Innovation for Enbridge prior to which he was Director, Operations Service since February 2011. From June 2010 to February 2011 he was Program Manager, System Integrity and from August 2009 to June 2010 he was Manager, Programs & Technical Services. He joined Enbridge in the Liquids Pipelines division in March 2006 as a pipeline integrity engineering specialist. Prior to joining Enbridge, he spent twenty-one years at C-FER Technologies, in Edmonton, Alberta, where he was involved in engineering research and development activities.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our directors, executive officers and 10% beneficial owners to file with the SEC reports of ownership and changes in ownership of our equity securities and to furnish us with copies of all reports filed. Based on our review of the Section 16(a) filings that have been received by us and the written representations made by our directors and executive officers, we believe that all filings required to be made under Section 16(a) during 2014 were timely made except for one late Form 3 filed on behalf of James G. Ivey made on February 21, 2014, which filing had been submitted and suspended, but not refiled on time.

GOVERNANCE MATTERS

We are a "controlled company," as that term is used in NYSE Rule 303A, because all of our voting units are owned by our General Partner. Because we are a controlled company, the NYSE listing standards do not require that we or our General Partner have a majority of independent directors or a nominating or compensation committee of our General Partner's board of directors.

The NYSE listing standards require our principal executive officer to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. Accordingly, this certification was provided as required to the NYSE on July 11, 2014.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

We have adopted a Code of Ethics applicable to our General Partner's senior officers, including the principal executive officer, principal financial officer and principal accounting officer. A copy of the Code of Ethics for Senior Financial Officers is available on our website at *www.midcoastpartners.com*. We post on our website any amendments to or waivers of our Code of Ethics for Senior Officers and we intend to satisfy any disclosure requirements that may arise under Form 8-K relating to this information through such postings. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how our board of directors should function and its position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at *www.midcoastpartners.com*. We post on our website any amendments to our Corporate Governance Guidelines, and we intend to satisfy any disclosure requirements that may arise under Form 8-K relating to these amendments through such postings. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

We also have a Statement of Business Conduct applicable to all of our employees, officers and directors. A copy of the Statement of Business Conduct is available on our website at *www.midcoastpartners.com*. We post on our website any amendments to or waivers of our Statement of Business Conduct, and we intend to satisfy any disclosure requirements that may arise under Form 8-K relating to this information through such postings. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

AUDIT, FINANCE & RISK COMMITTEE

MEP's General Partner has an Audit, Finance & Risk Committee, referred to as the "Audit Committee," comprised of four board members who are independent as the term is used in Section 10A of the Exchange Act. None of these members are relying upon any exemptions from the foregoing independence requirements. The members of the Audit Committee are John A. Crum, J. Herbert England, James G. Ivey and Dan A. Westbrook. J. Herbert England is chairman of the Audit Committee. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the report of the independent registered public accounting firm. The Audit Committee also reviews the scope and quality, including the independence and objectivity, of the independent and internal auditors and the fees paid for both audit and non-audit work and makes recommendations concerning audit matters, including the engagement of the independent auditors, to the Board of Directors.

The charter of the Audit Committee is available on our website at www.midcoastpartners.com. The charter of the Audit Committee complies with the listing standards of the NYSE currently applicable to us. This material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

The General Partner's Board of Directors has determined that J. Herbert England and James G. Ivey each qualify as "audit committee financial experts" as defined in Item 407(d)(5)(ii) of Regulation S-K. Each of the members of the Audit Committee is independent as defined by Section 303A of the listing standards of the NYSE.

Mr. England serves on the audit committees of the General Partner and the general partner of Enbridge Energy Partners, L.P., Enbridge Management, FuelCell Energy, Inc., and Enbridge Inc. In compliance with the provisions of the Audit Committee Charter, the boards of directors of the General Partner and of Enbridge Management and the general partner of Enbridge Energy Partners, L.P. have determined that Mr. England's simultaneous service on such audit committees does not impair his ability to effectively serve on the Audit Committee.

The General Partner's Audit Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our Audit Committee may do so by writing to the Chairman, Audit Committee, c/o Midcoast Holdings, L.L.C., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of the General Partner meet at regularly scheduled executive sessions without management. Dan A. Westbrook serves as the presiding director at those executive sessions. Persons wishing to communicate with the Company's independent directors may do so by writing to the Chairman, Board of Directors, Midcoast Holdings, L.L.C., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

General

We are a MLP and do not directly employ any employees, nor do we have executive officers or directors. We are managed by our General Partner and the Named Executive Officers, or NEOs, who are executive officers of our General Partner. Our General Partner is wholly owned and controlled by EEP, which is also a MLP and does not directly employ any employees. We entered into an intercorporate services agreement with EEP, which is managed and controlled by Enbridge Management, to provide us with managerial, administrative and operational services. EEP's general partner, Enbridge Management and Enbridge, through its affiliates, provide managerial, administrative, operational and director services to EEP pursuant to service agreements among them and EEP. Pursuant to our intercorporate services agreement, we reimburse EEP for an allocated portion of the costs of these services, which costs include a portion of the compensation of the NEOs.

The board of directors of our General Partner does not have compensation committees, nor does it have responsibility for approving the elements of compensation for the NEOs presented in the tables following this discussion. The board of directors of our General Partner, as part of our annual budgeting process, however, do have responsibility for evaluating and determining the reasonableness of our overall budget. The budget includes compensation amounts to be allocated to us for managerial, administrative, operational and director support to be provided by our General Partner, EEP and its affiliates pursuant to the intercorporate service agreement mentioned above. The budgeted amount of total compensation includes the portion of the compensation of the NEOs that will be allocated to us and is discussed in more detail below.

Since we do not have direct employees or directors, and our General Partner does not have responsibility for approving the elements of compensation for the NEOs, we and our General Partner do not have compensation policies. The compensation policies and philosophy of Enbridge govern the types and amounts of compensation of each of the NEOs. The NEOs at December 31, 2014 were:

- C. Gregory Harper, President (Principal Executive Officer) and Director;
- Mark A. Maki—Senior Vice President (*Former Principal Executive Officer*) and Director;
- Stephen J. Neyland, Vice President—Finance (Principal Financial Officer);
- John A. Loiacono, Vice President—Commercial Activities;
- Kerry C. Puckett, Vice President—Engineering and Operations, Gathering and Processing;
- Janet L. Coy, Vice President—Natural Gas Marketing; and
- Terrance L. McGill—Former President and Chief Commercial Officer *(retired)*.

Mr. Harper is also an executive officer of Enbridge and serves as President, Gas Pipelines & Processing of Enbridge. Since Mr. Harper is also an executive officer of Enbridge, the Human Resources and Compensation Committee of the board of directors of Enbridge, or the HRC Committee, approves the elements of compensation for him based on the recommendation of the President & Chief Executive Officer of Enbridge considering his position within Enbridge on an enterprise-wide basis. Furthermore, Messrs. Harper, Maki, and Neyland are also officers of EEP's general partner and Enbridge Management.

Compensation of our NEOs, with the exception of Mr. Harper (noted above), is determined as part of an Enbridge enterprise-wide review process. Each business unit develops a salary increase budget recommendation, in consultation with the Enbridge corporate compensation department, based on a competitive analysis of the labor market for that business unit. These recommendations are presented, in summary and on a business unit basis, to the Human Resources and Compensation Committee of the board of directors of Enbridge, or the HRC Committee, for approval. Individual salary increases are implemented after the HRC Committee approves the overall budget. Compensation adjustments for the remaining NEOs are recommended by their supervisors and reviewed by the Executive Leadership Team of Enbridge, including the President & Chief Executive Officer of Enbridge. Enbridge's President & Chief Executive Officer approves the individual salary increase recommendations, on an enterprise-wide basis, to ensure that compensation expense is within the budget approved by the HRC Committee. Each of the NEOs provides services to other affiliates of Enbridge and, therefore, compensation is determined on the basis of overall performance with respect to Enbridge and all of its affiliates and not solely based on performance with respect to us.

We are a partnership and not a corporation for United States federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Internal Revenue Code §162(m). In addition, we are not the employer for any of the NEOs.

The board of directors of Enbridge implemented an Incentive Compensation Clawback Policy that enables it to recover, from current and former executives, certain incentive compensation amounts that were awarded or paid to such individuals based upon the achievement of financial results that are subsequently materially restated or corrected, in whole or in part, if such individuals engaged in fraud or willful misconduct that resulted in the need for such restatement or correction and it is determined that the incentive compensation paid to the individuals would have been lower based on the restated or corrected results.

For a more detailed discussion of the compensation policies and philosophy of Enbridge, we refer you to a discussion of those items as set forth in the Executive Compensation section of the Enbridge Management

Information Circular, or MIC, on the Enbridge website at www.enbridge.com. The Enbridge MIC is produced by Enbridge pursuant to Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Exchange Act. We refer to the MIC to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our General Partner.

Elements of Compensation

The HRC Committee sets the compensation philosophy of Enbridge, which is approved by the Enbridge board of directors. Enbridge has a pay-for-performance philosophy and programs that are designed to be aligned with its interests, on an enterprise-wide basis, as well as the interests of its shareholders. A significant portion of total direct compensation of Enbridge's senior management is dependent on actual performance measured against short, medium and long-term performance goals of Enbridge, on an enterprise-wide basis, which are approved by the HRC Committee. As business units of Enbridge, we and EEP contribute to its overall growth, earnings and attainment of performance goals.

The elements of total compensation in 2014 for senior management of Enbridge, which includes Mr. Harper, are:

- Base Salary—to provide a fixed level of compensation for performing day-to-day responsibilities, while balancing the individual's role and competency, market conditions and issues of attraction and retention.
- Short-term incentive—to provide a competitive, performance cash award based on pre-determined corporate, business unit and individual goals that measure the execution of the business strategy over a one-year period.
- Medium-term and long-term incentives—to recognize contributions and provide competitive, compensation comprised of performance stock units, restricted stock units, performance stock options and incentive stock options that are tied to the share price of Enbridge common shares and other financial measures, and are considered at-risk to motivate performance over the medium and long term.
- Pension plan—to provide a competitive retirement benefit.
- Savings plan—to promote ownership of Enbridge common shares and to provide the opportunity to save additional funds for retirement or other financial goals.
- Perquisites—to provide a competitive allowance to offset expenses largely related to the executive's role.
- Benefits—to provide security pertaining to health and welfare risks in a flexible manner to meet individual needs.
- Employment agreements—to provide specific total compensation terms in situations of involuntary termination or constructive dismissal.

The elements of compensation for the remaining NEOs are similar to those described above, except that none have an employment agreement, and they are not eligible for Enbridge performance stock options. The HRC Committee makes determinations as to whether the enterprise-wide performance goals have been achieved, approves business unit results and makes adjustments as necessary to more accurately reflect whether those goals have been met or exceeded. For example, the HRC Committee may determine to disregard a non-cash gain or loss reflected in our results of operations that resulted from mark-to-market accounting for our derivative activities in determining whether certain goals have been met.

Base Salary

Base salary for the NEOs reflects a balance of market conditions, role, individual competency and attraction and retention considerations and takes into account compensation practices at peer companies of Enbridge. Increases in base pay for all NEOs are based primarily on competitive considerations.

Short-Term Incentive Plan

The Enbridge short-term incentive plan, or STIP, is designed to provide incentive for, and to reward, the achievement of goals that are aligned with the Enbridge annual business plan. The target short-term incentive reflects the level of responsibility associated with the role and competitive practice and is expressed as a percentage of base salary. Actual incentive awards can range from zero to two times the target. Awards under the plan are based on performance relative to goals achieved at the Enbridge corporate level, business unit level and individual level. Performance relative to goals in each of these areas is reflected on a scale of zero to two; zero indicates performance was below threshold levels, one indicates that goals were achieved and two indicates that performance was exceptional. Ms. Coy is the only NEO to have her performance reflected on a scale of zero to three; zero indicates performance was below threshold levels, one indicates that goals were achieved, two indicates that performance goals were exceeded and three indicates that performance was exceptional.

The following is a summary for 2014 of the incentive targets, payout range, and relative weightings between the Enbridge corporate, business unit and individual performance:

			Relative Weighting		
	Target STIP%[1]	Pay Out Range	Corporate	Business Unit	Individual
C. Gregory Harper *President (and Principal Executive Officer) and Director*	60%	0-120%	25%	50%	25%
Mark A. Maki *Senior Vice President (Former Principal Executive Officer) and Director*	40%	0-80%	25%	50%	25%
Stephen J. Neyland *Vice President—Finance (and Principal Financial Officer)*	35%	0-70%	25%	50%	25%
John A. Loiacono *Vice President—Commercial Activities*	35%	0-70%	25%	50%	25%
Kerry C. Puckett *Vice President—Engineering and Operations, Gathering and Processing*	35%	0-70%	25%	50%	25%
Janet L. Coy *Vice President—Natural Gas Marketing*	35%	0-105%	25%	50%	25%
Terrance L. McGill *(Former President and Chief Commercial Officer)*	40%	0-80%	25%	50%	25%

(1) All values are expressed as percentages of base salary.

The overall performance multiplier and STIP are calculated as follows:

Performance multiplier		STIP	
	Corporate target incentive opportunity x (0-2)		Base Salary $
+	Business unit target incentive opportunity x (0-2)	x	Target STIP %
+	Individual target incentive opportunity x (0-2)	x	Overall performance multiplier (0-2)
=	Overall performance multiplier (0-2)	=	$ Short term incentive award

Enbridge Corporate Performance

Corporate performance is measured by adjusted earnings per share, or EPS. This is a metric that focuses on return to shareholders and is aligned with how investors and security analysts assess Enbridge's performance on an annual basis. For short-term incentive purposes, adjusted earnings also exclude the impact of certain long-term financing activities on earnings.

The adjusted EPS metric represents a significant component of the named executives' short-term incentive award at 25%. Enbridge's 2014 EPS guidance range was $1.84 Canadian Dollars, or CAD, to $2.04 CAD, as approved by the Enbridge board of directors prior to the start of 2014. Actual performance was $1.90 CAD. Adjustments are made to ensure the result is a fair reflection of performance. Approximately $420.0 million CAD was adjusted out of the calculation, including mark-to-market gains/losses and tax on intercompany gains and sales. The corporate multiplier ranges from 0 to 2.0, with 1.0 meaning that the performance measure was met. Adjusting out the impact of certain long-term financing activities (noted above), in 2014, Enbridge had an adjusted EPS of $1.91 CAD (verses $1.90 CAD per share) and a short-term corporate multiplier of 0.70 out of 2.0.

Enbridge Business Unit Performance

Business unit performance measures vary among the NEOs to reflect the annual business plans and operations for which each NEO is accountable. Performance is measured against targets that are established at the beginning of the year. The detailed business unit performance measures for each of the NEOs are set forth in the tables which follow.

The business performance measure for each NEO is designed to reflect their multiple responsibilities at Enbridge. For 2014, Mr. Harper's performance measure is calculated at 50% Gas Pipelines and Processing–Enbridge business unit, or GPP EI, and 50% for the Gas Pipelines and Processing–Midcoast Operating business unit, or GPP MEP, resulting in a business unit multiplier of 1.24 out of 2.0. For 2014, Mr. Maki's performance measure is calculated at 4% for the GPP EI business unit, 4% for the GPP MEP business unit, and 92% for the Gas Pipelines and Processing–Shared Services business unit, or GPP SS, resulting in a business unit multiplier of 1.15 out of 2.0. For 2014, Mr. Neyland's performance measure is calculated at 100% for the GPP SS business, resulting in a business unit multiplier of 1.15 out of 2.0. For 2014, Mr. Loiacono's and Ms. Coy's performance measure is calculated at 100% for the GPP MEP business unit, resulting in a business unit multiplier of 0.86 out of 2.0. For 2014, Mr. Puckett's performance measure is calculated at 81% for the GPP MEP business unit and 19% for the GPP EI business unit, resulting in a business unit multiplier of 1.00 out of 2.0.

Mr. McGill retired from his positions with our General Partner and its affiliates on December 31, 2014. Mr. McGill received an advance lump sum payment of $158,476, less applicable withholdings for amounts foregone under the STIP.

The business unit multipliers upon which the NEO's STIP is calculated are included in the following tables. They reflect rounding and range from 0 to 2.0, with 1.0 meaning that the performance measure was met. The business units include us, but also include portions of other Enbridge businesses.

Gas Pipelines & Processing - Enbridge Inc.					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Multiplier**	**Weighted Multiplier**
Safety, Operations & Integrity	30%	Health and Safety Training	5%	1.77	0.53
		Safety Observations	5%		
		Incident Investigation Action Items	5%		
		Total Recordable Injury Frequency	5%		
		Process Safety Incident Frequency	10%		
Financial	40%	Budgeted Earnings	40%	1.65	0.66
Commercial	30%	Re-Contracting	12%	1.40	0.42
		Newly Secured Growth Projects	18%		
Business Unit Performance Multiplier					**1.61**

Gas Pipelines & Processing - Midcoast Operating					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Multiplier**	**Weighted Multiplier**
Safety	20%	Health and Safety Training Safety Observations Incident Investigation Action Items Total Recordable Injury Frequency	5% 5% 5% 5%	1.65	0.33
Operations & Integrity	25%	Integrity Management & Process Safety	25%	1.92	0.48
Financial	40%	Midcoast Distributable Cash Flow	40%	0	0
Commercial	10%	Newly Secured Growth Projects	10%	0	0
Employee Engagement	5%	Career Development	5%	1.01	0.05
Business Unit Performance Multiplier					**0.86**

Gas Pipelines & Processing - Shared Services					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Multiplier**	**Weighted Multiplier**
Safety	20%	Health & Safety Training Safety Observations Incident Investigation Action Items Total Recordable Injury Frequency	5% 5% 5% 5%	1.65	0.33
Operations & Integrity	25%	Integrity Management & Process Safety	25%	1.92	0.48
Financial	40%	Midcoast Distributable Cash Flow U.S. Liquids and Offshore Budgeted Earnings	22% 18%	0.73	0.29
Commercial	10%	Newly Secured Growth Projects	10%	0	0
Employee Engagement	5%	Career Development	5%	1.01	0.05
Business Unit Performance multiplier					**1.15**

Individual Performance

Each of the NEOs establishes individual goals at the beginning of each year by which individual performance is measured. These goals are based on areas of strategic and operational emphasis related to their respective portfolios, development of succession candidates, employee engagement, community involvement and leadership. Individual performance ratings are recommended to the HRC Committee by the President & Chief Executive Officer of Enbridge for Mr. Harper. Whereas the individual performance ratings for the remaining NEOs are recommended by their respective leaders to the Enbridge executive leadership team, including the President & Chief Executive Officer of Enbridge.

Summary of 2014 Performance Multipliers

The following table summarizes the corporate, business unit and individual performance multipliers for each NEO, associated weights and overall performance multiplier result:

NEO	Corporate Performance(a) (Weight x Multiplier)	Business Unit Performance(b) (Weight x Multiplier)	Individual Performance(c) (Weight x Multiplier)	Overall Performance Multiplier (a+b+c)
C. Gregory Harper	25% x 0.70 = 0.18	50% x 1.24 = 0.62	25% x 1.60 = 0.40	1.20
Mark A. Maki	25% x 0.70 = 0.18	50% x 1.15 = 0.57	25% x 1.55 = 0.39	1.14
Stephen J. Neyland	25% x 0.70 = 0.18	50% x 1.15 = 0.57	25% x 1.65 = 0.41	1.16
John A. Loiacono	25% x 0.70 = 0.18	50% x 0.86 = 0.43	25% x 1.45 = 0.36	0.97
Kerry C. Puckett	25% x 0.70 = 0.18	50% x 1.00 = 0.50	25% x 1.60 = 0.40	1.08
Janet L. Coy	25% x 0.70 = 0.18	50% x 0.86 = 0.43	25% x 2.30 = 0.57	1.18
Terrance L. McGill(1)	N/A	N/A	N/A	N/A

(1) Effective December 31, 2014, Mr. McGill retired from Enbridge and its affiliates. As such, his retirement benefits included a lump sum payment for 2014's STIP and is reported under the column titled "All Other Compensation" in the "Summary Compensation Table".

Based on the overall performance multiplier determined from the above table, short term incentive awards for our NEOs were calculated as follows:

NEO	Base Salary (a)	Target (b)	Overall Performance Multiplier (c)	Calculated STIP(1) =(a) x (b) x (c)	Actual STIP(1)
C. Gregory Harper	$414,000	60%	1.20	$296,838	$273,254
Mark A. Maki	359,900	40%	1.14	163,755	164,251
Stephen J. Neyland	263,555	35%	1.16	107,234	122,234
John A. Loiacono	261,773	35%	0.97	88,643	66,482
Kerry C. Puckett	275,000	35%	1.08	103,469	113,857
Janet L. Coy	258,000	35%	1.18	106,554	106,555
Terrance L. McGill(2)	N/A	N/A	N/A	N/A	N/A

(1) Calculated and actual results may vary from mathematical results due to proration of changes to STIP targets throughout the year, rounding and/or discretionary adjustments.

(2) Effective December 31, 2014, Mr. McGill retired from Enbridge and its affiliates. As such, his retirement benefits included a lump sum payment for 2014's STIP and is reported under the column titled "All Other Compensation" in the "Summary Compensation Table".

The calculated STIP may be adjusted for Mr. Harper by a recommendation of the President & Chief Executive Officer of Enbridge to the HRC Committee, which must approve any such recommendation. Any adjustments for the remaining NEOs would be approved by the President & Chief Executive Officer of Enbridge.

Medium and Long-Term Incentives

Enbridge has four plans that make up its medium and long-term incentive program for senior management:

- A performance stock unit plan, or PSUP, which includes three-year phantom shares with performance conditions that impact payout;
- A performance stock option plan, or PSOP, that includes eight-year options to acquire Enbridge common shares with performance and time vesting conditions;

- An incentive stock option plan, or ISOP, which includes 10-year stock options to acquire Enbridge common shares with time vesting conditions; and
- A restricted stock unit plan, or RSUP, which includes 35-month phantom shares with time vesting conditions.

Only Enbridge Executive Vice Presidents, which include Mr. Harper, are eligible to receive grants under the PSOP.

MEP has one additional plan that makes up its medium and long-term incentive program for senior management, which all NEOs are eligible for:

- A long-term incentive plan, or LTIP, which includes restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights with performance conditions that impact payout.

Enbridge believes that the combination of these medium and long-term incentive plans aligns a component of executive compensation with the interests of Enbridge shareholders beyond the current year. A significant percentage of the value of the annual long-term incentive awards to the NEOs is contingent on meeting performance criteria, such as share price hurdles or other performance measures under the LTIP and PSUP. Specifically, when earnings targets are achieved, the share price increases over the long term and when Enbridge common shares perform well relative to its peer organizations, the value of the medium and long-term incentive is maximized for the executives while also benefitting shareholders. The mix of medium and long-term incentive programs and total target medium and long-term incentive opportunity, expressed as a percentage of base salary, are as follows:

NEO	Target Medium & Long-term Incentives	Amount Each Plan Contributes to Total Target Grant		
		Performance Stock Units	Performance Stock Options[(1)]	Incentive Stock Options
C. Gregory Harper	200.0%	70.0%	60.0%	70.0%
Mark A. Maki	85.0%	25.5%	—	59.5%
Terrance L. McGill[(2)]	85.0%	25.5%	—	59.5%
Stephen J. Neyland	70.0%	21.0%	—	49.0%
John A. Loiacono	70.0%	21.0%	—	49.0%
Kerry C. Puckett	70.0%	21.0%	—	49.0%
Janet L. Coy	70.0%	21.0%	—	49.0%

(1) Performance stock options are granted approximately once every five years to Enbridge executive officers only, and they are intended to cover a five year period. The above table displays the intended annualized value. The last regular performance stock option grant was in 2012, which was intended to provide annual value over the period from 2012 – 2016; however, Mr. Harper was provided an initial grant of performance stock options upon his hire in 2014 to cover the period from 2014 to 2016.

(2) Effective December 31, 2014, Mr. McGill retired from Enbridge and its affiliates. He is eligible to receive benefits in accordance with the terms of the applicable plans and any outstanding award agreements.

With the exception of Mr. Harper, actual award values, expressed as a percentage of base salary, range between 0% and 200% of the target medium and long-term incentive opportunity, based on individual performance history, succession potential, retention considerations and market competitiveness. Discretionary adjustments may also be considered.

PSUP

The PSUP is a three-year performance-based unit plan. Performance measures and targets are established at the start of the term to reflect levels of performance that would be considered weak, average or exceptional. Achievement of the performance targets can decrease or increase the final award value in a range of 0% to 200%. PSUs do not involve the issuance of any shares of common stock of Enbridge. Throughout the term, units are added to the grants as if dividends were received and reinvested into additional units based on the actual dividend rate for shares of Enbridge common stock. Awards are granted annually and paid in cash at the end of a three-year term based on two performance criteria that were established for the grant: EPS and relative price to earnings ratio, or P/E Ratio, each of which are weighted at 50%. These metrics remain applicable for the 2014 grant.

The EPS performance reflects Enbridge's commitment to its shareholders to achieve earnings that meet or exceed industry growth rates. Enbridge established the EPS target to reflect performance that would be consistent with the average growth rate forecast of peer companies over a comparable time period. The EPS required to achieve a two multiplier (the maximum) would demonstrate achievement of compound annual growth consistent with exceptional industry growth rate and would represent exceptional performance to the investment community. Performance must at least meet 3% compound annual growth in EPS for a threshold payment, below which the multiplier would be zero.

The second performance criterion is the Enbridge P/E Ratio relative to a selected comparative group of companies. Enbridge's price to earnings performance has historically been very strong, therefore performance below the median of the peer group results in a multiplier of zero, performance between the median and 75th percentile results in a multiplier of one and performance above the 75th percentile results in a multiplier of two. The following table presents the comparative group for the P/E Ratio.

Price/Earnings Ratio – Comparative Group of Companies	
Ameren Corporation	OGE Energy Corp.
Canadian Utilities Limited	ONEOK, Inc.
Centerpoint Energy, Inc.	PG&E Corporation
Emera Incorporated	Sempra Energy
Fortis Inc.	Spectra Energy Corp.
National Fuel Gas Company	TransAlta Corporation
NiSource Inc.	TransCanada Corporation

This peer group of companies was selected because they are all capital market competitors of Enbridge, have a similar risk profile and are in a comparable sector.

PSOP

Performance stock options align the Enbridge executive leadership team, including Mr. Harper, with its shareholders by tying vesting to the achievement of defined performance criteria. Once the performance hurdles are met, exercisability is subject to time requirements. Enbridge grants performance stock options to its executives approximately every five years with eight year terms that become exercisable over a period of five years at a rate of 20% per year provided the performance criteria are met. The approach used to determine the common share price hurdles was determined from the Enbridge long-range plan which is integrated with the strategic growth plans of Enbridge and historic industry P/E Ratio information.

Enbridge granted performance stock options to Mr. Harper in 2014 in conjunction with his employment with Enbridge to cover the period from 2014 to 2016. However, the performance criteria for Mr. Harper's 2014 performance stock options vest in equal annual installments over four years (instead of 5), subject to Enbridge common share price hurdles of $53.00 CAD and $58.00 CAD, weighted at 60% and 40%, respectively, which must be met by February 2019. As of December 31, 2014, the Enbridge common share price target of $53.00 CAD, for the 2014 grant has been met but no options have time vested, therefore none of the grant is exercisable. For clarity, the following table further describes the vesting provisions and performance criteria of Mr. Harper's 2014 performance stock option grant:

Share price	Year 1	Year 2	Year 3	Year 4
Less than $53	0%	0%	0%	0%
Greater than $53 but less than $58	15%	30%	45%	60%
Greater than $58	25%	50%	75%	100%

Attribution	Year 1	Year 2	Year 3	Year 4
Summary compensation table reflection (*value provided equally over full term of grant)*	25% of grant value	25% of grant value	25% of grant value	25% of grant value

ISOP

Regular stock options focus the Enbridge executives on increasing shareholder value over the long-term through common share price appreciation. Stock options are granted annually to Enbridge executives entitling them to acquire Enbridge common shares at a price defined at the time of grant. These options become exercisable over a period of four years at a rate of 25% per year, and the term of each grant is ten years.

RSUP

The RSUP is a plan that awards RSUs which have the same value as a common share of Enbridge stock, but are not traded in external financial markets. Throughout the term, units are added to the grants as if dividends were received and reinvested into additional units based on the actual dividend rate for common shares of Enbridge stock. At the end of the 35-month term, the units are paid in cash based on the weighted average price of an Enbridge common share on the NYSE for 20 trading days prior to the end of the term. Mr. Harper is the only NEO that participated in this plan for the year ended December 31, 2014 and was granted this upon his hire in January 2014.

LTIP

Under the LTIP, our General Partner may authorize the issuance of long-term equity based awards to directors, officers and employees of our General Partner or its affiliates, or to any consultants of our General Partner or other individuals who perform services for us. While we are an affiliate of Enbridge, however, any directors and consultants who are not also employees of our General Partner or its affiliates will not be eligible to receive awards under the LTIP. The LTIP provides for the grant, from time to time at the discretion of the board of directors of our General Partner or any delegate thereof, subject to applicable law, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and other unit-based awards. While we are an affiliate of Enbridge, however, awards will only be granted following a recommendation of the board of directors or compensation committee of Enbridge. The purpose of awards under the LTIP is to provide additional incentive compensation to individuals providing services to us, and to align the economic interests of such individuals with the interests of our unitholders. The LTIP limits the number of units that may be delivered pursuant to vested awards to 3,750,000 Class A common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units subject to awards that are cancelled, forfeited, withheld to satisfy exercise prices or tax withholding obligations or otherwise terminated without delivery of the common units will be available for delivery pursuant to other awards. We will be responsible for the cost of awards granted under our LTIP and all determinations with respect to awards to be made under our

LTIP will be made by the board of directors of our General Partner or any committee thereof that may be established for such purpose or by any delegate of the board of directors or such committee, subject to applicable law, which we refer to as the plan administrator. As of December 31, 2014, no grants had been issued under this plan.

Service Agreements and Allocation of Compensation to the Partnership

EEP provides managerial, administrative, operational and director services to us pursuant to the intercorporate services agreement, which services are ultimately provided through service agreements among EEP, Enbridge Management and Enbridge and its affiliates. Pursuant to the intercorporate services agreement, we reimburse EEP for our allocated portion of the costs of such services. Through a services agreement between our General Partner and EEP, we are charged for the services of executive management resident in the United States, including all of the NEOs.

EEP determines a budgeted allocation rate for our NEOs' compensation in accordance with the terms of the agreements it has entered into with Enbridge Management, Enbridge and its affiliates and provides reimbursement for costs of services based on allocation method provided under those agreements. Since the allocation rate is estimated, the actual time spent by an NEO on behalf of EEP (which includes services to us) may vary from the budgeted allocation rate, and EEP may be allocated more or less of that NEO's compensation than the actual percentage of his time spent on its behalf in a given year. The amount of our NEOs' compensation that is allocated by EEP to us is determined in accordance with the terms of the intercorporate services agreement. For additional information, regarding our intercorporate services agreement, please read Item 13. *Certain Relationships and Related Transactions, and Director Independence—Intercorporate Service Agreements.*

The compensation of our NEOs included in the tables below is established by Enbridge as described above. We selected our top three most highly compensated executives (other than our principal executive officer and our principal financial officer) based on current expectations regarding the amount of time such executives will devote to us and services related to our business. We have included in the following tables the full amount of compensation and related benefits provided for each of the NEOs for 2014, 2013 and 2012, together with the approximate time spent by each NEO on MEP's behalf (and on EEP's behalf for 2013 and 2012 before the Offering) and the approximate amount of compensation cost allocated to MEP for the years ended December 31, 2014, 2013 and 2012, as applicable. Since the amount of NEO compensation allocated to MEP is based on estimates of time spent on MEP's behalf by the particular NEO, the compensation amounts allocated to MEP may not exactly reflect the amount of time that a certain NEO devoted to MEP's business. We are a newly established partnership that was formed in May 2013. While no specific amounts of such compensation were allocated to us for 2013 and 2012, the financial statements of Midcoast Operating, L.P., our predecessor for accounting purposes, includes an allocation of NEO compensation to EEP.

SUMMARY COMPENSATION TABLE

Name and[1] Principal Position(a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards[1] ($) (e)	Option Awards[2] ($) (f)	Non-Equity Incentive Plan Compen-sation[3] ($) (g)	Change in Pension Value and Nonqualified Deferred Compen-sation Earnings ($) (h)	All Other Compen-sation[4] ($) (i)	Total ($) (j)	Approximate Percentage of Time Devoted to Midcoast Energy Partners, L.P.[6] (%)	Approximate Amount Allocated to Midcoast Energy Partners, L.P.[6] ($)
C. Gregory Harper[5]	2014	377,167	370,000	471,315	197,841	273,254	119,000	49,792	1,858,369	45	836,266
President (Principal	2013	—	—	—	—	—	—	—	—	—	—
Executive Officer) and Director	2012	—	—	—	—	—	—	—	—	—	—
Mark A. Maki	2014	361,529	—	592,158	392,221	164,251	1,326,000	50,872	2,887,031	20	577,406
Senior Vice President	2013	370,440	—	429,868	338,047	220,170	(236,000)	47,392	1,169,917	75	808,311
(Former Principal Executive Officer) and Director	2012	332,075	—	590,857	289,938	183,630	813,000	46,646	2,256,146	95	1,896,178
Stephen J. Neyland	2014	260,718	—	384,811	238,549	122,234	523,000	38,175	1,567,487	45	705,369
Vice President—Finance	2013	248,637	—	272,116	200,840	134,610	3,000	43,647	902,850	90	780,931
(Principal Financial Officer)	2012	235,097	—	249,187	163,217	129,750	162,000	39,633	978,884	90	824,613
Terrance L. McGill	2014	393,118	—	639,252	368,402	N/A[7]	754,000	521,157[7]	2,675,929	90	2,408,336
(Retired) President and	2013	380,391	—	462,395	439,139	188,120	90,000	35,510	1,595,555	74	1,396,922
Chief Commercial Officer	2012	366,292	—	712,584	415,786	177,160	371,000	37,190	2,080,012	90	1,809,538
John A. Loiacono	2014	259,744	—	338,319	232,984	66,482	428,000	46,992	1,372,521	100	1,372,521
Vice President—	2013	251,334	—	259,101	206,463	115,430	(27,000)	44,909	850,237	100	850,237
Commercial Activities	2012	242,302	—	330,999	184,503	100,290	196,000	44,691	1,098,785	100	1,098,785
Kerry C. Puckett	2014	266,230	—	331,638	219,609	113,857	398,000	51,942	1,381,276	85	1,174,084
Vice President—	2013	245,823	—	243,797	203,528	115,370	1,000	43,853	853,371	100	853,371
Engineering and Operations Gathering & Processing	2012	235,650	—	365,813	181,120	98,920	188,000	42,620	1,112,123	100	1,112,123
Janet L. Coy	2014	256,000	—	231,789	200,056	106,555	405,000	39,294	1,238,694	100	1,238,694
Vice President—Natural	2013	—	—	—	—	—	—	—	—	—	—
Gas Marketing	2012	—	—	—	—	—	—	—	—	—	—

(1) The compensation expense associated with Performance Stock Units, or PSUs, granted on January 1 in 2014, 2013 and 2012 for each NEO, and the Restricted Stock Units, or RSUs, awarded in January 2014, with respect to Mr. Harper, that are reflected in this column represent one-third of the market value for each year the PSUs and RSUs are outstanding. The PSUs are measured based on the number of respective units granted, dividends reinvested, cliff-vested, the actual or forecast performance multiplier (RSUs do not have performance multipliers used in determining the payout amount). Both PSUs and RSUs are priced at the date of grant, then revalued each quarter using the spot rate on the last day of each quarter. For example, 2014 includes one-third of the market values for PSUs issued in 2014, 2013 and 2012 and one-third of the market values for RSUs issued in 2014. In 2014, the compensation expense recorded for PSUs granted in 2014, 2013 and 2012 include performance multipliers for years 2014 thru 2012, which are estimated based upon the expected or achieved levels of performance in relation to established targets for each year. For years prior to the year a payout is made, a performance multiplier is forecast based upon the progress made in attaining the established performance criteria unless the actual multiplier has been determined. Refer also to *Footnote 3* of the *Grants of Plan—Based Awards* table for additional discussion regarding the PSUs. The grant date fair value for each PSU and RSU grant represents the weighted average closing price of an Enbridge common share as quoted on the NYSE for the 20 consecutive days prior to the grant date of January 1 each year. PSUs and RSUs granted for 2014 were denominated in USD at a grant price of $41.65 USD, while the PSUs granted in 2013 and 2012 were granted at a grant price of $42.27 and $35.75, respectively. The actual payout amounts for the 2012 PSUs that vested on December 31, 2014 were based on the 20 day weighted average share prices prior to December 31, 2014 of $49.73 USD. Compensation expense as reported in the Summary Compensation Table above for Stock Awards has been determined using the following assumptions:

PSU Grant Date Prices	2014	2013	2012
Grant date fair market value (20-day average before January 1) USD (NYSE)	$41.65	$42.27	$35.75

Revaluation Date	Mar-31	Jun-30	Sep-30	Dec-31
2012 - 2014 Grants				
Share Price/Spot Rate USD (NYSE)	$45.29	$47.47	$47.88	$51.41
2012 PSUs assumed performance multiplier	1.94	1.94	1.94	1.94
2013 PSUs assumed performance multiplier	2.00	2.00	2.00	2.00
2014 PSUs assumed performance multiplier	2.00	2.00	2.00	2.00

(2) Under the authoritative accounting provisions for share-based payments, the annual expenses for option awards that are granted under the Enbridge Incentive Stock Option Plan (2007), or ISOP, and the PSOP are determined by computing the fair value of the options on the grant date using the Black-Scholes option pricing model. The following assumptions were used in computing the fair value of the options on the grant date for the respective option pricing model employed and the indicated year:

	ISOP[a]			PSOP[b]		
Assumption	2014	2013	2012	2014	2013	2012
Expected option term in years	6	6	6	6.5	N/A	N/A
Expected volatility	20.07%	19.97%	22.80%	15.00%	N/A	N/A
Expected dividend yield	2.87%	2.77%	2.95%	2.80%	N/A	N/A
Risk-free interest rate	1.90%	1.05%	1.17%	1.70%	N/A	N/A

(a) All ISOs were granted in $USD.

(b) All PSOs were granted in $CAD.

The fair value of options granted as computed using the above assumptions is expensed over the shorter of the vesting period for the options and the period to early retirement eligibility. The exercise price and fair value information for all option grants have been converted to USD as set forth in the table below:

	ISOP			PSOP		
	2014	2013	2012	2014[c]	2013	2012
Vesting period in years	4	4	4	4	N/A	N/A
Exercise price in USD (NYSE)	$44.09	$43.84	$38.65	$ 44.14	N/A	N/A
Exercise price in CAD (TSX)	N/A	N/A	N/A	$ 48.81	N/A	N/A
Grant date exchange rate for $1 USD	N/A	N/A	N/A	$1.1057	N/A	N/A
Option fair value on grant date in USD	$ 6.68	$ 6.26	$ 6.11	$ 5.22	N/A	N/A
Option fair value on grant date in CAD	N/A	N/A	N/A	$ 5.77	N/A	N/A
Average year outstanding exchange rate for $1 USD	N/A	N/A	N/A	$1.1055	N/A	N/A

(c) Prices show in USD for the PSOs granted (on January 30, 2014) in CAD are converted to USD using the exchange rates detailed above.

(3) Non-equity incentive plan compensation represents awards that are paid in February of each year for amounts that are earned in the immediately preceding fiscal year under the Enbridge STIP as discussed in the above Compensation Discussion and Analysis.

(4) The table which follows labeled “All Other Compensation” sets forth the elements comprising the amounts presented in this column.

(5) Mr. Harper was elected as an officer of Enbridge Management and EEP’s General Partner in April 2014. Mr. Harper is also an executive officer of Enbridge with responsibility for other affiliates of Enbridge in addition to those for EEP’s General Partner and Enbridge Management. For more information, please see Part III, Item 10. *Directors, Executive Officers and Corporate Governance*.

(6) Because we are a newly established partnership that was formed in May 2013, no specific amounts of NEO compensation were allocated to us for the years ended December 31, 2013 and 2012. While we had no specific amounts of such compensation allocated to us for 2013 and 2012, the financial statements of Midcoast Operating, L.P., our predecessor for accounting purposes, includes an allocation of NEO compensation to EEP.

(7) Other Compensation for Mr. McGill includes benefits due to Mr. McGill’s retirement from Enbridge and its affiliates effective December 31, 2014.

(8) Historically we have grouped paid time off, PTO, not taken, paid in cash with “Salaries”. We are now including this category of benefits under “Other Compensation” and have retroactively applied this logic to prior periods presented.

ALL OTHER COMPENSATION
(For the years ended December 31, 2014, 2013 and 2012)

Name	Year	Flexible Benefits[1] $	401(k) Matching Contributions[2] $	Other Benefits[3] $	Total
C. Gregory Harper	2014	32,219	13,000	4,573	49,792
	2013	—	—	—	—
	2012	—	—	—	—
Mark A. Maki	2014	20,000	13,000	17,872	50,872
	2013	20,000	12,750	14,642	47,392
	2012	20,000	12,500	14,146	46,646
Stephen J. Neyland	2014	20,000	13,000	5,175	38,175
	2013	20,000	12,750	10,897	43,647
	2012	20,000	11,786	7,847	39,633
Terrance L. McGill	2014	20,000	13,000	488,157[4]	521,157
	2013	20,000	12,750	2,760	35,510
	2012	20,000	12,500	4,690	37,190
John A. Loiacono	2014	20,000	13,000	13,992	46,992
	2013	20,000	12,750	12,159	44,909
	2012	20,000	12,288	12,403	44,691
Kerry C. Puckett	2014	20,000	13,000	18,942	51,942
	2013	20,000	12,740	11,113	43,853
	2012	20,000	11,944	10,676	42,620
Janet Coy	2014	20,000	12,887	6,407	39,294
	2013	—	—	—	—
	2012	—	—	—	—

(1) Flexible benefits for our NEOs represent a perquisite allowance that is paid in cash as additional compensation.

(2) Our NEOs that participate in the Enbridge Employee Services, Inc. Savings Plan, referred to as the 401(k) Plan, may contribute up to 50% of their base salary, which is matched up to 5% by Enbridge. Both individual and matching contributions are subject to limits established by the Internal Revenue Service. Enbridge contributions are used to purchase Enbridge common shares at market value and employee contributions may be used to purchase Enbridge common shares or 23 designated funds.

(3) Other benefits include parking, mortgage interest payments, fitness, and vacation not taken and paid out in cash for the NEOs.

(4) As a result of Mr. McGill's retirement from Enbridge and its affiliates on December 31, 2014, he received benefit payments for severance, forgone STIP and COBRA coverage.

The PSUs are granted to the NEOs pursuant to the PSUP, the RSUs are granted pursuant to the RSUP and stock options are granted pursuant to the ISOP and the PSOP. Awards under these plans provide long-term incentive and are administered by the HRC Committee of Enbridge. Although stock options remain outstanding that were granted under the Enbridge Incentive Stock Option Plan (2002), no further stock options will be granted under this plan. The performance stock units, restricted stock units and stock option granted in 2012 through 2014 to our NEOs are denominated in USD. The exception is Mr. Harper, who was awarded a PSO grant in CAD. The three tables which follow set forth information concerning performance stock units, restricted stock units and stock options granted during the year ended December 31, 2014, outstanding at December 31, 2014 and the number of awards vested and exercised during the year ended December 31, 2014 by each of the NEOs.

GRANTS OF PLAN-BASED AWARDS

Name (a)	Plan Name[1] (b)	Approval Date (b)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[2] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[3] Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Option Awards: Number of Securities Underlying Options[4] (#) (j)	Exercise or Base Price of Option Awards[4] ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards[3][4] ($) (l)
C. Gregory Harper	PSUP	11-Feb-14	1-Jan-14	—	—	—	—	6,700	13,400	—	—	279,055
	ISOP	11-Feb-14	13-Mar-14	—	—	—	—	—	—	34,650	44.09	231,462
	RSUP	11-Feb-14	30-Jan-14	—	—	—	—	12,400	—	—	—	516,460
	PSOP[5]	11-Feb-14	13-Mar-14	—	—	—	—	—	—	138,080	44.14	720,555
	STIP	2-Feb-15	27-Feb-15	—	248,400	496,800	—	—	—	—	—	—
Mark A. Maki	PSUP	11-Feb-14	1-Jan-14	—	—	—	—	5,050	10,100	—	—	210,333
	ISOP	11-Feb-14	13-Mar-14	—	—	—	—	—	—	63,050	44.09	421,174
	STIP	2-Feb-15	27-Feb-15	—	143,960	287,920	—	—	—	—	—	—
Stephen J. Neyland	PSUP	11-Feb-14	1-Jan-14	—	—	—	—	2,500	5,000	—	—	104,125
	ISOP	11-Feb-14	13-Mar-14	—	—	—	—	—	—	36,300	44.09	242,484
	STIP	2-Feb-15	27-Feb-15	—	92,244	184,489	—	—	—	—	—	—
Terrance L. McGill	PSUP	11-Feb-14	1-Jan-14	—	—	—	—	4,600	9,200	—	—	191,590
	ISOP	11-Feb-14	13-Mar-14	—	—	—	—	—	—	55,150	44.09	368,402
	STIP	2-Feb-15	27-Feb-15	—	158,476	316,951	—	—	—	—	—	—
John A. Loiacono	PSUP	11-Feb-14	1-Jan-14	—	—	—	—	2,500	5,000	—	—	104,125
	ISOP	11-Feb-14	13-Mar-14	—	—	—	—	—	—	30,000	44.09	200,400
	STIP	2-Feb-15	27-Feb-15	—	91,621	183,241	—	—	—	—	—	—
Kerry C. Puckett	PSUP	11-Feb-14	1-Jan-14	—	—	—	—	2,450	4,900	—	—	102,043
	ISOP	11-Feb-14	13-Mar-14	—	—	—	—	—	—	29,350	44.09	196,058
	STIP	2-Feb-15	27-Feb-15	—	96,250	192,500	—	—	—	—	—	—
Janet L. Coy	PSUP	11-Feb-14	1-Jan-14	—	—	—	—	1,800	3,600	—	—	74,970
	ISOP	11-Feb-14	13-Mar-14	—	—	—	—	—	—	21,700	44.09	144,956
	STIP	2-Feb-15	27-Feb-15	—	90,300	180,600	—	—	—	—	—	—

(1) The abbreviated plan names are defined as follows:
a. PSUP refers to the Enbridge Performance Stock Unit Plan (2007), an equity-based incentive plan.
b. ISOP refers to the Enbridge Incentive Stock Option Plan (2007), a stock option plan.
c. PSOP refers to the Enbridge Performance Stock Option Plan (2007), a stock option plan generally for Canadian based employees.
d. STIP refers to the Enbridge Short Term Incentive Plan (2006), a non-equity performance-based incentive plan.
e. RSUP refers to the Enbridge Restricted Stock Unit Plan (2006), an equity-based incentive plan.

(2) The estimated future payouts under non-equity incentive award plans represent awards under the Enbridge STIP as presented above in the Compensation Discussion and Analysis under the section labeled Short-Term Incentive Plan.

(3) Our NEOs are eligible to receive annual grants of PSUs, under the PSUP, an equity-based, long-term incentive plan, administered by a committee of the board of directors of Enbridge. The initial value of each of these PSUs on the grant date is equivalent to the volume weighted average closing price of one Enbridge common share as quoted on the TSX or NYSE for the 20 trading days immediately preceding the start of the performance period. Awards under the PSUP are paid out in cash at the end of a three-year performance cycle based on: (1) an EPS target for Enbridge based on levels of performance that are considered weak, average or exceptional and (2) the P/E Ratio of an Enbridge common share relative to a defined group of peer organizations established in advance by a committee of the board of Enbridge. Payments under the PSUP may be increased up to 200% of the original award when Enbridge exceeds the established targets. If Enbridge fails to meet threshold performance levels, no payments are made under the PSUP. Notional dividends are paid on the PSUs which are invested in additional PSUs at the then current market price for one share of Enbridge common stock, which are not included in the estimated future payout amounts, but have been included in the compensation associated with stock awards in the Summary Compensation Table. Enbridge does not issue any common shares in connection with the PSUP.

No payments will be paid out related to the PSUs initially granted if the performance criteria discussed above is not met. The target level at which PSUs are issued represents 100% of the number of PSUs initially granted and attainment of the established performance criteria. The maximum level at which PSUs may be issued is 200% of the number of PSUs initially granted and may occur when Enbridge exceeds the established performance criteria. PSUs vest at the end of a three year performance period that begins on January 1 of the year granted and during the term the PSUs are outstanding, a liability and expense are recorded by Enbridge based on the number of PSUs outstanding (including additional PSUs resulting from reinvesting dividends) and the current market price of an Enbridge common share with an assumed performance multiplier that is determined quarterly based on progress towards achieving the established performance criteria, until the end of the performance period at which point the performance multiplier is known. The grant date fair value for each PSU granted to each of our NEOs in 2014 was $41.65 USD, representing the volume weighted average closing price of one Enbridge common share as quoted on the NYSE for the 20 trading days immediately preceding the start of the performance period that began on January 1, 2014.

(4) The ISOP is administered by a committee of the Enbridge board of directors. If an option is awarded at a time when a blackout period is in effect, the grant price of the option will be set on the sixth trading day following the termination of the blackout period, and will be based on the weighted average trading price of an Enbridge common share on the NYSE for the five trading days immediately preceding. If an option is granted when a blackout period is not in effect, the exercise price may not be less than 100% the fair market value as at grant date. During 2014, each of the NEOs received grants of Enbridge incentive stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The exercise price of the incentive stock options at the time of grant was $44.09 USD for our NEOs.

The amounts included as the grant date fair value for the 2014 incentive stock option awards represent the amount determined by computing the fair value of the options in accordance with the authoritative guidance for share-based payments on the grant date using the Black-Sholes option pricing model with the following assumptions:

- 6 years expected term;
- 20.067% expected volatility;
- 2.87% expected dividend yield; and
- 1.90% risk free interest rate

The fair value of options granted as computed using these assumptions is $6.68 USD. The grant date fair value is expensed over the shorter of the vesting period for the options, generally four years, and in the year granted for employees age 55 and over and eligible for early retirement. Mr. McGill was aged 55 or over and eligible for early retirement as of the grant date and, as a result, the grant date fair value of options he was awarded is expensed in the year granted.

(5) For Mr. Harper's PSOs, the threshold at which these PSOs are paid out represents 60% of the number of PSOs initially awarded and is the lowest level at which PSOs will be paid out. This is based on meeting the first performance criteria of having Enbridge's share price hurdle of $53.00 CAD being met during 2014. The maximum level at which PSOs may be issued is 100% of the number of PSOs initially when Enbridge exceeds the established performance criteria (having a share price above $58.00 CAD). The base price of the option of $5.77 CAD and the grant value have been converted to USD using an exchange rate of $1.1057 CAD = $1 USD.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

	Option Awards				Stock Awards	
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable[(1)] (c)	Option Exercise Price[(2)] ($) (e)	Option Expiration Date[(1)] (f)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[(4)] (#) (i)	Equity Incentive Plan Awards: Market or Payout of Value Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
C. Gregory Harper	—	34,650	44.09	13-Mar-24	6,885	707,890
	—	138,080[(3)]	44.14[(3)]	15-Aug-20	12,742[(5)]	655,063
Mark A. Maki	—	63,050	44.09	13-Mar-24	5,189	533,559
	15,900	47,700	43.84	27-Feb-23	4,124	424,028
	30,825	30,825	38.65	2-Mar-22		
	57,300	19,100	28.99	14-Feb-21		
Stephen J. Neyland	—	36,300	44.09	13-Mar-24	2,569	264,138
	10,263	30,787	43.84	27-Feb-23	2,432	250,068
	19,550	19,550	38.65	2-Mar-22		
	22,300	11,150	28.99	14-Feb-21		
	7,700	—	21.97	16-Feb-20		
	2,750	—	15.80	25-Feb-19		
Terrance L. McGill	—	55,150	44.09	13-Mar-24	4,727	486,014
	17,538	52,612	43.84	27-Feb-23	4,547	467,518
	34,025	34,025	38.65	2-Mar-22		
	63,900	21,300	28.99	14-Feb-21		
	49,000	—	21.97	16-Feb-20		
John Loiacono	—	30,000	44.09	13-Mar-24	2,569	264,138
	9,538	28,612	43.84	27-Feb-23	2,485	255,504
	18,600	18,600	38.65	2-Mar-22		
	38,250	12,750	28.99	14-Feb-21		
	6,400	—	21.97	16-Feb-20		
Kerry Puckett	—	29,350	44.09	13-Mar-24	2,518	258,855
	9,313	27,937	43.84	27-Feb-23	2,432	250,068
	17,900	17,900	38.65	2-Mar-22		
	33,450	11,150	28.99	14-Feb-21		
	23,800	—	21.97	16-Feb-20		
	42,300	—	15.80	25-Feb-19		
	10,715	—	20.17	19-Feb-18		
Janet Coy	—	21,700	44.09	13-Mar-24	1,850	190,179
	7,400	22,200	43.84	27-Feb-23	1,692	173,960
	12,350	12,350	38.65	2-Mar-22		
	23,100	7,700	28.99	14-Feb-21		

(1) Each ISO award has a 10-year term and vests pro-rata as to one fourth of the option award beginning on the first anniversary of the grant date; thus the vesting dates for each of the option awards in this table can be calculated accordingly. As an example, for Mr. Maki's grant that expires on February 14, 2021, the grant date would be 10 years prior or February 14, 2011 and as a result, the remaining unexercisable amounts become fully vested on February 14, 2015 representing four years following the grant date.

(2) Where appropriate, all exercise prices and valuation prices prior to 2011 have been adjusted for the April 2011 Partnership stock split and Enbridge's May 2011 stock split.

(3) PSOs were provided to Mr. Harper on January 30, 2014, and are similar to the incentive stock options, except that the quantities that become exercisable are subject to both time and performance requirements. PSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge common share for each option held when the specified time and performance conditions are met. Upon the performance hurdles being met, the PSOs are also time vested 25% annually over four years. As of December 31, 2014, the Enbridge common share price target of $53.00 CAD has been met, but no options have time vested, therefore

none of the grant is exercisable. The PSOs denominated in CAD have been converted to USD using the exchange rate on the grant date of $48.81 CAD based on the TSX converted to $44.14 USD at the conversion rate of $1.1057 CAD = $1 USD.

(4) The unearned common shares, units or other rights that have not vested under stock awards represent PSUs that have not yet reached the end of their term. The PSUs become vested upon achieving the established performance criteria discussed in Footnote 3 of the *Grants of Plan-Based Awards* table, at the end of the term. The amounts represented in the column are the number of units that have not vested at the weighted average noon rate for 20 trading days at year end 2014 of one Enbridge common share on the NYSE at $51.41. The market or payout values presented assume a performance multiplier of 2.0 for PSUs granted in 2014 and 2013, which amounts represent the maximum level attainable.

(5) The unearned common shares, units or other rights that have not vested under stock awards represent RSUs that have not yet reached the end of their term. The RSUs become vested at the end of the term. The amounts represented in the column are the number of units that have not vested at the common share price of one Enbridge common share on the NYSE at December 31, 2014 equating to $51.41 per share.

OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting[1] (#) (d)	Value Realized on Vesting[2] ($) (e)
C. Gregory Harper	—	—	—	—
Mark A. Maki	84,900	2,428,584	4,842	452,716
Terrance L. McGill	198,000	5,744,304	5,386	503,583
Stephen J. Neyland	—	—	3,917	366,242
John A. Loiacono	40,700	1,185,664	2,938	274,682
Kerry C. Puckett	37,085	1,016,622	2,884	269,595
Janet L. Coy	17,000	387,345	1,959	183,121

(1) The number of common shares acquired on vesting for stock awards represents the number of PSUs issued in 2012 and the related dividends paid that were used to acquire additional PSUs, all of which matured on December 31, 2014. As discussed in Footnote 3 of the *Grants of Plan-Based Awards* table, no common shares are issued with respect to the PSUs that become vested; rather, cash is paid in an amount based on the value of an Enbridge common share at the maturity date and the level of achievement of the established performance goals. The payout for the PSUs granted in 2012 is expected to occur on or about March 13, 2015.

(2) The value realized on vesting is determined based on the 20-day volume weighted-average value of an Enbridge common share of $49.73 USD. In each case the common share price is multiplied by an estimated 1.88 performance factor multiplied by the number of PSUs for the PSUs that matured on December 31, 2014.

Pension Plan

Enbridge sponsors two qualified pension plans, the Retirement Plan for the Employees of Enbridge Inc. and Affiliates, or EI RPP, and the Enbridge Employee Services, Inc. Employees' Pension Plan, or QPP. These plans provide defined pension benefits, and cover employees in Canada and the United States, respectively. Both plans are non-contributory. Enbridge also sponsors supplemental nonqualified retirement plans in both Canada, referred to as EI SPP, and the United States, referred to as US SPP, which provide defined pension benefits for the NEOs in excess of the tax-qualified plans' limits. Mr. Maki is the only NEO that has pension credits from the EI RPP and EI SPP for prior years of service when he was in an Enbridge executive leadership role in Canada. We collectively refer to the EI RPP, the QPP, the EI SPP and the US SPP as the Pension Plans. Defined pension benefits under the grandfathered benefit of the Pension Plans are based on the employees' years of service and average final remuneration with an offset for Social Security benefits, while cash balance benefits provide annual pay and interest credits to notional member accounts.

For service prior to becoming a senior management employee, there are different pension benefits depending on an employee's hire date with Enbridge. Employees hired before January 1, 2002 have grandfathered benefits equal to: (a) 1.6% of the average of the participant's highest average annual salary multiplied by (b) the number of credited years of service. Other provisions are aligned with the senior management provisions described below. For employees hired after January 1, 2002, the Pension Plans provide cash balance benefits with pay credits ranging from 4%—10% depending on the employees' pensionable pay, age and years of service.

For service while a senior management employee, the Pension Plans provide a yearly pension payable in the normal form (60% joint and survivor) equal to: (a) 2% of the sum of (i) the average of the participant's highest annual base salary during three consecutive years out of the last ten years of credited service and (ii) the average of the participant's three highest annual performance bonus periods, represented in each period by 50% of the actual bonus paid, in respect of the last five years of credited service, multiplied by (b) the number of credited years of service. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Pension Plan are indexed at 50% of the annual increase in the consumer price index. All NEOs are currently senior management employees.

The table below illustrates the total annual pension entitlements at December 31, 2014 assuming the eligibility requirements for an unreduced pension have been satisfied. We have converted pension payable in CAD into USD at the rate of $1.1045 CAD = $1.00 USD, the average exchange rate for the year ended December 31, 2014. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	3.70% at year end 2014
Salary increases	None
Inflation	2.50% per year
Retirement age	Age when first eligible for an unreduced pension[1]
Terminations	None
Mortality Rates:	
Pre-retirement	None
Post-retirement	Society of Actuaries RP2014 annuity/non-annuitant table without collar adjustment with full generational mortality improvement under Scale MP 2014

(1) This is age 60 for all executives except for Mr. Maki and Mr. Neyland, who are eligible for an unreduced pension at age 55 and age 57, respectively.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service[1] (#) (c)	Present Value of Accumulated Benefit ($) (d)
C. Gregory Harper	US QPP	0.92	18,000
	US SPP	0.92	101,000
Mark A. Maki	EI RPP	1.92	111,000
	EI SPP	1.92	213,000
	US QPP	26.40	2,153,000
	US SPP	26.40	1,793,000
Stephen J. Neyland	US QPP	12.50	206,000
	US SPP	10.00	883,000
Terrance L. McGill	US QPP	12.51	258,000
	US SPP	12.84	2,516,000
John A. Loiacono	US QPP	12.50	217,000
	US SPP	11.75	1,047,000
Kerry C. Puckett	US QPP	12.50	200,000
	US SPP	10.42	959,000
Janet L. Coy	US QPP	12.50	220,000
	US SPP	10.08	999,000

(1) For all NEOs, with the exception of Mr. Maki, US SPP service represents years of service as a senior management employee. Mr. Maki has 15.00 years of service as a senior management employee.

Employment Agreements

In 2014, Enbridge entered into an executive employment agreement with C. Gregory Harper, Director and Executive Vice President—Gas Pipelines & Processing. The term of the agreement continues until the earlier of the executive officer's voluntary retirement in accordance with Enbridge's retirement policies for its senior employees, voluntary resignation, death or termination of employment by Enbridge of the applicable executive officer. None of the remaining NEOs have an employment agreement with us or any other Enbridge affiliate. Mr. Harper's agreement provides that Enbridge will pay severance benefits to Mr. Harper as set forth in the table below, if Mr. Harper's employment is terminated. Since 2007, it has been Enbridge's policy not enter into employment agreements granting "single trigger' voluntary termination rights in favor of the executive.

The following table provides a summary of the incremental compensation that Enbridge would pay to the applicable executive officer under the terms of his employment agreements upon the occurrence of one of the foregoing events:

Type of Termination	Base Pay	Short-term Incentive	Long-term Incentive	Benefits	Pension
Resignation *(Voluntary)*	None	Payable in full if executive has worked the entire calendar year. Otherwise none.	Performance stock units are forfeited. Vested options must be exercised within 30 days of resignation or by the end of the original term, whichever is sooner. Unvested stock options are cancelled.	None	Credited service no longer earned.
Retirement *(Voluntary)*	None	Current year's incentive is pro-rated based on retirement date.	Performance stock units are prorated to retirement date and the value and performance is assessed and paid at the end of the term. Non-qualified stock options continue to vest and vested options are exercisable for three years after the retirement date or until the end of the original term (whichever is sooner). ISOs have immediate vesting (for that which would have vested in the three years following retirement) and vested options can be exercised for three months after the retirement date or until the end of the original term (whichever is sooner). Performance stock options are prorated for the period of active employment in the 5 year period starting January 1 of the year of grant and ending the later of three years after retirement or 30 days after the date by which the share price targets must be met (or up to the date the option expires, whichever is earlier), as long as the share price targets are met.	Post retirement benefits begin.	Credited service no longer earned.
Constructive Dismissal *(Involuntary)* Not for Cause (Involuntary)	Base salary is paid out in a lump sum representing two years.	The average of short-term incentive awards received in the past two years multiplied by two times; plus the current year's short-term incentive, prorated based on service before employment was terminated.	Performance stock units are prorated to date of termination and the value and performance is assessed and paid at the end of the term. Vested stock options are exercisable in accordance with their terms. Unvested stock options are paid in cash.[1]	Benefits value is paid out in a lump sum over two years' value.	Two additional years of pension accrual are paid out in cash.

(1) Performance stock options are valued assuming all performance measures have been met.

Performance stock options have the same termination provisions as incentive stock options except:

- For retirement, we prorate their performance stock options for the period of active employment in the 5 year period starting January 1 of the year of grant. They can exercise these options until the later of three years after retirement or 30 days after the share price targets must be met (or up to the date the option expires, whichever is earlier), as long as the performance criteria are met;

- For death, unvested options are pro-rated and the plan assumes performance requirements have been met;
- For involuntary termination (not for cause), unvested options are pro-rated; and
- For change of control, the plan assumes the performance requirements have been met.

We pro-rate based on active employment during the vesting period and we treat the pro-rated options as time vested.

In addition, the executive officer will receive:

- Up to a maximum of $20,000 for financial or career counseling assistance.
- An amount in cash equal to the value of all of such executive officer's accrued and unpaid vacation pay.
- Annual flexible perquisite, flex credit allowance and savings plan matching contributions over the severance period (2 years).

Mr. Harper is subject during his employment (and indefinitely thereafter with regard to disclosure of confidential information) to restrictions on (1) any practice or business in competition with Enbridge or its affiliates and (2) disclosure of the confidential information of Enbridge or its affiliates.

In the event of a termination that would result in severance benefits, Enbridge would owe incremental benefits to Mr. Harper with a value of approximately $4 million. Such amounts assume that termination was effective as of December 31, 2014, and as a result include amounts earned through such time and are estimates of the amounts which would be paid out to Mr. Harper upon termination under such circumstances. The actual amounts to be paid out can only be determined at the time of such executive's separation from Enbridge.

Director Compensation

As a partnership, we are managed by our General Partner. The board of directors of our General Partner performs for us the functions of a board of directors of a business corporation. We are allocated 100% of the director compensation of these board members. Enbridge employees who are members of the boards of directors of our General Partner do not receive any additional compensation for serving in those capacities. Effective December 31, 2014, Terrance L. McGill resigned as a member of the board of directors of the General Partner.

Directors of our General Partner who are not officers or employees of our General Partner or its affiliates receive compensation as "non-employee directors," which is an annual retainer value equal to $115,000 payable in cash. The chairman of the board of directors of our General Partner receives an additional annual cash retainer equal to $20,000. In addition, the chair of the Audit, Finance and Risk Committee receives an additional annual cash retainer equal to $15,000. The chair of the Special Committee receives $5,000 per assignment.

The Corporate Governance Guidelines provide an expectation that independent directors will hold a personal investment in us of at least two times the annual board retainer, which, based on the current annual retainer would equal $230,000 (i.e., 2 X $115,000 = $230,000). Directors would be expected to achieve the foregoing level of equity ownership by the later of October 10, 2018 or five years from the date he or she became a director. None of our independent directors have been a director for five years. Therefore, we consider that all of the directors are in compliance.

DIRECTOR COMPENSATION

Name (a)	Fees Earned or Paid in Cash[(1)] ($) (b)
Dan A. Westbrook *Chairman of the Board*	104,250
J. Herbert England *Audit, Finance & Risk Committee Chairman*	100,500
John A. Crum	112,503
James G. Ivey	112,503
Edmund P. Segner III	119,003
C. Gregory Harper, Mark A. Maki and Terrance L. McGill[(2)]	—

(1) First quarter 2014 retainer fees for each of Messr. Crum, Ivey and Segner were prorated from their election on February 10, 2014. The first quarter 2014 retainer fees for Messrs. Westbrook and England were paid at the end of 2013. Therefore, the amounts reflected above include payments from February 10, 2014 through December 31, 2014.

(2) These directors are also employees of Enbridge or its subsidiaries and thus do not receive any compensation as a director in addition to their standard compensation as an employee of Enbridge or its subsidiaries.

Each director is indemnified for his or her actions associated with being a director to the fullest extent permitted under Delaware law and will be reimbursed for all expenses incurred in attending to his or her duties as a director.

COMPENSATION REPORT OF THE BOARD OF DIRECTORS

The Board of Directors of Midcoast Holdings, L.L.C has reviewed and discussed the Compensation Discussion and Analysis section of this report with management and, based on that review and discussion, has recommended that the Compensation Discussion and Analysis be included in this report.

/s/ C. Gregory Harper

C. Gregory Harper
President (Principal Executive Officer) and Director

/s/ J. Herbert England

J. Herbert England
Director

/s/ Dan A. Westbrook

Dan A. Westbrook
Director

/s/ John A. Crum

John A. Crum
Director

/s/ Mark A. Maki

Mark A. Maki
Director

/s/ Edmund P. Segner III

Edmund P. Segner III
Director

/s/ James G. Ivey

James G. Ivey
Director

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

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information as of February 17, 2015 with respect to persons known to us to be the beneficial owners of more than 5% of any class of the Partnership's units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent of Class
Enbridge Energy Partners, L.P.[1]	Class A common units	1,335,056	5.9
1100 Louisiana St., Suite 3300	Subordinated units	22,610,056	100.0
Houston, TX 77002	General Partner units	922,859	100.0
OppenheimerFunds Inc.[2]	Class A common units	4,468,744	19.8
225 Liberty Street			
New York, NY 10281-1008			
Kayne Anderson Capital Advisors, L.P.	Class A common units	3,791,223	16.8
1800 Avenue of the Stars			
Third Floor			
Los Angeles, CA 90067			
Oppenheimer SteelPath MLP Income Fund[3]	Class A common units	3,100,729	13.7
6803 S. Tucson Way			
Centennial, CO 80112			
Clearbridge Investments, LLC	Class A common units	2,283,460	10.1
620 8th Avenue			
New York, NY 10018			
Neuberger Berman L.L.C.[4]	Class A common units	862,300	3.8
605 Third Avenue			
New York, NY 10158			

(1) As of February 13, 2014, EEP directly held 1,335,056 Class A common units and 22,610,056 Subordinated units; 922,859 general partner units were held by Midcoast Holdings, a wholly owned subsidiary of EEP.

(2) OppenheimerFunds Inc. reported shared voting and dispositive power as to the 4,468,744 Class A common units in an amendment to its Schedule 13G, filed February 5, 2015.

(3) Oppenheimer SteelPath MLP Income Fund reported sole voting power and shared dispositive power as to the 3,100,729 Class A common units.

(4) Neuberger Berman Group L.L.C. reported shared voting power as to 858,463 Class A common units and shared dispositive power as to 862,300 Class A common units in its Schedule 13G, filed February 12, 2015.

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 13, 2015 respect to each class of our units beneficially owned by the NEOs and directors and executive officers of Midcoast Holdings as a group:

	Midcoast Energy Partner, L.P.		
Name	**Title of Class**	**Number of of Class [1]**	**Percent of Class**
Dan A. Westbrook[2]	Class A common units	11,000	*
John A. Crum	Class A common units	12,000	*
J. Herbert England	Class A common units	5,000	*
C. Gregory Harper	Class A common units	5,620	*
James G. Ivey	Class A common units	6,000	*
Mark A. Maki	Class A common units	19,000	*
Terrance L. McGill[3]	Class A common units	25,000	*
Edmund P. Segner III	Class A common units	12,000	*
Janet L. Coy	Class A common units	1,000	*
John A. Loiacono	Class A common units	10,000	*
Stephen J. Neyland[4]	Class A common units	4,700	*
Kerry C. Puckett	Class A common units	8,000	*
All executive officers, directors and nominees as a group (18 persons)	Class A common units	97,420	*

* Less than 1%.

(1) Unless otherwise indicated, each beneficial owner has sole voting and investment power with respect to all of the Class A common units attributed to him or her.

(2) Mr. Westbrook is the indirect owner of these units, which are held by the Westbrook Trust.

(3) Mr. McGill retired on December 31, 2014 and is no longer an officer or director of our General Partner.

(4) The 4,700 Listed Shares beneficially owned by Mr. Neyland are held in a Family Trust for which Mr. Neyland is a co-trustee as well as a beneficiary.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table provides information as of December 31, 2014 with respect to Class A common units that may be issued under the 2014 Midcoast Energy Partners, L.P. Long-Term Incentive Plan, or our LTIP:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[1]	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans[2]
Equity compensation plans approved by security holders	N/A	N/A	3,750,000
Equity compensation plans not approved by security holders	—	—	—
Total			3,750,000

(1) We have not previously granted equity incentive awards in us to any person pursuant to the LTIP

(2) Reflects the Class A common units available for issuance pursuant to the LTIP

Item 13. Certain Relationships and Related Transactions, and Director Independence

Certain Relationships and Related Transactions

As of December 31, 2014, Enbridge Energy Partners owned 1,335,056 Class A common units and 22,610,056 subordinated units representing a 51.9% limited partner interest in us. In addition, our General Partner owns 922,859 general partner units representing a 2% general partner interest in us.

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties. For further discussion of these and other related party transactions, refer to refer to Item 8. *Financial Statements and Supplementary Data*, under Note 12. *Related Party Transactions*.

Review, Approval or Ratification of Transactions with Related Persons

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our General Partner as appropriate. The board of directors then determines whether it is advisable to constitute a special committee of independent directors to evaluate the proposed transaction. If a special committee is appointed, the committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the special committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair to us and all of our unitholders.

Potential transactions with related persons that are not financially significant so as to require review by the board of directors are disclosed to the President of our General Partner and reviewed for compliance with the Enbridge Statement on Business Conduct. The President may also consult with legal counsel in making such determination. If a related person transaction occurred and was later found not to comply with the Statement on Business Conduct, the transaction would be reported to the board of directors for further review and ratification or remedial action.

The Enbridge Statement of Business Conduct sets forth policies and procedures for the review and approval of certain transactions with persons affiliated with us.

During 2014, we had the following "related person" transactions (as the term is defined in Item 404 of Regulation S-K):

- An affiliate of Enbridge that provides employee services to the Partnership continued a previously existing employment relationship with Ryan McGill, the son of Terrance L. McGill, one of the named executive officers and a former member of the Board of Directors. Mr. McGill is employed in our Houston office as a Gas Supply Representative. During 2014, he received total cash compensation of \$115,482.04 and benefits estimated at approximately 32% of his base compensation for a total of \$145,663.81.

Director Independence

For a discussion of director independence, see Item 10. *Directors, Executive Officers and Corporate Governance.*

Item 14. Principal Accountant Fees and Services

The following table sets forth the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP, our principal independent auditors, for each of our last two fiscal years.

	For the year ended December 31,	
	2014	2013[3]
Audit fees[1]	$2,291,000	$1,452,000
Tax fees[2]	225,000	219,000
Total	$2,516,000	$1,671,000

(1) Audit fees consist of fees billed for professional services rendered for the audit of our consolidated financial statements, reviews of our interim consolidated financial statements, audits of various subsidiaries for statutory and regulatory filing requirements and our debt and equity offerings.

(2) Tax fees consist of fees billed for professional services rendered for federal and state tax compliance for Partnership tax filings and unitholder K-1's.

(3) The 2013 Audit fees represents fees for the initial audit year.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit, Finance, and Risk Committee of Midcoast Holdings board of directors; however, services up to $50,000 may be approved by the Chairman of the Audit, Finance, and Risk Committee, under the board of directors' delegated authority. All services in 2014 were approved by the Audit, Finance, and Risk Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as a part of this report:

(1) *Financial Statements.*

The following financial statements and supplementary data are incorporated by reference in Part II, Item 8. *Financial Statements and Supplementary Data* of this Form 10-K.

a. Report of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

b. Consolidated Statements of Income for the years ended December 31, 2014, 2013 and 2012.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2014, 2013 and 2012.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012.

e. Consolidated Statements of Financial Position as of December 31, 2014 and 2013.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2014, 2013 and 2012.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

All schedules have been omitted because they are not applicable, the required information is shown in the consolidated financial statements or Notes thereto or the required information is immaterial.

(3) *Exhibits.*

Reference is made to the "Index of Exhibits" following the signature page, which is hereby incorporated into this Item.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MIDCOAST ENERGY PARTNERS, L.P.
(Registrant)

By: Midcoast Holdings, L.L.C.,
as General Partner

By: /s/ C. Gregory Harper

C. Gregory Harper
President
(Principal Executive Officer)

Date: February 18, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 18, 2015 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ C. Gregory Harper

C. Gregory Harper
President (Principal Executive Officer) and Director

/s/ Mark A. Maki

Mark A. Maki
Senior Vice President and Director

/s/ Stephen J. Neyland

Stephen J. Neyland
Vice President—Finance
(Principal Financial Officer)

/s/ Noor S. Kaissi

Noor S. Kaissi
Controller
(Principal Accounting Officer)

/s/ J. Herbert England

J. Herbert England
Director

/s/ Dan A. Westbrook

Dan A. Westbrook
Director

/s/ John A. Crum

John A. Crum
Director

/s/ James G. Ivey

James G. Ivey
Director

/s/ Edmund P. Segner III

Edmund P. Segner III
Director

Index of Exhibits

Each exhibit identified below is filed as a part of this annual report. Exhibits included in this filing are designated by an asterisk("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report pursuant to Item 15(b) of Form 10-K.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Midcoast Energy Partners, L.P., dated May 30, 2013 (incorporated by reference to Exhibit 3.1 of our Registration Statement on Form S-1 (Registration No. 333-189341), initially filed on June 14, 2013, as amended).
3.2	First Amended and Restated Agreement of Limited Partnership of Midcoast Energy Partners, L.P. dated November 13, 2013 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed on November 18, 2013).
4.1	Specimen Unit Certificate for the Class A Common Units (included as Exhibit A to the Form of First Amended and Restated Agreement of Limited Partnership of the Registrant) (incorporated herein by reference to Appendix A of the First Amended and Restated Agreement of Limited Partnership of Midcoast Energy Partners, L.P. under Exhibit 3.1 of our Current Report on Form 8-K, filed on November 18, 2013).
10.1	Contribution, Conveyance and Assumption Agreement by and among Midcoast Energy Partners, L.P., Enbridge Energy Partners, L.P., Midcoast Holdings, L.L.C., Midcoast Operating L.P. and Midcoast OLP GP, L.L.C. dated as of November 13, 2013, (incorporated by reference to Exhibit 10.1 of our of our Current Report on Form 8-K, filed on November 18, 2013).
10.2	Omnibus Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., Midcoast Holdings, L.L.C., Enbridge Energy Partners, L.P. and Enbridge Inc. (incorporated by reference to Exhibit 10.2 of our of our Current Report on Form 8-K, filed on November 18, 2013).
10.3	Credit Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., as Co-Borrower, Midcoast Operating L.P., as Co-Borrower, the subsidiary guarantors party thereto, Bank of America, N.A., as Administrative Agent, Letter of Credit Issuer, Swing Line Lender and lender, and each of the other lenders party thereto (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed on November 18, 2013).
10.4	Amendment No. 1 to Credit Agreement and Extension Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the subsidiary guarantors party thereto, the lenders party thereto and Bank of America, N.A., as administrative agent for the lenders (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on October 6, 2014).
10.5	Note Purchase Agreement by and among Midcoast Energy Partners, L.P. and the purchasers named therein, dated as of September 30, 2014 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on October 6, 2014).
10.6	Guaranty Agreement dated as of September 30, 2014, made by each guarantor in favor of the purchasers and other holders from time to time of the Notes in the Note Purchase Agreement (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on October 6, 2014).
10.7	Intercorporate Services Agreement, dated as of November 13, 2013, by and between EEP and Midcoast Energy Partners, L.P. (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on November 18, 2013).

Exhibit Number	Description
10.8	Financial Support Agreement, dated as of November 13, 2013, by and between Midcoast Operating, L.P. and EEP (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on November 18, 2013).
10.9	Amended and Restated Allocation Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., Enbridge Inc., EEP and Enbridge Income Fund Holdings Inc., (incorporated by reference to Exhibit 10.6 of our Current Report on Form 8-K, filed on November 18, 2013).
10.10	Amended and Restated Agreement of Limited Partnership of Midcoast Operating, L.P., dated as of November 13, 2013 (incorporated by reference to Exhibit 10.8 of our Current Report on Form 8-K, filed on November 18, 2013).
10.11	Subordination Agreement dated November 13, 2013 by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., other credit parties from time to time party there to, Enbridge Energy Partners, L.P., and Bank of America, N.A. (incorporated by reference to Exhibit 10.9 of our Quarterly Report on Form 10-Q, filed on December 20, 2013).
10.12	Subordination Agreement dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., other obligors from time to time party thereto, Enbridge Energy Partners, L.P., and certain of its subsidiaries and affiliates from time to time party thereto in favor of the holders from time to time of the Notes in the Note Purchase Agreement (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed on October 6, 2014).
10.13	Amended and Restated Subordination Agreement, dated as of September 30, 2014, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the other credit parties from time to time party thereto and Enbridge Energy Partners, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on October 6, 2014).
+10.14	Executive Employment Agreement, entered into February 11, 2014, between C. Gregory Harper, the Executive, and Enbridge Employee Services, Inc., effective January 30, 2014 (incorporated by reference to our Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 18, 2014).
10.15	Form of Long-Term Incentive Plan of Midcoast Energy Partners, L.P. (incorporated by reference to Exhibit 10.3 to our Registration Statement on Form S-1 (Registration No. 33-189341), initially filed on June 14, 2013, as amended.)
10.16	Purchase and Sale Agreement by and between Enbridge Energy Partners, L.P. and Midcoast Energy Partners, L.P. dated as of June 18, 2014 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 19, 2014).
*21.1	Subsidiaries of the Registrant.
*23.1	Consent of PricewaterhouseCoopers LLP.
*31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.

Exhibit Number	Description
*101.SCH	XBRL Taxonomy Extension Schema Document.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Midcoast Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, C. Gregory Harper, certify that:

1. I have reviewed this Annual Report on Form 10-K of Midcoast Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2015

By: /s/ C. Gregory Harper

C. Gregory Harper

President
(Principal Executive Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Neyland, certify that:

1. I have reviewed this Annual Report on Form 10-K of Midcoast Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2015

By: /s/ Stephen J. Neyland
Stephen J. Neyland
Vice President, Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.1

CERTIFICATE OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Executive Officer of Midcoast Holdings, L.L.C., as general partner of Midcoast Energy Partners, L.P., hereby certifies that our Annual Report on Form 10-K for the fiscal year ended December 31, 2014 (the "Annual Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: February 18, 2015

By: /s/ C. Gregory Harper
C. Gregory Harper
President
(Principal Executive Officer)
Midcoast Holdings, L.L.C. (as the General Partner)

Exhibit 32.2

CERTIFICATE OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Financial Officer of Midcoast Holdings, L.L.C., as general partner of Midcoast Energy Partners, L.P., hereby certifies that our Annual Report on Form 10-K for the fiscal year ended December 31, 2014 (the "Annual Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of Midcoast Energy Partners, L.P.

Date: February 18, 2015

By: /s/ Stephen J. Neyland
Stephen J. Neyland
Vice President, Finance
(Principal Financial Officer)
Midcoast Holdings, L.L.C. (as the General Partner)