ENBRIDGE ENERGY PARTNERS LP
Form 10-K
February 18, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2013

or

¨ **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 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**39-1715850**
(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 x 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 x

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

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

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 x	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 x

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, or the average bid and asked price of such common equity, as of June 30, 2013, was $6,330,149,823.

As of February 14, 2014 the registrant has 254,208,428 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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In this report, unless the context requires otherwise, references to we, us, our or the Partnership are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our General Partner.

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 the Partnership s 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 crude oil, liquid petroleum, natural gas and NGLs, including the rate of development of the Alberta Oil Sands; (2) our ability to successfully complete and finance expansion projects; (3) the effects of competition, in particular, by other pipeline systems; (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, including those related to Line 6B and any additional fines and penalties assessed in connection with the crude oil release on that line; (6) changes in or challenges to our tariff 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 and our subsequently filed Quarterly Reports on Form 10-Q, 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.enbridgepartners.com).

Glossary

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

AEDC	Allowance for equity during construction
AFUDC	Allowance for funds used in construction
Alberta Clipper Pipeline	A 36-inch pipeline that runs from the Canadian international border near Neche, North Dakota to Superior, Wisconsin on our Lakehead system
Amended EDA	Amended and Restated Equity Distribution Agreement
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
CAPP	Canadian Association of Petroleum Producers, a trade association representing a majority of our Lakehead system s customers
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CAD	Amount denominated in Canadian dollars
CWA	Clean Water Act
DOT	United States Department of Transportation
EA interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the Eastern Access Projects
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
Eastern Access Joint Funding Agreement	The funding agreement between Enbridge Energy Partners, L.P. (the Partnership) and Enbridge Energy Company, Inc. (the General Partner) to provide joint funding for the Eastern Access Projects
Eastern Access Projects	Multiple expansion projects that will provide increased access to refineries in the United States Upper Midwest and in Canada in the provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States.
EDA	Equity Distribution Agreement
EES	Enbridge Employee Services Inc., a subsidiary of our General Partner
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.
Enbridge system	Canadian portion of the liquid petroleum mainline system
Enbridge Pipelines	Enbridge Pipelines Inc.
EP Act	Energy Policy Act of 1992
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
FSM	Facilities Surcharge Mechanism
General Partner	Enbridge Energy Company, Inc., the general partner of the Partnership
ICA	Interstate Commerce Act
ISDA®	International Swaps and Derivatives Association, Inc.
Lakehead system	United States portion of the liquid petroleum mainline system

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LIBOR	London Interbank Offered Rate British Bankers Association s average settlement rate for deposits in United States dollars
Light Oil Market Access Program	Several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Project, enhance Enbridge s Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries
M3	Cubic meters of liquid = 6.2898105 Bbl
Mainline Expansion Joint Funding Agreement	The funding agreement between Enbridge Energy Partners, L.P. (the Partnership) and Enbridge Energy Company, Inc. (the General Partner) to provide joint funding for the U.S. Mainline Expansion projects
Mainline system	The combined liquid petroleum pipeline operations of our Lakehead system and the Enbridge system, which is 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
MDNRE	Michigan Department of Natural Resources and Environment
ME interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the U.S. Mainline Expansion projects
MEP	Midcoast Energy Partners, L.P.
Midcoast Operating	Midcoast Operating, L.P., the operating subsidiary of MEP
MLP	Master Limited Partnership
MMBtu/d	Million British Thermal units per day
MMcf/d	Million cubic feet per day
Mid-Continent system	Crude oil pipelines and storage facilities located in the Mid-Continent region of the United States and includes the Cushing tank farm and Ozark pipeline
NEB	National Energy Board, a Canadian federal agency that regulates Canada s energy industry
NGA	Natural Gas Act
NGL or NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act
North Dakota system	Liquids petroleum pipeline gathering system and common carrier pipeline in the Upper Midwest United States that serves the Bakken formation within the Williston basin
North Texas system	Natural gas gathering and processing assets located in the Fort Worth basin serving the Barnett Shale area
NSPS	New Source Performance Standards
NTSB	National Transportation Safety Board
NYMEX	The New York Mercantile Exchange where natural gas futures, options contracts and other energy futures are traded
NYSE	New York Stock Exchange
OLP	Enbridge Energy, Limited Partnership, also referred to as the Lakehead Partnership
OPA	Oil Pollution Act
PADD	Petroleum Administration for Defense Districts
PADD I	Consists of Connecticut, Delaware, District of Columbia, Florida, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia and West Virginia
PADD II	Consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin

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PADD III	Consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas
PADD IV	Consists of Colorado, Idaho, Montana, Utah and Wyoming
PADD V	Consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington
Partnership Agreement	Fourth Amended and Restated Agreement of Limited Partnership of Enbridge Energy Partners, L.P.
Partnership	Enbridge Energy Partners, L.P. and its consolidated subsidiaries
Phase 5 & 6	Expansion Programs on our North Dakota system
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES of 2006	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006
PPI-FG	Producer Price Index for Finished Goods
PSA	Pipeline Safety Act
SAGD	Steam assisted gravity drainage
SEC	United States Securities and Exchange Commission
SEP II	System Expansion Program II, an expansion program on our Lakehead system
Series AC interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the Alberta Clipper Pipeline
Series LH interests	Partnership interests of the OLP related to all the assets, liabilities and operations of the Lakehead System, excluding those designated by the Series AC interests
Southern Access	Southern Access Pipeline, a 42-inch pipeline that runs from Superior, Wisconsin to Flanagan, Illinois on our Lakehead system
Suncor	Suncor Energy Inc., an unrelated energy company
Syncrude	Syncrude Canada Ltd., an unrelated energy company
Synthetic crude oil	Product that results from upgrading or blending bitumen into a crude oil stream, which can be readily refined by most conventional refineries
Tariff Agreement	A 1998 offer of settlement filed with the FERC
Terrace Surcharge	Terrace expansion program, an expansion program on our Lakehead system
TSX	Toronto Stock Exchange
U.S. GAAP	United States Generally Accepted Accounting Principles
U.S. Mainline Expansion projects	Multiple projects that will expand access to new markets in North America for growing production from western Canada and the Bakken Formation
WCSB	Western Canadian Sedimentary Basin

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PART I

Item 1. Business

OVERVIEW

In this report, unless the context requires otherwise, references to we, us, our, or the Partnership are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our General Partner. We are a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transportation and marketing assets in the United States of America. Our Class A common units are traded on the New York Stock Exchange, or NYSE, under the symbol EEP.

The following chart shows our organization and ownership structure as of December 31, 2013. The ownership percentages referred to below illustrate the relationships between us, Enbridge Energy Management, L.L.C., referred to as Enbridge Management, our General Partner and Enbridge and its affiliates:

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We were formed in 1991 by our General Partner, to own and operate the Lakehead system, which is 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, referred to as the Mainline system. A subsidiary of Enbridge owns the Canadian portion of the Mainline system. Enbridge is a leading provider of energy transportation, distribution and related services in North America and internationally. Enbridge is the ultimate parent of our General Partner.

We are a geographically and operationally diversified partnership consisting of interests and assets that provide midstream energy services. As of December 31, 2013, our portfolio of assets included the following:

- Approximately 6,350 miles of crude oil gathering and transportation lines and 34 million barrels, or MMBbl, of crude oil storage and terminaling capacity;

- Approximately 11,600 miles of natural gas gathering and transportation lines and approximately 226 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 580-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;

- 21 active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, with a combined capacity of approximately 2.0 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 1.1 Bcf/ds;

- Approximately 570 compressors with approximately 816,000 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;

- Approximately 250 transport trucks, 300 trailers and 205 railcars for transporting NGLs; and

- Marketing assets that provide natural gas supply, transmission, storage and sales services.

Enbridge Management is a Delaware limited liability company that was formed in May 2002 to manage our business and affairs. Under a delegation of control agreement, our General Partner delegated substantially all of its power and authority to manage our business and affairs to Enbridge Management. Our General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management is the sole owner of a special class of our limited partner interests, which we refer to as i-units.

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BUSINESS STRATEGY

Our primary objective is to provide stable and sustainable cash distributions to our unit holders, while maintaining a relatively low-risk investment profile. Our business strategies focus on creating value for our customers, which we believe is the key to creating value for our investors. To accomplish our objective, we focus on the following key strategies:

1. Operational excellence

   We will continue to focus on safety, environmental integrity, innovation and effective stakeholder relations. We strive to operate our existing infrastructure to provide flexibility for our customers and ensure system capacity is reliable and available when required.

2. Expanding our core asset platforms

   We intend to develop energy transportation assets and related facilities that are complementary to our existing systems. This will be achieved primarily through organic growth. Our core businesses provide plentiful opportunities to achieve our primary business objectives.

3. Project Execution

   Our Major Projects group is committed to executing and completing projects safely, on time and on budget. These include new builds, organic growth and expansion projects.

4. Developing new asset platforms

   We plan to develop and acquire new assets to meet customer needs by expanding capacity into new markets with favorable supply and demand fundamentals.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses while remaining focused on the safe, reliable, effective and efficient operation of our current assets. We are well positioned to pursue opportunities for accretive acquisitions in or near the areas in which we have a competitive advantage. We intend to execute our growth strategy by maintaining a capital structure that balances our outstanding debt and equity in a manner that sustains our investment grade credit rating.

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Liquids

The map below presents the locations of our current Liquids systems assets and projects being constructed. The map also depicts some Liquids Pipelines assets owned by Enbridge and projects being constructed to provide an understanding of how they interconnect with our Liquids systems.

Our business strategy provides an overview of North American production that is transported on our pipelines and the projects that we are pursuing to connect the growing supplies of this production to key refinery markets in the United States.

In 2013, we transported production from the Western Canadian Sedimentary Basin, or WCSB, and the North Dakota Bakken. Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2013 from the United States Department of Energy s Energy Information Administration, or EIA, Canada supplied approximately 2.5 million barrels per day, or bpd, of crude oil to the United States, the largest source of United States imports. Over half of the Canadian crude oil moving into the United States was transported on the Mainline system. The Canadian Association of Petroleum Producers (CAPP), in their June 2013 forecast of future production from the Alberta oil sands, continued to expect steady growth in supply during the next two decades with an additional 4.2 million Bpd of incremental supply available for transportation by 2030, based on a subset of currently approved applications and announced expansions. We are well positioned to deliver growing volumes of crude oil that are expected from the WCSB to our existing as well as new markets.

North Dakota, Montana and Saskatchewan, Canada continued to experience tremendous growth in the development of crude oil, natural gas, and NGLs from the Bakken and Three Forks formations. The latest data released in 2013 by the United States Geological Survey estimated that technically recoverable oil in the Bakken and Three Forks formation in North Dakota have doubled to approximately 7.4 billion barrels.

Along with Enbridge, we are actively working with our customers to develop transportation options that will alleviate capacity constraints in addition to providing access to new markets in the United States. Our market strategy is to provide safe, timely, economic, competitive, integrated transportation solutions to connect growing supplies of production to key refinery markets in the United States. Our strategy also includes further development of our transportation infrastructure to address the growing production of North Dakota and western Canada light oil. Together, our existing and future plans advance our vision of being North America s first choice for liquids deliveries.

Since last year, we and Enbridge have announced multiple upstream and downstream new build and expansion projects that will provide increased market access for producers to refineries in the United States Upper Midwest, eastern Canada, and the United States Gulf Coast refining centers. The Sandpiper project, as discussed below, complements our already announced Eastern Access and Light Oil Market Access initiatives.

Eastern Access

Our joint Eastern Access initiative is comprised of expansion projects that provide both heavy & light producers with increased market access to the eastern Midwest and eastern Canadian refining markets. We have entered into a joint funding agreement with Enbridge for the expansion of Line 5 and Spearhead North (or Line 62) while also replacing Line 6B. Completed earlier in 2013, the Line 5 expansion project has increased the line s capacity between Superior, Wisconsin and Sarnia, Ontario by 50,000 Bpd. Additionally, ours and Enbridge s Line 6B replacement project will replace 210 miles of existing pipeline and add 260,000 bpd day of capacity into the Sarnia refining center. The in-service date for the Line 6B replacement project is Q1 2014 for the Griffith, Indiana to Stockbridge, Michigan segment and Q3 2014 for the segment from Ortonville, Michigan to Sarnia, Ontario. Additionally, the joint funded Line 62) expansion has brought an additional 105,000 bpd of capacity from our Flanagan terminal into our Griffith terminal in November 2013.

To complement these jointly funded expansions, Enbridge also announced plans to increase connectivity to the Toledo and eastern Canadian refining markets, both relying on our Lakehead system for additional volumes. Enbridge has already received regulatory approvals to reverse Line 9A and has undergone a regulatory process for reversing Line 9B. Enbridge s Line 9A reversal was completed in 2013, adding 240,000 bpd of east-flowing capacity into Enbridge s Westover, Ontario terminal. Subject to Enbridge receiving a favorable regulatory decision, Line 9B could go into service in the latter half of 2014 providing 300,000 bpd of pipeline capacity to the Montreal refining market. The Enbridge-funded Toledo Pipeline Twin will add 80,000 bpd of new capacity into the Toledo refining market. Both Enbridge-funded market access projects will access volumes from our Lakehead system.

Light Oil Market Access

To accommodate the significant and sustainable growth in the Bakken resource play, we, along with our 37.5% funding partner and anchor shipper, Marathon Petroleum Corporation, are proposing to construct the approximately 600-mile Sandpiper pipeline. The pipeline will carry an additional 225,000 barrels of oil to Clearbrook, Minnesota and 375,000 barrels a day to our Superior terminal located in north western Wisconsin. The Sandpiper pipeline is a key pipeline that will supply numerous Enbridge and Partnership funded downstream pipeline expansions and new builds. We, along with Enbridge, will twin Line 62 which will add 570,000 bpd of new pipeline capacity into Enbridge s Hartsdale terminal by Q3 2015. Then we, along with Enbridge, will expand the replaced Line 6B to 570,000 in early 2016. The Enbridge-funded Southern Access Extension and Line 9 reversal and expansion projects will also increase the markets accessed by Lakehead and drive volumes through the Lakehead system. Enbridge s 165-mile 24-inch diameter Southern Access Extension pipeline from Flanagan, IL to Patoka, IL will add 300,000 bpd into the Patoka terminal in 2015.

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In North Dakota, oil production levels rose to approximately 932,000 bpd during September 2013 which is an approximate 21% increase since the month of December 2012. Capitalizing on this growth, we continue to develop complementary rail options to access key refinery markets for the Bakken region as pipelines develop. Our Berthold Rail Project will allow Bakken crude oil further access to markets that are not connected to the major Midwest pipelines. For further discussion on these projects see BUSINESS SEGMENTS *North Dakota System* in this Item.

A key competitive strength of ours is our relationship with Enbridge. Enbridge has announced two additional major United States Gulf Coast market access pipeline projects that will pull more volume through the Lakehead system when completed.

Enbridge s Flanagan South Pipeline, a twinning of its existing Spearhead system, will transport higher volumes from Flanagan, Illinois into the Cushing hub. The 36-inch diameter pipeline will have an initial capacity of approximately 585,000 Bpd, and subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014.

Seaway Crude Pipeline System In 2011, Enbridge completed the acquisition of a 50% interest in the Seaway Crude Pipeline System, or Seaway. Seaway was a 670-mile pipeline that includes a 500-mile, 30-inch pipeline long-haul system from Freeport, Texas to Cushing, Oklahoma, as well as a Texas City Terminal and Distribution System that serves refineries in Houston and Texas City areas. In March 2012, the direction of the 500-mile Seaway pipeline was reversed to enable it to transport oil from Cushing, Oklahoma to the United States Gulf Coast, providing capacity of 150,000 bpd. Further pump station additions and modifications, which were completed in January 2013, increased capacity up to 400,000 bpd, depending upon the mix of light and heavy grades of crude oil. Enbridge together with Enterprise is also twinning the existing Seaway pipeline which will add 450,000 bpd of capacity to the system by mid-2014. In addition, in March 2012, plans were announced to construct an 85-mile pipeline from Enterprise Product s ECHO crude oil terminal southeast of Houston to the Port Arthur/Beaumont, Texas refining center. When completed, this is expected to provide 750,000 Bpd of capacity by mid-2014.

Natural Gas

The map below presents the locations of our current Natural Gas systems assets and projects being constructed, including joint ventures. These assets are owned by MEP and its subsidiaries. MEP is a Delaware limited partnership we formed to serve as our primary vehicle for owning and growing our natural gas and NGL midstream business in the United States. MEP completed its initial public offering in November of 2013, but we continue to own all of the equity interests in MEP s general partner, a 52% limited partner interest in MEP and a 61% limited partner interest in MEP s operating subsidiary, Midcoast Operating. This map depicts some assets owned or under development by Enbridge to provide an understanding of how they relate to our Natural Gas systems.

Our natural gas assets are primarily located in Texas and Oklahoma, a region which continues to maintain its status as one of the most active natural gas producing areas in the United States. Our three systems in Texas are located in basins that have experienced active drilling over the last several years. These core basins are known as the East Texas basin, the Fort Worth basin and the Anadarko basin. Our focus has primarily been on developing and expanding the service capability of our existing pipeline systems and acquiring assets with strong growth prospects located in or near the areas we serve or have competitive advantage. We may also target future growth in areas where we can deploy our successful operating strategy to expand our portfolio into other natural gas production regions.

The operations and commercial activities of our gathering and processing assets and intrastate pipelines are integrated to provide better service to our customers. From an operations perspective, our key strategies are to provide safe and reliable service at reasonable costs to our customers and capitalize on opportunities for attracting new customers. From a commercial perspective, our focus is to provide our customers with a greater value for their commodity. We intend to achieve this latter objective by increasing customer access to preferred

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natural gas markets and natural gas liquids, or NGLs. The aim is to be able to move significant quantities of natural gas and NGLs from our Anadarko, North Texas and East Texas systems to the major market hubs in Texas and Louisiana. From these market hubs, natural gas can be used in the local Texas markets or transported to consumers in the Midwest, Northeast and Southeast United States. The primary market hub for NGLs is the fractionation center in Mont Belvieu, Texas, with its access to refineries, petro-chemical plants, export terminals and outbound pipelines.

The long term prospects in our core areas remain favorable, primarily as a result of technological advancements that have enhanced production of natural gas and NGLs from tight sand and shale formations. The reserves and resource potential in all three of our operating basins is substantial. The current price environment has forced producers to focus their drilling efforts on oil, condensate and liquids rich gas, all of which still produce associated gas that needs to be gathered and requires processing to separate the NGLs. When natural gas prices recover to the level that will incentivize producers to drill their lean gas prospects, our core assets are well positioned to gather, treat and transport this gas to market. To address a near term liquids focused environment, we have increased our gas processing capacity, our NGL takeaway capacity, and third party fractionation capacity at major fractionation hubs. Our goal is to offer our customers the ability to gather, process, and transport their liquids to major markets.

Our Natural Gas business also includes trucking, rail and liquids marketing operations that we use to enhance the value of the NGLs produced at our processing plants. Our Natural Gas marketing business provides us with the ability to maximize the value received for the natural gas we transport and purchase by identifying customers with consistent demand for natural gas.

BUSINESS SEGMENTS

We conduct our business through three business segments:

- Liquids;
- Natural Gas; and
- Marketing.

These segments have unique business activities that require different operating strategies. For information relating to revenues from external customers, operating income and total assets for each segment, refer to Note 18. *Segment Information* of our consolidated financial statements beginning on page 204 of this report.

Liquids Segment

Lakehead system

Our Lakehead system consists primarily of crude oil and liquid petroleum common carrier pipelines and terminal assets in the Great Lakes and Midwest regions of the United States. The Lakehead system, together with the Enbridge system in Canada, form the Mainline system, which has been in operation for over 60 years and forms the longest liquid petroleum pipeline system in the world. The Mainline system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada.

Over the past five years, we have completed the largest pipeline expansion program in our history. During the 2008 through 2010 time periods, we completed the Southern Access expansion program, referred to as the Southern Access Pipeline, or Line 61, which increased the capacity of our Mainline system into the Chicago area by 400,000 Bpd and the Alberta Clipper expansion program, referred to as the Alberta Clipper Pipeline, or Line 67, which added 450,000 Bpd of additional capacity into Superior. The Southern Access Pipeline can be expanded further to a total capacity of 1.2 million Bpd with additional pumping station capital. The United States portion of the Alberta Clipper Pipeline can also be further expanded to 800,000 Bpd. Supply from the Bakken play in North Dakota is expected to reach over 800,000 Bpd by 2015 and over 1 million Bpd by 2021. Western Canada oil sands production is expected to grow by 3.3 million Bpd to over 5 million Bpd by 2030. With this production growth, the industry requires more capacity to transport crude oil out of North Dakota and the oil sands regions into the United States Midwest markets and interconnecting transportation hubs. The need for further capacity on our Lakehead system was driven by producers and refiners that have long development timelines and need assurance that adequate pipeline infrastructure will be in place in time to transport the additional production resulting from completion of their projects. Both the Alberta Clipper and Southern Access Pipelines were a direct response to this need.

Our Lakehead system is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission, or FERC. Our Lakehead system spans a distance of approximately 2,200 miles and consists of approximately 5,100 miles of pipe with diameters ranging from 12 inches to 48 inches, and is the primary transporter of crude oil and liquid petroleum from Western Canada to the United States. Additionally, the system has 64 pump station locations with a total of approximately 920,000 installed horsepower and 72 crude oil storage tanks with an aggregate capacity of approximately 14 million barrels. The Mainline system, as a whole, operates in a segregation, or batch mode, allowing the transport of 48 crude oil commodities including light, medium and heavy crude oil (including bitumen, which is a naturally occurring tar-like mixture of hydrocarbons), condensate and NGLs.

Customers. Our Lakehead system operates under month-to-month transportation arrangements with our shippers. During 2013, approximately 47 shippers tendered crude oil and liquid petroleum for delivery through our Lakehead system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Lakehead system. Our customers include integrated oil companies, major independent oil producers, refiners and marketers.

Supply and Demand. Our Lakehead system is well positioned as the primary transporter of Western Canadian crude oil and continues to benefit from the growing production of crude oil from the Alberta Oil Sands, as well as recent development in Tight Oil production in North Dakota. The National Energy Board, or NEB, estimated that total production from the WCSB averaged approximately 3.3 million Bpd in 2013 and 3 million in 2012. Meanwhile, strong production growth from the Bakken formation has increased tight oil available from North Dakota to nearly 780,000 Bpd in 2013, as compared to 600,000 Bpd in 2012. With access to growing supply from the WCSB and Bakken formation, the Lakehead system will remain an important conduit for crude oil to U.S. markets for years to come. Volumes of WCSB crude oil production exceed those from Iraq and Venezuela, key members of the Organization of Petroleum Exporting Countries, or OPEC.

Remaining established reserves from the Alberta Oil Sands as of the end of 2012 were approximately 168 billion barrels according to the Alberta Energy Regulator, or AER. Additionally, remaining established conventional oil reserves in Western Canada were estimated to be approximately 3.4 billion barrels at the end of 2012. Canada s total combined conventional and oil sands estimated proved reserves of approximately 174 billion barrels at the end of 2012 compares with Saudi Arabia s estimated proved reserves of approximately 266 billion barrels.

According to CAPP, an estimated total $359 billion Canadian dollars, or CAD, has been spent on oil sands development from 1997 through 2012. The rate of growth of the Alberta Oil Sands moderated in previous years due to declining demand and commodity prices; however, rising oil prices and demand has led to a rebound in production growth and the announcement of new oil sands projects, as noted in the discussion below. As mentioned above, CAPP s June 2013 Growth Forecast estimates that the future production from the Alberta Oil

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Sands is expected to grow steadily during the next 17 years, with an additional 3.3 million Bpd of incremental production available by 2030.

The near-term growth in crude oil supply comes from the completion and ramp up of major expansion projects at existing synthetic crude oil upgraders and growth of bitumen production from both existing and new Steam Assisted Gravity Drainage, or SAGD, and mining facilities. The 2013 delivered production of four major Alberta Oil Sands producers is detailed as follows:

- Suncor s oil sands production grew to 361,000 Bpd in 2013, up from 324,000 Bpd in 2012 (includes upgraded sweet and sour synthetic crude oil as well as non-upgraded bitumen). Suncor completed Stage 4 expansion at its Firebag project at the end of 2012 and is expecting production from the project to reach 180,000 Bpd in early 2014. Moving forward, the company will continue to focus on developing existing projects such as Mackay River and Firebag as well as other potential in situ growth prospects. Also, as disclosed in a news release during 2013, Suncor has decided to proceed with the Fort Hills oil sands project, which is expected to increase bitumen production by 180,000 Bpd by 2017;

- Syncrude Canada Ltd. s, or Syncrude s, synthetic production in 2013 averaged 267,000 Bpd, which is slightly below production levels from 2012. Syncrude operates five mine trains on its active leases, four of which will be replaced or relocated by the end of 2014 to sustain and improve bitumen production. Plans are in place to coordinate these efforts such that production should not be affected. Syncrude s next expansion is the Stage 3 debottleneck which would increase their current system s synthetic production by approximately 75,000 Bpd. The projected in-service date of the Stage 3 debottleneck has not been established;

- In June 2013, Cenovus began production at Phase E of its Christina Lake Project. Phase E is expected to yield an additional 40,000 Bpd of production and brings the project s production capacity up to 138,800 Bpd at the end of 2013. Construction of Phase F is on schedule for a 2016 startup and preliminary work is underway for subsequent project phases in the coming years. With continued optimizations and expansions, the ultimate capacity of the Christina Lake project is approximately 310,000 Bpd; and

- In Imperial Oil s Kearl oil sands project began operating in April 2013. Initial production will ramp up to approximately 110,000 Bpd unblended by 2015. The project has regulatory approval for up to 345,000 Bpd of production with its additional phases and will be one of Canada s largest oil sands mining operations. Production will be sold as blended bitumen and shipped upstream via Enbridge s Woodland Pipeline.

Over the next two years, a number of individual projects are expected to come on-line that should start to increase the production of unblended bitumen. Other notable projects include Husky s Sunrise, Athabasca Oil Corporation s Hangingstone, ConocoPhillips Surmont and MEG Energy s Christina Lake. Based on the CAPP Production forecast, unblended bitumen production is expected to increase by roughly 177,000 Bpd by the end of 2014 and then increase by an additional 124,000 Bpd by the end of 2015.

Although the crude oil and liquid petroleum delivered through our Lakehead system originates primarily in oilfields in Western Canada, our Lakehead system also receives a portion of its receipts from domestic sources including:

- United States Bakken production at Clearbrook, Minnesota through a connection with our North Dakota system;

- United States production at Lewiston, Michigan; and

- Both United States and offshore production in the Chicago area.

In the coming years, Bakken production is expected to become a major component of the United States domestic supply mix. Estimates from the United States Energy Information Administration expect production to reach 800,000 Bpd by 2015 and over 1 million Bpd by 2021. Other industry experts have production forecasts which are higher.

Based on forecasted growth in Western Canadian crude oil production and completion of upgrader expansions and increased bitumen production, our Lakehead system deliveries are expected to grow beyond the 1.8 million Bpd of actual deliveries in 2013. The ability to increase deliveries and to expand our Lakehead system in the future will ultimately depend upon a number of factors. The investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers expectations of crude oil and natural gas prices, future operating costs, United States demand and availability of markets for produced crude oil. Higher crude oil production from the WCSB should result in higher deliveries on our Lakehead system. Deliveries on our Lakehead system are also affected by periodic maintenance, refinery turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, our Lakehead system.

Refinery configurations and crude oil requirements in the Petroleum Administration for Defense District II, or PADD II, continue to create an attractive market for Western Canadian supply. According to the EIA, 2013 demand for crude oil in PADD II averaged 3.4 million Bpd, a decrease of 68,000 Bpd from 2012. At the same time, production of crude oil within PADD II increased by 244,000 Bpd to 1.4 million Bpd. A significant contributor to the decrease in demand for crude oil in PADD II is a result of BP s Whiting, Indiana refinery undergoing a major upgrade throughout 2013. The project faced delays throughout 2013 but will begin to ramp up production in the first quarter of 2014. The 405,000 Bpd refinery is the largest refinery in the United Stated Midwest. Other Midwest refineries also experienced significant turnarounds during 2013, which contributed to decreases in demand.

Competition. Our Lakehead system, along with the Enbridge system, is the main crude oil export route from the WCSB and a key transportation component for growing Bakken production. WCSB production in excess of Western Canadian demand moves on existing pipelines into PADD II, the Rocky Mountain states (PADD IV), the Anacortes area of Washington state (PADD V), the United States Gulf Coast (PADD III) and to Eastern Canada (Ontario). In each of these regions, WCSB crude oil competes with local and imported crude oil. As local crude oil production declines and refineries demand more imported crude oil, imports from the WCSB should increase.

For 2013, the latest data available shows that PADD II total demand was 3.4 million Bpd while it produced only 1.4 million Bpd and thus imported 2 million Bpd from Canada and other regions of the United States. The 2013 data indicates PADD II imported approximately 1.8 million Bpd of crude oil from Canada, a majority of which was transported on our Lakehead system. The remaining barrels were imported via competitor pipelines from Alberta, and from PADDs III and IV as well as from offshore sources via the United States Gulf Coast. Lakehead system deliveries for 2013 were approximately 24,000 Bpd higher than delivery volumes for 2012. Total deliveries from our Lakehead system averaged 1.8 million Bpd in 2013, meeting approximately 84% of the refinery capacity in the greater Chicago area; 85% of the Minnesota refinery capacity; and 81% of Ontario refinery capacity in 2013.

Considering all of the transportation systems that transport crude oil out of Canada, the Mainline system transported approximately half of all Canadian crude oil imports to the United States in 2013. The Lakehead system mainly serves PADD II market directly and PADD III indirectly. The remaining import volume was transported by systems serving PADD II, PADD IV and PADD V markets.

Given the expected increase in crude oil production from the Alberta Oil Sands over the next 10 years, alternative transportation proposals have been presented to crude oil producers. These proposals and projects

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range from expansions of existing pipelines that currently transport Western Canadian crude oil, to new pipelines and extensions of existing pipelines. Transportation of oil by rail is also a competitive alternative to certain markets. These proposals and projects are in various stages of development, with some at the concept stage and others that are operational. Some of these proposals are in direct competition with our Lakehead system.

Enbridge has filed an application with the NEB for construction of the Northern Gateway Pipeline, which includes both a condensate import pipeline and a petroleum export pipeline. The condensate line would transport imported diluent from Kitimat, British Columbia to the Edmonton, Alberta area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat and would compete with our Lakehead system for production from the Alberta Oil Sands. On December 19, 2013, the National Energy Board s Joint Review Panel released a recommendation to the Canadian Federal Government to approve the project, subject to certain conditions. The Federal Government will render its final decision by July 2014. Given the substantial growth in Western Canadian crude oil supply, this pipeline will provide another market option for Canadian crude oil, an important consideration for Canadian crude oil producers.

We and Enbridge believe that the Southern Access Pipeline, Alberta Clipper Pipeline, the Line 5 expansion, Flanagan South pipeline, the Seaway reversal, Eastern Access Projects, Light Oil Market Access Program and other initiatives to provide access to new markets in the Midwest, Mid-Continent, Eastern Canada and Gulf Coast, offer flexible solutions to future transportation requirements of Western Canadian crude oil producers.

The following provides an overview of other proposals and projects put forth by competing pipeline companies that are not affiliated with Enbridge:

- In 2008, commercial support was announced to construct Keystone XL, a 36-inch crude oil pipeline that will begin at Hardisty and extend down to Cushing and then to Nederland, Texas. The pipeline will connect to existing crude oil pipeline from Hardisty, Alberta to Wood River, Illinois and Patoka. Construction of the pipeline will add an additional 700,000 Bpd of capacity when completed. However, in early 2012, the United States government rejected the necessary permits for the project as it is currently proposed, thereby making the future of this project uncertain. The project sponsor reapplied for the necessary permits, however, the project is still awaiting presidential approval and no timeline has been set for a decision.

- In 2012, strong binding commercial support was announced for the expansion of the existing crude oil pipeline transportation services between Alberta and British Columbia. The expansion is comprised of pipeline facilities that may complete the looping of the pipeline in Alberta and British Columbia, pumping stations, tanks in Edmonton and Burnaby and expansion of the Westridge Marine Terminal, with a planned in service date in early 2017. The pipeline has a current capacity of 300,000 Bpd with expansion alternatives up to 890,000 Bpd. The company submitted a formal application to the National Energy Board on December 16, 2013.

- In 2013, a successful open season was announced for a pipeline project to transport Western Canadian volume to Eastern Canada, confirming strong market support for the pipeline. The project is expected to provide 1.1 million barrels per day of crude oil transportation service from Western to Eastern Canada. The project sponsor has not yet made a formal application for the project; however, they have stated that the expected in service date is in late 2017.

These competing alternatives for delivering Western Canadian crude oil into the United States and other markets could erode shipper support for further expansion of our Lakehead system. They could also affect throughput on and utilization of the Mainline system. However, together, the Lakehead and Enbridge systems offer significant cost savings and flexibility advantages, which are expected to continue to favor the Mainline

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system as the preferred alternative for meeting shipper transportation requirements to the Midwest United States and beyond.

	2013	2012	2011	2010	2009
			(thousands of Bpd)		
United States					
Light crude oil	473	521	473	458	467
Medium and heavy crude oil	948	879	850	841	834
NGL	6	5	4	3	4
Total United States	1,427	1,405	1,327	1,302	1,305
Ontario					
Light crude oil	247	228	220	223	197
Medium and heavy crude oil	76	85	84	57	73
NGL	66	72	69	73	75
Total Ontario	389	385	373	353	345
Total Deliveries	1,816	1,790	1,700	1,655	1,650
Barrel miles (billions per year)	487	480	450	439	423

Mid-Continent system

Our Mid-Continent system, which we have owned since 2004, is located within PADD II and is comprised of our Ozark pipeline and storage terminals at Cushing, Oklahoma; Flanagan, Illinois; and El Dorado, Kansas. Our Mid-Continent system includes over 435 miles of crude oil pipelines and 20.9 million barrels of crude oil storage capacity. This excludes 1.2 million barrels of crude oil storage related to the disposition of the El Dorado storage facility in November 2013. Our Ozark pipeline transports crude oil from Cushing to Wood River, where it delivers to ConocoPhillips Wood River refinery and interconnects with the Woodpat Pipeline and the Wood River Pipeline, each owned by unrelated parties.

The storage terminals consist of 95 individual storage tanks ranging in size from 55,000 to 575,000 barrels. In 2013, 936,000 barrels of incremental shell capacity came into service. Of the 20.9 million barrels of storage shell capacity on our Mid-Continent system, the Cushing terminal accounts for 19.9 million barrels. A portion of the storage facilities are used for operational purposes, while we contract the remainder of the facilities with various crude oil market participants for their term storage requirements. Contract fees include fixed monthly capacity fees as well as utilization fees, which we charge for injecting crude oil into and withdrawing crude oil from the storage facilities.

Customers. Our Mid-Continent system operates under month-to-month transportation arrangements and both long-term and short-term storage arrangements with its shippers. During 2013, approximately 62 shippers tendered crude oil for service on our Mid-Continent system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Average deliveries on the Ozark pipeline system were 202,000 Bpd for 2013 and 223,000 Bpd for 2012.

Supply and Demand. Our Mid-Continent system is positioned to capitalize on increasing near-term demand for crude oil from west Texas and imported crude oil delivered to the United States Gulf Coast, as well as third-party storage demand. In addition, our system is also positioned to capitalize on increasing Canadian imports into the United States. In 2013, PADD II imported 2 million Bpd from outside of the PADD II region. The 2013 data indicates PADD II imported approximately 1.8 million Bpd of crude oil from Canada, a majority of which was transported on our Lakehead system. The remaining barrels of crude oil were imported from PADDs III and IV as well as offshore sources. We expect the demand for local supply to increase and the demand for Canadian crude to stay strong, thus displacing the necessity for other foreign sources.

Competition. Our Ozark pipeline system currently serves an exclusive corridor between Cushing and Wood River. However, refineries connected to Wood River have crude oil supply options available from Canada via our Lakehead system and a third party pipeline. These same refineries also have access to the United States Gulf Coast and foreign crude oil supply through a third-party pipeline system, which is an undivided joint interest pipeline that is owned by unrelated parties. In addition, refineries located east of Patoka with access to crude oil through our Ozark system, also have access to west Texas supply through the West Texas Gulf / Mid-Valley Pipeline systems owned by unrelated parties. Our Ozark pipeline system faces a significant increase in competition after the completion of a competitor s new pipeline from Hardisty to Patoka that came into service in June 2010. Our Ozark pipeline system provides crude oil types and grades that are generally lighter and with lower sulfur relative to that expected to be transported on the new pipeline. To date, our Ozark system has remained full. If a negative impact does occur to the volumes on our Ozark system, we will consider alternative uses for our Ozark system.

In addition to movements into Wood River, crude oil in Cushing is transported to Chicago and El Dorado on third-party pipeline systems. Western Canadian crude oil moving on Spearhead to Cushing continues to increase the importance of Cushing as a terminal and pipeline origination area.

The storage terminals rely on demand for storage service from numerous oil market participants. Producers, refiners, marketers and traders rely on storage capacity for a number of different reasons: batch scheduling, stream quality control, inventory management, and speculative trading opportunities. Competitors to our storage facilities at Cushing include large integrated oil companies and other midstream energy partnerships. Demand for storage capacity at Cushing has remained steady as customers continue to value the flexibility and optionality available with this service. Competition comes from other storage providers with available land and operational facilities in the area. Competition is driven by reliability, quality of service and price.

North Dakota system

Our North Dakota system is a crude oil gathering and interstate pipeline transportation system servicing the Williston Basin in North Dakota and Montana, which includes the highly publicized Bakken and Three Forks formations. Our North Dakota system is approximately 820 miles long, has 23 pump stations, multiple delivery points and storage facilities with an aggregate working storage capacity of approximately 1.3 million barrels, and the gathering pipelines that comprise our North Dakota system collect crude oil from nearly 100 different receipt facilities located throughout western North Dakota and eastern Montana, including more than a dozen third party gathering pipeline connections, and deliver a fungible common stream to a variety of interconnecting pipeline and rail export facilities.

Traditionally, the majority of our pipeline deliveries have been made into interconnecting pipelines at Clearbrook, Minnesota where two other pipelines originate: a third-party pipeline serving Northern Tier refinery markets and our Lakehead system providing further pipeline transportation on the Enbridge system into the Great Lakes, eastern Canada and US Midwest refinery markets that include Cushing, Patoka and other pipelines delivering crude oil to the US Gulf Coast. Today, our North Dakota System continues to serve these traditional markets, but through a series of projects in recent years, we have significantly increased the pipeline and rail export capacity from 80,000 bpd in 2005 to pipeline and rail export capacity of more than 435,000 bpd in 2013 while providing an array of market options and services:

North Dakota Classic Our Phase 5 and Phase 6 Expansions, coupled with a series of other optimization efforts, have increased the pipeline capacity on our traditional North Dakota system to

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approximately 200,000 bpd. The North Dakota Classic system originates at Alexander Station in McKenzie County and terminates at our delivery station at Clearbrook, Minnesota.

Bakken Pipeline Expansion In March 2013, the Bakken Pipeline Expansion Project was placed into service providing an additional 145,000 Bpd of pipeline export capacity from North Dakota. This project, a joint crude oil pipeline expansion project with Enbridge Income Fund Holdings Inc., a partially-owned subsidiary of Enbridge, originates at Berthold, North Dakota and terminates at the Enbridge Mainline in Cromer, Manitoba. Enbridge has secured long term volume commitments from multiple shippers for 100,000 bpd of the 145,000 bpd of capacity, and we will receive 100% of these commitments beginning March of 2014. The terms of these contracts are 5 or 10 years, with the majority of the volumes contracted at 10 years. The Bakken Expansion Project includes a 225,000 bpd expansion of the North Dakota Classic system, the Beaver Lodge Loop Project (BLLP) which provides 425,000 bpd of pipeline capacity into Berthold Station. The BLLP was also placed into service in March 2013.

Bakken Access Program During 2013, we completed the pipeline station expansion projects and third party pipeline connections that were announced in October 2011 as the Bakken Access Program. This Bakken Access program substantially enhanced our gathering capabilities on the North Dakota system and included new facilities at multiple locations accommodating seven third party pipeline connections and the construction of the Little Muddy Station, a new truck delivery / gathering pipeline facility strategically located in Williams County, North Dakota. Our North Dakota system now has the ability to receive more than 300,000 bpd from third party pipelines and more than 500,000 bpd from Enbridge truck and gathering facilities.

Berthold Rail Project In December 2011, we announced Enbridge s first crude oil unit-train rail export facility known as the Berthold Rail Project. With NDPSC approvals received in May 2012 and an initial 10,000 bpd truck-to-rail Phase 1 replaced by the full scale pipe-to-rail operation of 80,000 bpd placed into service in March 2013, Berthold Rail provided our North Dakota customers with an alternative transportation solution to shipper needs in the Bakken region. Today, Berthold Rail feeds Bakken crude to US West Coast, US Gulf Coast and US East Coast markets and provides an excellent complement to the options and market access available to Enbridge customers.

Berthold West In October 2013, Enbridge Storage (North Dakota) placed the first of two 150,000 contract storage tanks into service during 2013 at its new merchant storage facility located adjacent to Berthold Station and the Berthold Rail Project. At Berthold, ESND has an ultimate capacity of 450,000 barrels of total storage capacity, and with similar properties located adjacent to our various facilities across North Dakota, has the opportunity to expand this new line of business to other locations across the Bakken region.

Sandpiper Pipeline Project In November 2013, Enbridge and Marathon Petroleum announced the joint development of the Sandpiper Pipeline Project and the creation of the North Dakota Pipeline Company (NDPL). Sandpiper is an approximate 600-mile pipeline project originating at Beaver Lodge Station near Tioga, North Dakota and terminating at Enbridge s Superior, Wisconsin facilities. The portion from Beaver Lodge to Clearbrook, Minnesota will be a 225,000 bpd 24 pipeline and the portion from Clearbrook to Superior will be a 30 pipeline with 375,000 bpd of capacity.

Customers. Customers of our North Dakota system include refiners of crude oil, producers of crude oil and purchasers of crude oil at the wellhead, such as marketers, that require crude oil gathering and transportation services. Producers range in size from small independent owner/operators to large integrated oil companies.

Supply and Demand. Similar to our Lakehead system, our North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States and the ability of crude oil producers to

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maintain their crude oil production and exploration activities. Due to increased exploration of the Bakken and Three Forks formations within the Williston Basin, the state of North Dakota reported production levels 932,000 Bpd as of September 2013 with projections of exceeding 1 Million Bpd in early 2014. The latest data released in August 2012 by the EIA shows that proved reserves of crude oil in North Dakota were approximately 1.8 billion barrels, a 73% increase from the EIA 2010 Summary. Significant advancements in exploration techniques and an increased understanding of the Williston Basin now suggest the proved reserve base to be substantially higher than what the EIA published.

Competition. Traditional competitors of our North Dakota system include refiners, integrated oil companies, interstate and intrastate pipelines or their affiliates and other crude oil gatherers. Many crude oil producers in the oil fields served by our North Dakota system have alternative gathering facilities available to them or have the ability to build their own assets, including their own rail loading facilities. There are a number of third party pipelines with proposed expansions to increase their capacities to take advantage of the Bakken and Three Forks volume growth: many of these third party pipeline projects are including pipeline connections into our North Dakota system as part of their project scope.

The chief transportation competition to our North Dakota system is rail. Initially considered a niche or alternative form of transportation, rail currently represents more than 75% of the total Bakken crude exported from North Dakota. Rail provides some advantages to pipeline transportation alternatives, but its recent dominance in market share is considered to be primarily driven by extreme price differentials Bakken crudes received vis-à-vis Brent or other non-Cushing based oil markets. Future Enbridge pipeline expansions and enhanced market access to eastern Canadian markets and eastern PADD II are expected to decrease current crude oil price differentials. As pipeline expansion projects create more export capacity from the Bakken, other pipeline projects provide increased access to more refinery markets across the United States, and price differentials return to long term average levels, more North Dakota customers are expected to shift their volumes back to pipelines as the primary transportation option given the economies of scale and other advantages that pipeline transportation enjoy vis-à-vis rail.

Natural Gas Segment

Our natural gas business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities, as well as trucking, rail and liquids marketing operations. 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, using the Texas Express NGL system, we gather NGLs from certain of our facilities for delivery on the Texas Express NGL mainline to Mont Belvieu, Texas. These assets are owned by MEP and its subsidiaries. MEP is a Delaware limited partnership we formed to serve as our primary vehicle for owning and growing our natural gas and NGL midstream business in the United States. MEP completed its initial public offering in November of 2013, but we continue to own all of the equity interests in MEP s general partner, a 52% limited partner interest in MEP and a 61% limited partner interest in MEP s operating subsidiary, Midcoast Operating.

Our natural gas business consists of the following four systems:

Anadarko system: Approximately 3,100 miles of natural gas gathering and transportation pipelines, approximately 58 miles of NGL pipelines, nine active natural gas processing plants, three standby natural gas processing plants and one standby treating plant located in the Anadarko basin.

East Texas system: Approximately 3,900 miles of natural gas gathering and transportation pipelines, approximately 108 miles of NGL pipelines, six active natural gas processing plants, including two

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hydrocarbon dewpoint control facilities, or HCDP plants, eight active natural gas treating plants, three standby natural gas treating plants and one fractionation facility located in the East Texas basin.

North Texas system: Approximately 4,600 miles of natural gas gathering and transportation pipelines, approximately 60 miles of NGL pipelines, six active natural gas processing plants and one standby natural gas processing plant located in the Fort Worth basin.

Texas Express NGL system: A 35% interest in an approximately 580-mile NGL intrastate transportation mainline and a related NGL gathering system that consists of approximately 116 miles of gathering lines.

Customers. Our natural gas pipeline systems serve 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 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 and the prices of natural gas and NGLs. During 2013, NGL prices were at levels higher than prices experienced in the prior year, while natural gas prices were only slightly higher than the prior year. Condensate pricing remained strong and is more closely associated with movements in domestic crude oil prices. As a result of the combination of these pricing dynamics, drilling activity has increased in areas known to have natural gas with high levels of NGL content, such as the Granite Wash play and the Barnett Shale. Additionally, supply in both of these areas has benefited from enhanced horizontal drilling and fracturing techniques, enabling higher flow rates from the wells of the producers. As drilling rates improve, and the number of drilling rigs increase, we would expect the demand for our services to increase. 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. Favorable pricing for NGLs relative to natural gas has encouraged producers to increase production in the Granite Wash play due to the high NGL and condensate content. Our Anadarko basin wells generally have long lives with predictable flow rates. Producers are pursuing wells with higher condensate and oil production relative to historical activity that was focused on lower-valued gas 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, current market prices for NGLs and crude oil and the application of horizontal drilling and fracturing technology to the formation. 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 million. The Ajax processing plant increases the total processing capacity of our Anadarko system by approximately 150 million cubic feet per day, or MMcf/d, to approximately 1,150 MMcf/d and also increases the system s condensate stabilization capacity by approximately 2,000 Bpd. The Ajax processing plant is capable of producing approximately 15,000 barrels per day, or Bpd, of NGLs now that the Texas Express NGL pipeline, which we refer to as the mainline, was completed and put into operation during the fourth quarter of 2013.

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 marketing business. A portion of our owned NGLs is sold directly to OneOk Partners, L.P. (ONEOK), while the remainder is sold to our 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; and 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. The East Texas basin also includes multiple other natural gas and oil formations that are frequently explored, including the Woodbine, Travis Peak, James Lime, Rodessa, and Pettite, among other formations. Our 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 formations using horizontal drilling and multistage fracturing.

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 is expected to serve existing and prospective customers pursuing production in the Cotton Valley formation. 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 million and expect it to commence service in early 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 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 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 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. Our 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.

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 U.S. 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 marketing business.

Texas Express NGL System

Volumes from the Rockies, Permian basin and Mid-Continent regions will be 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 will be able to access the system upon the completion of the Front Range Pipeline by Enterprise Products Partners, DCP Midstream and Anadarko Petroleum Corporation, which could occur as early as the first quarter of 2014.

The Texas Express NGL system commenced startup operations during the fourth quarter of 2013. During startup operations, revenue recognition is delayed while the system is being filled with NGLs but operating costs are recognized. Additionally, the Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. These factors in combination contributed to lower equity earnings.

Competition. Competition for our natural gas 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.

Trucking and NGL Marketing Operations

We also include our trucking and NGL marketing operations in our Natural Gas segment. The primary role of our trucking and NGL marketing business is to 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 trucking and NGL 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 trucking and NGL marketing business primarily consist of:

- Approximately 250 transport trucks, 300 trailers and 205 railcars for transporting NGLs;

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- 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 trucking and NGL marketing services we provide to our gathering, processing and transportation business and to third-party customers. These agreements provide our trucking and NGL marketing business with the following:

- up to approximately 79,000 Bpd of firm NGL fractionation capacity;
- approximately 2.5 Bcf of firm natural gas storage capacity;
- up to approximately 120,000 Bpd 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 four NGL pipeline transportation companies; and
- approximately 5.0 MMBbls of firm NGL storage capacity.

NGL Marketers. Most of the customers of our trucking and NGL marketing operations are wholesale customers, such as refiners and petrochemical producers, fractionators, propane distributors and industrial, utility and power plant customers.

Supply and Demand. Supply for our trucking and NGL marketing business 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. 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 trucking and NGL marketing business assets are geographically located within Texas, Louisiana, Oklahoma and Mississippi, the majority of activities conducted by our trucking and NGL marketing business are conducted within those states. However, our trucking and NGL 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 mitigate 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 trucking and NGL 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 trucking and NGL 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

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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 trucking and NGL marketing operations have 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.

Marketing Segment

Our Marketing segment s objectives are to enhance the value of our gathering and processing assets and generate incremental gross margin. These objectives are achieved primarily from the optimization of natural gas purchased on our gathering and processing assets and transported into various downstream pipelines to credit-worthy customers. Additionally, our Marketing segment transacts with various counterparties to obtain transportation and storage assets that are used to enhance existing natural gas purchases and sales

Since our gathering and intrastate wholesale customer pipeline assets are geographically located within Texas and Oklahoma, the majority of activities conducted by our Marketing segment are focused within these areas, or points downstream of these locations.

Customers. Natural gas purchased by our Marketing business is sold to industrial, utility and power plant end use customers. In addition, gas is sold to marketing companies at various market hubs. These sales are typically priced based upon a published daily or monthly price index. Sales to end-use customers incorporate a pass-through charge for costs of transportation and additional margin to compensate us for associated services.

Supply and Demand. Supply for our Marketing business depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our Natural Gas business. Demand is typically driven by weather-related factors with respect to power plant and utility customers and industrial demand.

Our Marketing business uses third-party storage capacity to balance supply and demand factors within its portfolio. Our Marketing business pays third-party storage facilities and pipelines for the right to store gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts and to take advantage of price differential opportunities. Our Marketing business leases third-party pipeline capacity downstream from our Natural Gas assets under firm transportation contracts, which capacity is dependent on the volumes of natural gas from our natural gas assets. This capacity is leased for various lengths of time and at rates that allow our Marketing business to diversify its customer base by expanding its service territory. Additionally, this transportation capacity provides assurance that our natural gas will not be shut in, which can result from capacity constraints on downstream pipelines.

Competition. Our Marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and natural gas producers, independent aggregators and regional marketing companies.

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REGULATION

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

The FERC regulates the interstate pipeline transportation of crude oil, petroleum products, and other liquids such as NGL s, collectively called petroleum pipelines or liquids pipelines. Our Lakehead, North Dakota and Ozark systems are our primary interstate common carrier liquids pipelines subject to regulation by the FERC under the Interstate Commerce Act, or ICA, the Energy Policy Act of 1992, or EP Act, and rules and orders promulgated thereunder. As common carriers in interstate commerce, these pipelines provide service to any shipper who makes a reasonable request for transportation services, provided that the shipper satisfies the conditions and specifications contained in the applicable tariff. The ICA requires us to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier pipelines, as well as the rules and regulations governing these services.

The ICA gives the FERC the authority to regulate the rates we can charge for service on interstate common carrier pipelines. The ICA requires, among other things, that such rates be just and reasonable and that they not be unduly discriminatory or unduly preferential to certain shippers. The ICA permits interested parties to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate the rates to determine if they are just and reasonable. If the FERC finds the new or changed rate unlawful, it is authorized to require the carrier to refund, with interest, the amount of any revenues in excess of the amount that would have been collected during the term of the investigation at the rate properly determined to be lawful. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

In October 1992, Congress passed the EP Act, which deemed petroleum pipeline rates that were in effect for the 365-day period ending on the date of enactment, or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period, to be just and reasonable under the ICA (i.e., grandfathered). The EP Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party must show: (1) that it was contractually barred from challenging the rates during the relevant 365-day period; (2) that there has been a substantial change after the date of enactment of the EP Act in the economic circumstances of the pipeline or in the nature of the services that were the basis for the rate, or (3) that the rate is unduly discriminatory or unduly preferential.

The FERC determined our Lakehead system rates are not covered by the grandfathering provisions of the EP Act because they were subject to challenge prior to the effective date of the statute. We believe that the rates for our North Dakota and Ozark systems in effect at the time of the EP Act should be found to be subject to the grandfathering provisions of the EP Act because those rates were not suspended or subject to protest or complaint during the 365-day period established by the EP Act.

The EP Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561 which adopted an indexing rate methodology for petroleum pipelines. Under these regulations, which became effective January 1, 1995, petroleum pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels may be protested, but such protests generally must show that the rate increase resulting from application of the index is substantially in excess of the pipeline s increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline s filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling, although a pipeline is not required to reduce its rate below the level grandfathered under the EP Act. Under Order No. 561, a pipeline must as a general rule utilize the indexing methodology to change its rates. The FERC, however, uses cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach in certain specified circumstances.

The tariff rates for our Ozark system are primarily set under the FERC indexing rules. The tariff rates for our Lakehead and North Dakota systems are set using a combination of the FERC indexing rules (which apply to the base rates on those systems) and FERC-approved surcharges for particular projects that were approved under the FERC s settlement rules.

Under Order No. 561, the original inflation index adopted by the FERC (for the period January 1995 through June 2001) was equal to the annual change in the Producer Price Index for Finished Goods, or PPI-FG, minus one percentage point. The index is subject to review every five years. For the period from July 2001 through June 2006, the FERC set the index at the PPI-FG without an upward or downward adjustment. For the period from July 2006 through June 2011, the FERC set the index at the PPI-FG plus 1.3 percentage points. The index as of July 1, 2010 was negative, resulting in a general downward adjustment of petroleum pipeline rates as of that date.

On December 16, 2010, the FERC set the index for the period from July 2011 through June 2016 at PPI-FG plus 2.65 percentage points. The FERC s December 16, 2010 order was challenged and an appeal was filed by a shipper with the D.C Circuit Court. However, on December 6, 2011, the shipper filed a motion requesting that the appeal be dismissed. Therefore no further judicial or commission review of the decision occurred.

The index as of July 1, 2012 resulted in an increase of approximately 8.6% to the Lakehead, Ozark and North Dakota portion of their indexed rates. A shipper filed a protest, challenging the proposed increase to the Lakehead rates arguing that Lakehead was not entitled to the increase. The Commission dismissed the protest and the Lakehead rates, as filed, are in effect.

The index as of July 1, 2013 resulted in an increase of approximately 4.6% to the Lakehead, Ozark and North Dakota portion of their indexed rates. No protests were filed and the rates are in effect.

FERC Allowance for Income Taxes in Interstate Common Carrier Pipeline Rates

In May 2005, the FERC adopted a policy statement providing that pipelines regulated by FERC that are owned by entities organized as master limited partnerships, or MLPs, could include an income tax allowance in their cost-of-service rates to the extent the income generated from regulated activities was subject to an actual or potential income tax liability. Pursuant to this policy statement, a FERC-regulated pipeline that is a tax pass-through entity seeking such an income tax allowance must establish that its owners, partners or members have an actual or potential income tax obligation on the company s income from regulated activities. This tax allowance policy was upheld on appeal by the U. S. Court of Appeals for the D.C. Circuit, also referred to as the D.C. Circuit Court, in May 2007. Whether a particular pipeline s owners have an actual or potential income tax liability is reviewed by the FERC on a case-by-case basis. To the extent any of our FERC-regulated oil pipeline systems were to file cost-of-service rates, their entitlement to an income tax allowance would be assessed under the FERC policy statement and the facts existing at the relevant time.

FERC Return on Equity Policy for Oil Pipelines

On April 17, 2008, the FERC issued a Policy Statement regarding the inclusion of MLPs in the proxy groups used to determine the return on equity, or ROE, for oil pipelines. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity,* 123 FERC ¶ 61,048 (2008), *rehearing denied,* 123 FERC ¶ 61,259 (2008). No petitions for review of the Policy Statement were filed with the D.C. Circuit Court. The Policy Statement largely upheld the prior method by which ROEs were calculated for oil pipelines, explaining that MLPs should continue to be included in the ROE proxy group for oil pipelines, and that there should be no ceiling on the level of distributions included in the FERC s current discounted cash flow, or DCF, methodology. The Policy Statement further indicated that the Institutional Brokers Estimate System, or IBES, forecasts should remain the basis for the short-term growth forecast used in the DCF calculation and there should be no modification to the current respective two-thirds and one-third weightings of the short and long-term growth factors. The primary change to the prior ROE methodology was the Policy Statement s holding that the gross domestic product, or GDP, forecast used for the long-term growth rate should be reduced by 50% for all MLPs included in the proxy group. Everything else being equal, that change will result in somewhat lower ROEs for oil pipelines than would have been calculated under the prior ROE methodology. The actual ROEs to be calculated under the new Policy Statement, however, are dependent on the companies included in the proxy group and the specific conditions existing at the time the ROE is calculated in each case.

Accounting for Pipeline Assessment Costs

In June 2005, the FERC issued an order in Docket AI05-1 describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the United States Department of Transportation, or DOT, and the Pipeline and Hazardous Materials Safety Administration, or PHMSA. The order took effect on January 1, 2006. Under the order, FERC-regulated companies are generally required to recognize costs incurred for performing pipeline assessments that are part of a pipeline integrity management program as a maintenance expense in the period in which the costs are incurred. Costs for items such as rehabilitation projects designed to extend the useful life of the system can continue to be capitalized to the extent permitted under the existing rules. The FERC denied rehearing of its accounting guidance order on September 19, 2005.

Prior to 2006, we capitalized first time in-line inspection programs, based on previous rulings by the FERC. In January 2006, we began expensing all first-time internal inspection costs for all our pipeline systems, whether or not they are subject to the FERC s regulation, on a prospective basis. We continue to expense secondary internal inspection tests consistent with the previous practice. Refer to Note 2. *Summary of Significant Accounting Policies* included in our consolidated financial statements of this annual report on Form 10-K for additional discussion.

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 Texas Railroad Commission 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 Texas Railroad Commission via its Informal Complaint Process.

In Oklahoma, intrastate natural gas pipelines and gathering systems are subject to regulation by the Oklahoma Corporation Commission (OCC). Specifically, the OCC is vested with the authority to prescribe and enforce rates for the transportation and transmission and sale 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 day s 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 that fails to comply with OCC rate requirements is subject to 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 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. At least one of our intrastate pipelines will file for FERC approval of new rates 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, 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.

Sales of Natural Gas, Crude Oil, Condensate and Natural Gas Liquids

The price at which we sell natural gas currently is not subject to federal or state regulation except for certain systems in Texas. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC s jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and to facilitate price transparency in markets for the wholesale sale of physical natural gas.

Our sales of crude oil, condensate and NGLs currently are not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC s jurisdiction under the ICA. Regulations implemented by the FERC could increase the cost of transportation service on certain petroleum products pipelines, however, we do not believe that these regulations will affect us any differently than other marketers of these products transporting on ICA regulated pipelines.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment for the passage of oil and natural gas through the pipelines of one country across the territory of the

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other. Individual international border crossing points require United States government permits that may be terminated or amended at the discretion of the United States Government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

Tariffs and Transportation Rate Cases

Lakehead system

Under the published rate tariff as of December 31, 2013 for transportation on the Lakehead system, the rates for transportation of light, medium and heavy crude oil from the International border near Neche, North Dakota and from Clearbrook, Minnesota to principal delivery points are set forth below:

	Published Transportation Rate Per Barrel [1]		
	Light	Medium	Heavy
From International Border near Neche, North Dakota:			
To Clearbrook, Minnesota	$ 0.3982	$ 0.4213	$ 0.4622
To Superior, Wisconsin	$ 0.8293	$ 0.8851	$ 0.9827
To Chicago, Illinois area	$ 1.8070	$ 1.9428	$ 2.1811
To Marysville, Michigan area	$ 2.1750	$ 2.3403	$ 2.6302
To Buffalo, New York area	$ 2.2285	$ 2.3982	$ 2.6951
Clearbrook, Minnesota to Chicago	$ 1.6080	$ 1.7206	$ 1.9181

(1) Pursuant to FERC Tariff No. 43.12.0 as filed with the FERC and with an effective date of July 1, 2013 (converted from $/m3 to $/Bbl).

The transportation rates as of December 31, 2013 for medium and heavy crude oil are higher than the transportation rates for light crude oil set forth in this table to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. The Lakehead system periodically adjusts transportation rates as allowed under the FERC s index methodology and the tariff agreements described below.

Base Rates

The base portion of the transportation rates for our Lakehead system are subject to an annual adjustment, which cannot exceed established ceiling rates as approved by the FERC and are determined in compliance with the FERC approved index methodology.

1998 Settlement Agreement

On December 21, 1998, the FERC issued an order in Docket No. OR99-2-000 approving an uncontested Settlement Agreement, referred to as the 1998 Settlement Agreement, between Lakehead and CAPP with respect to three agreed-upon changes to our Lakehead system s rates: (1) a surcharge to recover costs of an expansion project known as the System Expansion Program Phase II, or SEP II; (2) a surcharge to recover costs of the Terrace expansion program; and (3) an increase in the surcharge for heavy petroleum to reflect a change in Lakehead s operating capability to transport heavier grades of petroleum.

SEP II Surcharge

Under the Settlement Agreement with CAPP that the FERC approved in 1996 and reconfirmed in 1998, Lakehead implemented a transportation rate surcharge related to SEP II. This cost-of-service surcharge is added to the base transportation rates and is trued-up annually April 1st for actual costs and throughput from the previous calendar year and is not subject to indexing. The term of the SEP II portion of the Settlement

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Agreement was 15 years, beginning in 1999 and expiring December 31, 2013. Lakehead is currently in discussions regarding a new agreement.

Terrace Surcharge

Under the 1998 Settlement Agreement, the Lakehead system implemented a transportation rate surcharge for the Terrace expansion program, referred to as the Terrace Surcharge, of approximately $0.013 per barrel for light crude oil from the Canadian border to Chicago. The surcharge remained at this level through December 31, 2013, when the Terrace Surcharge expired.

Facilities Surcharge

In June 2004, the FERC approved an Offer of Settlement in Docket No. OR04-2-000 between Lakehead and CAPP, which implemented a Facilities Surcharge to be calculated separately from and incrementally to the then-existing surcharges in its tariff rates, *Enbridge Energy, Limited Partnership*, 107 FERC ¶ 61,336 (2004). The Facilities Surcharge is intended to be utilized to include additional projects negotiated and agreed upon between Lakehead and CAPP as a transparent, cost-of-service based tariff mechanism. This allows the Lakehead system to recover the costs associated with particular shipper-requested projects through an incremental surcharge layered on top of the existing base rates and other FERC approved surcharges already in effect. The Facilities Surcharge Mechanism, or FSM, Settlement requires the Lakehead system to adjust the Facilities Surcharge annually to reflect the latest estimates for the upcoming year and to true-up the difference between estimates and actual cost and throughput data in the prior year.

The FERC permitted the Facilities Surcharge to take effect as of July 1, 2004, and the FSM was expressly designed to be open-ended. In its approval of the FSM Settlement, the Commission accepted the Lakehead system s proposal to submit for Commission review and approval future agreements resulting from negotiations with CAPP where the parties have agreed that recovery of costs through the Facilities Surcharge is desirable and appropriate. At the time the FSM was initially established, four projects were included in the Facilities Surcharge:

(1) The Griffith Hartsdale Transfer Lines Project;

(2) The Hartsdale Tanks Project;

(3) The Superior Manifold Modification Project; and

(4) The Line 17 (Toledo) Expansion Project.

On August 14, 2008, the FERC approved an Amendment to the FSM Settlement to allow the Lakehead system to include in the Facilities Surcharge particular shipper-requested projects that are not yet in service as of April 1^{st} of each year, provided there is an annual true-up of throughput and cost estimates. *Enbridge Energy, Limited Partnership*, 124 FERC ¶ 61,159 (2008). The FERC also approved the addition of four new projects to the Facilities Surcharge (Docket No. OR08-10-000):

(5) Southern Access Mainline Expansion;

(6) Tank 34 at Superior Terminal and Tank 79 at Griffith Terminal;

(7) Clearbrook Manifold; and

(8) Tank 35 at Superior Terminal and Tank 80 at Griffith Terminal.

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On August 28, 2009, the FERC accepted the Supplement to the Settlement (Docket No. OR09-5-000) to allow the following three new projects:

(9) Southern Lights Replacement Capacity Project;

(10) Eastern Access (Trailbreaker) Backstopping Agreement; and

(11) Line 5 Expansion Backstopping Agreement.

On March 30, 2010, the FERC accepted the Supplement to the Settlement (Docket No. OR10-7-000) to permit the recovery of the costs associated with two new projects:

(12) Alberta Clipper Pipeline; and

(13) Line 3 Conversion Project.

On March 31, 2011, the FERC accepted the Supplement to the Settlement (Docket No. OR11-5-000) to permit the recovery of the costs associated with one new project:

(14) Line 6B Integrity Program.

On March 29, 2012, the FERC accepted the Supplement to the Settlement (Docket No. OR12-8-000) to permit the recovery of the costs associated with two new projects:

(15) Line 6B Pipeline Replacement and Dig Program Project; and

(16) Griffith Terminal Expansion Project.

On February 13, 2013, the FERC accepted the Supplement to the Settlement (Docket No. OR13-11-000) to permit the recovery of the costs associated with two more projects:

(17) Flanagan Tank Replacement Project; and

(18) Eastern Access Phase 1 Mainline Expansion Project.

On December 13, 2013, Enbridge filed a Supplement to the Settlement seeking approval for recovery of the costs associated with two more projects:

(19) Eastern Access Phase 2 Mainline Expansion Project; and

(20) 2014 Mainline Expansions Project.

The Eastern Access Phase 2 Mainline Expansion, or Project 19 above, has an overall capital cost of $531 million and includes a 30 inch pipeline replacement of Line 6B from Ortonville, Michigan to the US/Canada border and one new tank at Griffith, Indiana. The project is expected to add 260,000 bpd of capacity on that segment.

The 2014 Mainline Expansions, or Project 20 above, has an overall estimated capital cost of $420 million with two main components:

a) The Line 67 Alberta Clipper Expansion involves pump station upgrades and two new tanks at Superior, Wisconsin which will provide an additional 120,000 bpd of capacity on Line 67 from the US/Canada border to Superior, Wisconsin at an estimated capital cost of $205 million;

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b) The Line 61 Southern Access Expansion involves adding one new pump station, additional pump station upgrades, and the addition of three new tanks at Flanagan, Illinois, which will provide an additional 160,000 bpd of capacity from Superior, Wisconsin to Flanagan, Illinois at an estimated capital cost of $215 million.

For Line 67 of the 2014 Mainline Expansions, it is now anticipated that it will take longer to obtain regulatory approval than planned. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput.

As of December 31, 2013, the Facilities Surcharge was $0.6515 per barrel for light crude oil movements from the International border near Neche, North Dakota to Chicago, Illinois.

Other Tariff and Transportation Rate Cases

Lakehead was subject to two complaint proceedings and one protest in 2013, all three of which were initiated in 2012. On May 11, 2012, PBF Holding Company LLC and Toledo Refining Company LLC (PBF) filed a complaint with the FERC alleging that Enbridge Energy, Limited Partnership (Enbridge) was discriminating against light crude shippers in favor of heavy crude shippers by failing to move light sour crude from Line 5 to Line 6 to equalize apportionment on the two lines. In its complaint, PBF sought damages under section 16(1) of the *Interstate Commerce Act* for the allegedly unlawful apportionment procedures and practices of Enbridge. On June 11, 2012, Enbridge filed a Motion to Dismiss and Answer to the PBF complaint, stating that it has operated its pipelines in this manner for the past 30 years and that Enbridge believes its current method is the fairest manner to allocate capacity, maximize utilization and take into account the differences between grades of crude. On August 9, 2012, FERC set the matter for hearing, first ordering a settlement process. The settlement proceedings concluded on November 7, 2012, at which time Enbridge and PBF expressed that they were unable to settle the matter. The settlement judge issued an order terminating the settlement process and appointing an Administrative Law Judge for the hearing process, which commenced December 3, 2012. On April 26, 2013, before completion of the hearing process, PBF withdrew its complaint.

High Prairie Pipelines LLC, a subsidiary of Saddle Butte Pipeline, LLC (High Prairie), filed a complaint with the FERC on May 17, 2012, claiming that Enbridge unduly discriminated against High Prairie by failing to provide High Prairie a connection at the Enbridge Clearbrook Terminal. Enbridge formally denied the accusation in a motion to dismiss on June 6, 2012, submitting that FERC does not have the authority to force a pipeline connection. On March 22, 2013, the FERC issued an order dismissing the complaint. On April 22, 2013, High Prairie filed a Request for Rehearing, which the FERC accepted on May 20, 2013. In its order granting rehearing, the FERC stated that rehearing requests would be addressed in a future order.

On October 22, 2012, Enbridge filed a Rules and Regulations tariff, FERC Tariff No. 41.3.0 which revised Enbridge s downstream nomination verification procedure by eliminating a frozen 24-month historical period and substituting it with the capability of each delivery facility to receive volumes from Enbridge. A number of shippers filed protests against the proposed tariff and several other shippers filed motions to intervene in the proceeding. On November 13, 2012, Enbridge filed a response to the motions to intervene and protest, stating it would not be opposed to FERC suspending the tariff for up to seven months and holding a technical conference at which to address the shipper concerns. On December 20, 2012, FERC issued an order accepting and suspending Tariff 41.3.0 and established a Technical Conference, which was held at the FERC on February 6, 2013. As a result of consultations with shippers, Enbridge filed a revised Destination Verification procedure on March 8, 2013, in its Post-Technical Conference Reply Comments. On July 18, 2013, the FERC issued an order accepting Enbridge s revised Destination Verification procedure effect July 21, 2013.

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International Joint Tariff

FERC Tariff No. 45.2.0, issued May 31, 2013, revised the International Joint Tariff, or IJT, effective July 1, 2013, by increasing the transportation tolls by 0.97% and included a surcharge, adjusted for distance and crude type, of $0.2318 per cubic meter for movements of light crude from the US/Canada border to Chicago, Illinois for the recovery of costs associated with a regulatory change pursuant to Section 20.1 (i) of the Competitive Toll Settlement. The IJT provides rates applicable to the transportation of petroleum from all receipt points in western Canada on the Enbridge Pipelines Canadian Mainline system to all delivery points on the Lakehead Pipeline system owned by Enbridge Energy and to delivery points on the Canadian Mainline located downstream of the Lakehead system. In summary, the IJT provides a simplified tolling structure to cover transportation services that cross the international border and provides a rate that is equal to or less than the sum of the combined Canadian Mainline and Lakehead system rates on file and in effect.

Mid-Continent system

Our Ozark system is located in the Mid-Continent region of the United States. Specifically, the system originates in Cushing and offers transportation service to Wood River. The transportation rate for light crude oil from Cushing to principal delivery points are set forth below.

Effective August 1, 2013, FERC Tariff 51.4.0 provided a volume discount to the transfer charge for all shippers who transferred more than 10,000 barrels per month. Shippers transferring 10,000 barrels or less continued to pay 13.65 cents per barrel, while those shipper who qualified for the discount paid 4.00 cents per barrel.

On September 30, 2013, Enbridge filed FERC Tariff 51.5.0 which cancelled, effective November 1, 2013 the transfer charge at Cushing as the service is now provided by Enbridge Storage (Cushing) L.L.C. on a commercial basis.

The transportation rate for light crude oil from Cushing to principal delivery points are set forth below:

	Published Transportation Rate Per Barrel[(1)]
To Wood River	$ 0.6221

(1) Pursuant to FERC Tariff No. 48.3.0 as filed with the FERC on May 31, 2013, with an effective date of July 1, 2013.

The transportation rates as of December 31, 2013, outlined above, apply to light crude only. Medium and heavy crude oil transportation rates on these systems are higher to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons.

Where applicable, transportation rates are periodically adjusted as allowed under the FERC s index methodology. This methodology allows for an adjustment of transportation rates effective July 1 of each year.

North Dakota system

The North Dakota system consists of both gathering and trunkline assets. Effective January 1, 2008, two new surcharges were implemented as a part of the North Dakota Phase 5 expansion program, referred to as North Dakota Phase 5. In August 2006, the North Dakota system submitted the Phase 5 Offer of Settlement to the FERC for an expansion of the system, which was approved by the Commission on October 31, 2006 (Docket No. OR06-9-000). The Phase 5 Offer of Settlement outlined the mainline expansion and looping surcharges as cost-of-service based surcharges that are trued-up each year to actual costs and volumes and are not subject to the

FERC index methodology. These surcharges were initially applicable for five years immediately following the in-service date of North Dakota Phase 5, which was January 2008. The mainline expansion surcharge is applied to all routes with a destination of Clearbrook and the looping surcharge is applied to volumes originating at either Trenton or Alexander, North Dakota. Effective April 1, 2010, we extended the term of the looping surcharge on our North Dakota system by four years, ending on December 31, 2016 rather than the original date of December 31, 2012. The impact of the term extension reduced the looping surcharge substantially thereby moderating the rate impact on shippers.

On January 18, 2008, Enbridge North Dakota submitted an Offer of Settlement to the FERC to facilitate the Phase 6 expansion of the North Dakota system. Under the terms of the settlement, which were approved by the FERC on October 20, 2008 (Docket No. OR08-6-000), expansion costs are recovered through a cost-of-service based surcharge on all shipments to Clearbrook, Minnesota. The surcharge is in effect for seven years and is trued-up on an annual basis to actual costs and volumes. It is not subject to the FERC index methodology. The Phase 6 surcharge became effective on January 1, 2010 and is in addition to existing base rates and the Phase 5 surcharges.

On August 26, 2010, the North Dakota system and Enbridge Pipelines (Bakken) L.P. filed a Petition for Declaratory Order seeking the approval of priority service for the North Dakota portion of the Bakken Project as well as the overall tariff and rate structure for the United States portions of the program. The Petition for Declaratory Order was approved by the FERC on November 22, 2010 (FERC Docket No. OR10-19-000).

On August 15, 2012, the North Dakota system amended its Rules and Regulations tariff to modify its prorationing policy. Two years prior, on August 30, 2010, the North Dakota system amended its Rules and Regulations tariff by implementing a temporary 24-month freeze on the creation of additional Regular Shippers. The change was intended to eliminate further proliferation of New Shippers and mitigate the erosion of Regular Shipper capacity on the system. During the 24-month period commencing on October 1, 2010, shippers that had not yet attained Regular Shipper status as of that date were no longer permitted to become Regular Shippers until the later of: (i) the date on which that shipper has transported crude oil during nine of the previous 12 months or (ii) a month in which the system as a whole is not in apportionment. The North Dakota system s Rules and Regulations tariff was approved by the FERC Order 132 FERC ¶ 61,274, issued on September 30, 2010 (Docket No. IS10-614-000). With the temporary 24-month freeze set to expire, a new tariff filed on August 15, 2012 intended to provide relief for all New Shippers who had been frozen in the New Shipper class during the freeze, but had developed sufficient history to qualify as a Regular Shipper. North Dakota intended to do this by allowing all qualifying shippers to achieve Regular Shipper status and then reserving less than 10% of capacity for New Shippers under the condition that any future expansions of capacity to Clearbrook, Minnesota would solely benefit New Shippers until such time as their access to capacity totaled at least 10% of the total available capacity to Clearbrook. Notwithstanding a protest that was filed, the Commission accepted the tariff effective September 15, 2012.

On November 2, 2012, the North Dakota system submitted a Petition for Declaratory Order seeking approval of a related Offer of Settlement with respect to a major expansion and extension of the North Dakota system known as the Sandpiper Project. The project would have resulted in a substantial increase in the capacity available to transport Bakken crude both to and through Clearbrook, North Dakota to Superior, Wisconsin. The terms of the proposal include, among other things, the addition of a cost of service rate surcharge to the existing rates to Clearbrook, and a new cost of service tariff rate from Clearbrook to Superior. Six protests of the project were filed with the FERC, to which Enbridge responded on November 12, 2012, reaffirming the benefits of the Sandpiper Project and the support it has received from a cross section of shippers, including 15 who signed the Offer of Settlement. On March 22, 2013, the Petition was denied by the FERC on the basis that an Offer of Settlement requires the unanimous approval of all shippers, and the protests indicated that that hurdle was not met in this case. A revised proposal for the Sandpiper Project, including the availability of contracted space on the pipeline, is currently being offered to shippers through an open season and it is anticipated that a new Petition for Declaratory Order will be filed in 2014.

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On March 1, 2013, the Bakken Project went into service and has the capability to transport 145,000 Bpd of Bakken crude from the North Dakota system to Cromer, Manitoba, Canada. Tariffs to allow movements on the Bakken Project and for delivery to the new Enbridge Rail (North Dakota) LLC facility at Berthold, North Dakota were filed on December 18, 2012 to be effective January 15, 2013.

On March 1, 2013, FERC Tariff 72.22.0 was filed, trueing-up the Phase 5 looping and Phase 6 surcharges and cancelling the Phase 5 mainline surcharge, which expired on December 31, 2012. The filing was protested by one shipper who wanted the surcharge to be applicable to barrels that delivered to Berthold, North Dakota in addition to Clearbrook, Minnesota. The FERC rejected the protest on the basis that Enbridge correctly implemented the terms of the approved Offer of Settlement covering the surcharge. A complaint was filed by the same shipper on July 25, 2013 (Docket No. OR13-28-000) asking the FERC to throw out the Offer of Settlement on the basis that it no longer reflected the circumstances on the North Dakota system. The FERC rejected the complaint in Order 145 FERC ¶ 61,050 on the basis that the complainant did not provide sufficient evidence to convince the FERC to overturn an approved Settlement. On December 13, 2013, the shipper filed a Petition for Review with the U.S. District Court of Appeals.

On May 1, 2013, FERC Tariff 72.23.0 was filed, which among other things established Little Muddy, North Dakota as a new receipt point on the system and lifted a previously implemented discount to the rates from Alexander and Trenton, North Dakota to Tioga, North Dakota. The tariff went into effect June 1, 2013.

On May 8, 2013, FERC Tariff 71.15.0 was filed, to be effective on May 9, 2013. The tariff introduced a new quality specification for the presence of hydrogen sulfide (no more than 5 parts per million) in the crude in order to protect the health and safety of North Dakota system employees. The tariff was protested by shippers who disliked the short notice provided and thought the specification was too strict; however the FERC rejected the protest and upheld the tariff due to the significant safety concerns surrounding hydrogen sulfide.

On July 5, 2013, FERC Tariff 72.25.0 was filed, to be effective on August 1, 2013. The tariff established a new delivery point at Berthold, North Dakota, connecting the North Dakota system to a merchant tankage facility provided by Enbridge Storage (North Dakota) LLC.

On July 31, 2013, FERC Tariff 71.16.0 was filed, modifying the non-performance penalty. Following the August 31, 2013 effective date, the volumetric aspect of the penalty only applies if the North Dakota system is in apportionment.

On August 30, 2013, and September 30, 2013, FERC Tariffs 72.26.0 and 72.27.0 respectively, were filed. These tariffs established initial gathering and truck unloading services and charges at Trenton, North Dakota and Stanley, North Dakota. The two $0.1046/Bbl interconnection rates resulted from shippers requests for pipeline interconnections to facilitate receipts into the system at those locations. The tariffs became effective October 1, 2013 and November 1, 2013.

On November 25, 2013, the North Dakota system changed its legal name from Enbridge Pipelines (North Dakota) LLC to North Dakota Pipeline Company LLC. Tariffs were filed on December 23 and December 24, 2013 with the FERC to reflect the new company name.

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The rates and surcharges for transportation of light crude oil on our North Dakota system are set forth below:

	Published Transportation Rate Per Barrel(1)(2)
From Glenburn, Minot, Newburg, Sherwood, Berthold and Stanley, North Dakota to Clearbrook, Minnesota	$ 1.8739
From Grenora, North Dakota to Clearbrook	$ 2.0258
From Flat Lake and Reserve, Montana to Clearbrook, Minnesota	$ 2.0594
From Tioga, North Dakota to Clearbrook, Minnesota	$ 1.9072
From Trenton, North Dakota to Clearbrook, Minnesota	$ 2.3970
From Alexander, North Dakota to Clearbrook, Minnesota	$ 2.4473
From Little Muddy, North Dakota to Clearbrook, Minnesota	$ 2.3970
From Grenora, North Dakota to Tioga, North Dakota	$ 0.7116
From Flat Lake, Montana to Tioga, North Dakota	$ 0.7430
From Reserve, Montana to Tioga, North Dakota	$ 0.7430
From Trenton, North Dakota to Tioga, North Dakota	$ 0.8269
From Alexander, North Dakota to Tioga, North Dakota	$ 0.8771
From Little Muddy, North Dakota to Tioga, North Dakota	$ 0.8269
From (pump-over) Stanley, North Dakota to Stanley, North Dakota	$ 0.2615
From Tioga, North Dakota to Stanley, North Dakota	$ 0.9843
From Grenora, North Dakota to Stanley, North Dakota	$ 1.0935
From Reserve, Montana to Stanley, North Dakota	$ 1.1245
From Trenton, North Dakota to Stanley, North Dakota	$ 1.4512
From Alexander, North Dakota to Stanley, North Dakota	$ 1.4976
From Little Muddy, North Dakota to Stanley, North Dakota	$ 1.4512
From Berthold, North Dakota to Berthold, North Dakota	$ 0.8121
From Stanley, North Dakota to Berthold, North Dakota	$ 0.8736
From Tioga, North Dakota to Berthold, North Dakota	$ 1.0683
Gathering from Newburg, North Dakota or Flat Lake, Montana	$ 0.8611

(1) Pursuant to FERC Tariff No. 72.28.0 as filed with the FERC on December 23, 2013, with an effective date of December 23, 2013.

(2) The looping surcharge was modified in 2009 to extend the cost recovery period by an additional four years, which reduced the rates.

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

Our transmission and gathering pipelines are subject to regulation by the DOT and PHMSA, under Title 49 of the United States Code of Federal Regulations Parts 190-199 (Pipeline Safety Act, or PSA) relating to the design, installation, testing, construction, operation, replacement and management of transmission and gathering pipeline facilities. PHMSA is the agency charged with regulating the safe transportation of hazardous materials under all modes of transportation, including interstate and intrastate pipelines. Periodically the PSA has been reauthorized and amended, imposing new mandates on the regulator to promulgate new regulations and imposing direct mandates on operators of pipelines.

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On December 29, 2006, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, referred to as PIPES of 2006, was enacted, which further amended the PSA. Many of the provisions were welcomed, including strengthening excavation damage prevention and enforcement. The most significant provisions of PIPES of 2006 that affect us include a mandate to PHMSA to remove most exemptions from federal regulations for liquid pipelines operating at low stress and mandates PHMSA to undertake rulemaking requiring pipeline operators to have a human factors management plan for pipeline control room personnel, including consideration for controlling hours of service. On December 3, 2009, the final rule for the Control Room Management/Human Factors was published and in June 2011, the rule s implemental deadlines were expedited in order to realize the safety benefits sooner than established in the original rule. The final rule applying safety regulations to all rural onshore hazardous liquid low-stress pipelines was published May 5, 2011 and became effective October 1, 2011.

In April 2011, as a reaction to recent significant accidents involving natural gas explosions and hazardous liquids releases, the U.S. Department of Transportation Secretary Ray LaHood and PHMSA issued a Call to Action to engage all the state pipeline regulatory agencies, technical and subject matter experts, and pipeline operators to accelerate the repair, rehabilitation, and replacement of the highest-risk pipeline infrastructure. The Call addresses many concerns related to pipeline safety, such as ensuring pipeline operators know the age and condition of their pipelines, proposing new regulations to strengthen reporting and inspection requirements, and making information about pipelines and the safety record of pipeline operators easily accessible to the public.

In order to further strengthen pipeline safety regulations, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law on January 3, 2012. As a result of this Act, PHMSA will be finalizing new rules to implement lessons learned from recent pipeline accidents. Pending legislation includes: requiring automatic or remote-controlled shutoff valves on new or replaced transmission pipeline facilities and requiring operators to use leak detection systems where practicable. In addition, to support PHMSA s investigation and enforcement operations for the increasing number of regulations, the Act authorizes additional PHMSA inspectors, and doubles the maximum civil penalties for pipeline operators who fail to observe safety rules. Also included within this act are: the consideration of expanding integrity management requirements beyond high consequence areas, the assessment of the need for new regulations covering diluted bitumen transportation, the requirement to validate and verify maximum allowable operating pressures, and the determination of the effect of depth of cover over buried pipelines in accidental releases of hazardous liquids at water crossings.

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. Any release that results in an enforcement action, or National Transportation Safety Board, or NTSB, investigation, such as those associated with Line 6B near Marshall, MI and Line 14 near Grand Marsh, WI could have a material impact on system throughput or compliance costs. As part of the Corrective Action Order related to the Grand Marsh release, we were required to develop and implement a comprehensive plan to address wide-ranging safety initiatives for not only Line 14, but for our entire Lakehead System.

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

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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 federal Clean Air Act, or CAA, and the federal 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. In January 2010, the Environmental Protection Agency, or EPA, published that the effective date of the Spill Prevention, Control, and Countermeasures Rule Amendments would be November 10, 2010. However, on October 7, 2010, the EPA issued an extension to the compliance date to November 10, 2011. While the operations of our pipeline facilities are subject to the rule, we prepared the necessary plans for compliance prior to the November 2011 effective date. In 2009, the EPA published the Greenhouse Gas Recordkeeping and Reporting Rule, which requires applicable facilities to record and report greenhouse gas emissions from combustion sources beginning January 1, 2010. As a part of the reporting rule, in November 2010, the EPA published the requirements for reporting emissions from Petroleum and Natural Gas Systems beginning January 1, 2011. While the operations of our pipelines are subject to the rule, we do not believe that the rule requirements will have a material effect on our operations. Annual emissions from combustion activities in 2010 were reported prior to the September 30, 2011 deadline. Facilities subject to existing Greenhouse Gas Reporting rules reported emissions prior to the March 31, 2012 deadline for 2011 emissions. Facilities subject to the new reporting rules in 2011 reported emissions prior to the September 28, 2012 deadline. On August 23, 2011, the EPA proposed New Source Performance Standards (NSPS), Subpart OOOO, for volatile organic compounds, or VOC, and sulfur dioxide, or SO_2, emissions from the Oil and Natural Gas Sector. The final standards were

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published and became effective on August 16, 2012. The compliance dates range from October 15, 2012, to April 15, 2015, dependent on the affected equipment. 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.

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 federal 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 crude oil, 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, Enbridge Management, as the entity with managerial responsibility for us, 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

Neither we nor Enbridge Management have any employees. Our General Partner has delegated to Enbridge Management, pursuant to a delegation of control agreement, substantially all of the responsibility for our day-to-

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day management and operation. Our General Partner, however, retains certain functions and approval rights over our operations. To fulfill its management obligations, Enbridge Management has entered into agreements with Enbridge and several of its affiliates to provide Enbridge Management with the necessary services and support personnel who act on Enbridge Management s behalf as its agents. We are ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

INSURANCE

Our operations are subject to many hazards inherent in the liquid petroleum and natural gas gathering, treating, processing and transportation 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 maintain commercial liability insurance coverage that is consistent with coverage considered customary for our industry. We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries through the policy renewal date of May 1, 2014. The insurance coverage also includes property insurance coverage on our assets, except pipeline assets that are not located at water crossings, including earnings interruption resulting from an insurable event. 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 Enbridge and other Enbridge subsidiaries.

The coverage limits and deductible amounts at December 31, 2013 for our insurance policies:

Insurance Type	Coverage Limits	Deductible Amount
	(in millions)	
Property and business interruption	Up to $ 700.0	$ 10.0
General liability	Up to $ 685.0	$ 0.1
Pollution liability (as included under General Liability)	Up to $ 685.0	$ 10.0

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.enbridgepartners.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.

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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

Our actual 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 maintain or increase cash distributions.

Our strategy 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 currently 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 needed or may adversely affect our future results of operations and cash flows.

Our revenues and cash flows may not increase immediately on 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 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 prevalent during the recessionary period of 2008 and 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.

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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.

A downgrade in our credit rating could require us to provide collateral for our hedging liabilities and negatively impact our interest costs and borrowing capacity under our Credit Facilities.

Standard & Poor s, or S&P, Dominion Bond Rating Service, or DBRS, and Moody s Investors Service, or Moody s, rate our non-credit enhanced, senior unsecured debt. Although we are not aware of current plans by the ratings agencies to lower their respective ratings on such debt, we cannot be assured that such credit ratings will not be downgraded.

Currently, we are parties 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 us to provide assurances of performance if our counterparties exposure to us exceeds certain levels or thresholds. We generally provide letters of credit to satisfy such requirements. At December 31, 2013, we have provided $76.1 million in the form of letters of credit as assurances of performance for our then outstanding derivative financial instruments. In the event that our credit ratings were to decline to the lowest level of investment grade, as determined by S&P and Moody s, we would be required to provide letters of credit in substantially greater amounts to satisfy the requirements of our ISDA® agreements. For example if our credit ratings had been at the lowest level of investment grade at December 31, 2013, we would have been required to provide additional letters of credit in the aggregate amount of $14.8 million. The amounts of any letters of credit we would have to establish under the terms of our ISDA® agreements would reduce the amount that we are able to borrow under our senior unsecured revolving credit facility and our 364-day credit facility, referred to as our Credit Facilities.

We may not have sufficient cash flows to enable us to continue to pay distributions at the current level.

We may not have sufficient available cash from operating surplus each quarter to enable us to pay distributions at the current level. The amount of cash we are able to distribute depends on the amount of cash we generate from our operations, which can fluctuate quarterly based upon a number of factors, including:

- the operating performances of our assets;
- commodity prices;
- actions of government regulatory bodies;
- the level of capital expenditures we make;
- the amount of cash reserves established by Enbridge Management;
- our ability to access capital markets and borrow money;
- our debt service requirements and restrictions in our credit agreements;

the ability of MEP to make distributions to us;

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- fluctuations in our working capital needs; and
- the cost of acquisitions.

In addition, the amount of cash we distribute depends primarily on our cash flow rather than net income or net loss. Therefore, we may make cash distributions during periods when we record net losses or may make no distributions during periods when we record net income.

Our acquisition strategy may be unsuccessful if we incorrectly predict operating results, are unable to identify and complete future acquisitions and integrate acquired assets or businesses.

The acquisition of complementary energy delivery assets is a component of our strategy. Acquisitions present various risks and challenges, including:

- the risk of incorrect assumptions regarding the future results of the acquired operations or expected cost reductions or other synergies expected to be realized as a result of acquiring such operations;
- a decrease in liquidity as a result of utilizing significant amounts of available cash or borrowing capacity to finance an acquisition;
- the loss of critical customers or employees at the acquired business;
- the assumption of unknown liabilities for which we are not fully and adequately indemnified;
- 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 or consummate acquisitions in the future.

Our financial performance could be adversely affected if our pipeline systems are used less.

Our financial performance depends to a large extent on the volumes transported on our liquids or natural gas pipeline systems. Decreases in the volumes transported by our systems can directly and adversely affect our revenues and results of operations. The volume transported on our pipelines can be influenced by factors beyond our control including:

- competition;
- regulatory action;
- weather conditions;

storage levels;

alternative energy sources;

decreased demand;

fluctuations in energy commodity prices;

- economic conditions;
- supply disruptions;
- availability of supply connected to our pipeline systems; and
- availability and adequacy of infrastructure to move, treat and process supply into and out of our systems.

As an example, the volume of shipments on our Lakehead system depends heavily on the supplies of western Canadian crude oil. Insufficient supplies of western Canadian crude oil will adversely affect our business by limiting shipments on our Lakehead system. Decreases in conventional crude oil exploration and production activities in western Canada and other factors, including supply disruption, higher development costs and competition, can slow the rate of growth of our Lakehead system. The volume of crude oil that we transport on our Lakehead system also depends on the demand for crude oil in the Great Lakes and Midwest regions of the United States and the volumes of crude oil and refined products delivered by others into these regions and the province of Ontario. Pipeline capacity for the delivery of crude oil to the Great Lakes and Midwest regions of the United States currently exceeds refining capacity.

In addition, our ability to increase deliveries to expand our Lakehead system in the future depends on increased supplies of western Canadian crude oil. We expect that growth in future supplies of western Canadian crude oil will come from oil sands projects in Alberta. Full utilization of additional capacity as a result of our Alberta Clipper and Southern Access pipelines and future expansions of our Lakehead system, will largely depend on these anticipated increases in crude oil production from oil sands projects. A reduction in demand for crude oil or a decline in crude oil prices may make certain oil sands projects uneconomical since development costs for production of crude oil from oil sands is greater than development costs for production of conventional crude oil. Oil sands producers may cancel or delay plans to expand their facilities, as some oil sands producers have done in recent years, if crude oil prices are at levels that do not support expansion. Additionally, measures adopted by the government of the province of Alberta to increase its share of revenues from oil sands development coupled with a decline in crude oil prices could reduce the volume growth we have anticipated in expanding the capacity of our crude oil pipelines.

The volume of shipments on natural gas and NGL systems depends on the supply of natural gas and NGLs available for shipment from the producing regions that supply these systems. Supply available for shipment can be affected by many factors, including commodity prices, weather and drilling activity among other factors listed above. Volumes shipped on these systems are also affected by the demand for natural gas and NGLs in the markets these systems serve. Existing customers may not extend their contracts for a variety of reasons, including a decline in the availability of natural gas from our 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 the natural gas systems were to render the delivered cost of natural gas on our systems uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Our financial performance may be adversely affected by risks associated with the Alberta Oil Sands.

Our Lakehead system is highly dependent on sustained production from the Alberta Oil Sands. Growth in production from the oil sands over the past decade has remained strong due to high oil prices and improved production methods; however the industry faces a number of risks associated with the scope and scale of its projects. Factors and risks affecting the Oil Sands industry include:

- cost inflation;
- labor availability;

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- environmental impact;
- reputation management;
- changing policy and regulation; and
- commodity price volatility.

Alberta Oil Sands producers face a number of challenges that must be managed effectively to allow for sustained growth in the sector. The unprecedented level of development in the Alberta Oil Sands has driven costs upward as a result of a tight labor market, high equipment costs, and costs for commodities such as steel and other raw materials. Labor has been one of the most important considerations for the industry, as Alberta has the lowest unemployment rate in Canada due to the oil and gas industry and as a result, worker wages have risen steadily with industry development over the past several years.

The environmental impact of oil sands development in northern Alberta has been at the forefront of discussion around future industry growth in the region. Labor and environmental groups have expressed their views and concerns about oil sands development and pipeline infrastructure in the public domain and in front of regulators. The primary concerns are greenhouse gas emissions and environmental monitoring and reclamation. Though industry associations have stated that they are not opposed to changes in policy and regulation, the risk of any sort of regulation that may curtail oil sands development or adversely impact the oil and gas industry remains a risk.

Volatility in commodity prices is a concern for the oil sands industry. The relatively high costs and large up front capital investments required by oil sands mega projects makes capital cost recovery a key consideration for future development. Wide commodity price spreads have impacted producer netbacks and margins over the past year and largely result from insufficient pipeline infrastructure and takeaway capacity from producing regions in Alberta. Combined with high labor and operating costs this has forced some producers to reconsider or defer projects until a more favorable climate for infrastructure development can be guaranteed.

Competition may reduce our revenues.

Our Lakehead system faces current and potentially further competition for transporting western Canadian crude oil from other pipelines, which may reduce our volumes and the associated revenues. For our cost-of-service arrangements, these lower volumes will increase our transportation rates. The increase in transportation rates could result in rates that are higher than competitive conditions will otherwise permit. Our Lakehead system competes with other crude oil and refined product pipelines and other methods of delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Chicago, Detroit, Toledo, Buffalo, and Sarnia and the refinery market and pipeline hub located in the Patoka/Wood River area of southern Illinois. Refineries in the markets served by our Lakehead system compete with refineries in western Canada, the province of Ontario and the Rocky Mountain region of the United States for supplies of western Canadian crude oil.

Our Ozark pipeline system faces competition from a competitor pipeline that carries crude oil from Hardisty to Wood River and Patoka in southern Illinois, which came into service in the third quarter of 2010.

Our North Dakota system faces increased competition from rail transportation driven by limited transportation infrastructure to key markets. These transportation and market access constraints have resulted in large crude oil price differences between the North Dakota supply basin and refining market centers. If increased transportation infrastructure is delayed or not built, our North Dakota system could continue to experience reduced system utilization.

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We also encounter competition in our natural gas gathering, treating, and processing and transmission businesses. A number of new interstate natural gas transmission pipelines being constructed could reduce the revenue we derive from the intrastate transmission of natural gas. 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 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.

Our gas marketing operations involve market and regulatory risks.

As part of our natural gas marketing activities, we purchase natural gas at prices determined by prevailing market conditions. Following our purchase of natural gas, we generally resell natural gas 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 natural gas operations may be affected by the following factors:

- our ability to negotiate on a timely basis natural gas 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 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 on comparable terms; and
- changes in, limitations upon or elimination of the regulatory authorization required for our wholesale sales of natural gas in interstate commerce.

Our results may be adversely affected by commodity price volatility and risks associated with our hedging activities.

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, NGL, and crude oil purchase and resale activities, in addition to our natural gas processing activities.

At December 31, 2013, approximately 57% of our gross margin was attributable to contracts with some degree of commodity price exposure. In addition under our keep-whole/wellhead purchase contracts, we have direct exposure to both natural gas and NGL prices because our costs are dependent on the price of natural gas and our revenues are dependent on the price of NGL s. 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 adversely affect our results of operation and cash flows and ability to make distributions.

Additionally, our hedging activities may not be as effective as we intend in reducing the volatility of our 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.

Changes in, or challenges to, our rates 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. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates, 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.

We believe that the rates we charge for transportation services on our interstate common carrier oil and open access natural gas pipelines are just and reasonable under the ICA and NGA, respectively. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, or a regulator s own initiative, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier oil and open access natural gas pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Increased regulation and regulatory scrutiny may reduce our revenues.

Our interstate pipelines and certain activities of our intrastate natural gas pipelines are subject to FERC regulation of terms and conditions of service. In the case of interstate natural gas pipelines, FERC also establishes requirements respecting the construction and abandonment of pipeline facilities. FERC has pending proposals to increase posting and other compliance requirements applicable to natural gas markets. Such changes could prompt an increase in FERC regulatory oversight of our pipelines and additional legislation that could increase our FERC regulatory compliance costs and decrease the net income generated by our pipeline systems.

Compliance with environmental and operational safety regulations may expose us to significant 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, oftentimes requiring difficult and costly actions. 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 operation of liquid petroleum and natural gas gathering, processing, treating and transportation facilities exposes us to the risk of incurring significant environmental costs and liabilities. Additionally, operational modifications,

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including pipeline restrictions, necessary to comply with regulatory requirements and resulting from our handling of liquid petroleum and natural gas, 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. We may incur joint and several strict liability under these environmental laws and regulations in connection with discharges or releases of liquid petroleum and natural gas 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, oftentimes by third parties not under our control. Private parties, including the owners of properties through which our gathering systems pass and facilities where our liquid petroleum and natural gas 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 non-compliance 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, emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase our costs related to operating and maintaining our facilities, and could delay future permitting. At the federal level, the United States Congress has in the past and may in the future consider legislation to reduce emissions of greenhouse gases. On September 22, 2009, the EPA issued a rule requiring nation-wide reporting of greenhouse gas emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. Subsequently, on November 30, 2010, the EPA issued a supplemental rulemaking that expanded the types of industrial sources that are subject to or potentially subject to EPA s mandatory greenhouse gas emissions reporting requirements to include petroleum and natural gas systems.

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 Clean Air Act of 1970, as amended, or CAA, that, in general, 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. On May 13, 2010, the EPA issued the tailoring rule, which served to increase the greenhouse gas emissions threshold that triggers the permitting requirements for major new (and major modifications to existing) stationary sources. Under a phased-in approach, for most purposes, new permitting provisions are required for new facilities that emit 100,000 tons per year or more of carbon dioxide equivalent, or CO2e, and existing facilities making changes that would increase greenhouse gas emissions by 75,000 CO2e. The EPA has also indicated in rulemakings that it may further reduce the current regulatory thresholds for greenhouse gas emissions, making additional sources subject to permitting. On June 26, 2012, in Coalition for Responsible Regulation v. EPA, the U.S. Circuit Court of Appeals for the District of Columbia circuit upheld the bases for the tailoring rule, and ruled that no petitioners had standing to challenge it. On April 18, 2013, the plaintiffs filed a petition for review of that decision by the U.S. Supreme Court.

In addition, more than one-third of the states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap-and-trade programs. Although many of the state-level initiatives have, to date, focused on large sources of greenhouse gas emissions, such as electric power plants, it is possible that in the future sources in states where we operate, such as our gas-fired compressors, could become subject to greenhouse gas-related state regulations. Depending on the particular program, we could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to

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reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for our services.

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.

United States based oil sands development opponents as well as others concerned with environmental impacts of pipeline routes advocated by our competitors have utilized political pressure to influence the timing and whether such permits are granted which could impact future pipeline development.

Measurement adjustments on our pipeline system can be materially impacted by changes in estimation, commodity prices and other factors.

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum pipelines. The three types of oil measurement adjustments that routinely occur on our systems include:

- physical, which results from evaporation, shrinkage, differences in measurement (including sediment and water measurement) between receipt and delivery locations and other operational conditions;

- degradation resulting from mixing at the interface within our pipeline systems or terminals and storage facilities between higher quality light crude oil and lower quality heavy crude oil in pipelines; and

- revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Quantifying oil measurement adjustments is inherently difficult because physical measurements of volumes are not practical as products continuously move through our pipelines and virtually all of our pipeline systems are located underground. In our case, measuring and quantifying oil measurement losses is especially difficult because of the length of our pipeline systems and the number of different grades of crude oil and types of crude oil products we transport. Accordingly, we utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses.

Natural gas measurement adjustments occur as part of the normal operating conditions associated with our natural gas 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 natural gas systems, primarily around our gathering and processing assets; (2) varying qualities of natural gas

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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 natural gas systems.

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 oil and gas hedging transactions. These statutory requirements must be implemented through regulations, primarily through rules to be adopted by the Commodity Futures Trading Commission, or the CFTC. The Dodd-Frank Act provisions may change fundamentally the way many swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which many swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. A considerable number of market participants will be newly regulated as swap dealers or major swap participants, with new regulatory capital requirements and other regulations that impose business conduct rules and mandate how they hold collateral or margin for swap transactions. All market participants are subject to new reporting and recordkeeping requirements.

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

Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions 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.

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

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 facility 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, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues.

We are exposed to restrictions on the ability of Midcoast Operating to repay indebtedness owed to us and MEP and Midcoast Operating to make distributions to us.

We, as lender, entered into a $250 million Working Capital Loan Agreement (the Working Capital Credit Facility) with Midcoast Operating. We, as financial support provider, also entered into a financial support agreement with Midcoast Operating, pursuant to which we will provide letters of credit and guarantees, not to exceed $700 million in the aggregate at any time outstanding, in support of the financial obligations of Midcoast Operating and its wholly owned subsidiaries 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. Our rights to payments under the Working Capital Credit facility and financial support agreement are subordinated to the rights of the lenders under the revolving credit Facility of MEP and Midcoast Operating during the continuation of a default under their revolving credit facility. If Midcoast Operating experiences financial or other problems and fails to comply with their revolving credit facility, it would limit our ability to receive payment of amounts owed to us under these agreements. In addition, MEP and Midcoast Operating are restricted under their revolving credit facility in certain circumstances involving certain defaults thereunder or any events of defaults thereunder from making distributions to us. Any inability of MEP or Midcoast Operating to make distributions, or of Midcoast Operating to repay its indebtedness to us, could reduce our cash flows and affect our results of operations.

RISKS ARISING FROM OUR PARTNERSHIP STRUCTURE AND RELATIONSHIPS WITH OUR GENERAL PARTNER AND ENBRIDGE MANAGEMENT

The interests of Enbridge may differ from our interests and the interests of our unit holders, and the board of directors of Enbridge Management may consider the interests of all parties to a conflict, not just the interests of our unit holders, in making important business decisions.

Enbridge indirectly owns all of the shares of our General Partner and all of the voting shares of Enbridge Management, and elects all of the directors of both companies. Furthermore, some of the directors and officers of our General Partner and Enbridge Management are also directors and officers of Enbridge. Consequently, conflicts of interest could arise between our unitholders and Enbridge.

Our partnership agreement limits the fiduciary duties of our General Partner to our unitholders. These restrictions allow our General Partner to resolve conflicts of interest by considering the interests of all of the parties to the conflict, including Enbridge Management s interests, our interests and those of our General Partner. In addition, these limitations reduce the rights of our unitholders under our partnership agreement to sue our General Partner or Enbridge Management, its delegate, should its directors or officers act in a way that, were it not for these limitations of liability, would constitute breaches of their fiduciary duties.

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We do not have any employees. In managing our business and affairs, we rely on employees of Enbridge, and its affiliates, who act on behalf of and as agents for us. A decrease in the availability of employees from Enbridge could adversely affect us.

Our partnership agreement and the delegation of control agreement limit the fiduciary duties that Enbridge Management and our General Partner owe to our unitholders and restrict the remedies available to our unitholders for actions taken by Enbridge Management and our General Partner that might otherwise constitute a breach of a fiduciary duty.

Our partnership agreement contains provisions that modify the fiduciary duties that our General Partner would otherwise owe to our unitholders under state fiduciary duty law. Through the delegation of control agreement, these modified fiduciary duties also apply to Enbridge Management as the delegate of our General Partner. For example, our partnership agreement:

- permits our General Partner to make a number of decisions, including the determination of which factors it will consider in resolving conflicts of interest, in its sole discretion. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;

- provides that any standard of care and duty imposed on our General Partner will be modified, waived or limited as required to permit our General Partner to act under our partnership agreement and to make any decision pursuant to the authority prescribed in our partnership agreement, so long as such action is reasonably believed by the General Partner to be in our best interests; and

- provides that our General Partner and its directors and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions if they acted in good faith.

These and similar provisions in our partnership agreement may restrict the remedies available to our unitholders for actions taken by Enbridge Management or our General Partner that might otherwise constitute a breach of a fiduciary duty.

Potential conflicts of interest may arise among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Because the fiduciary duties of the directors of our General Partner and Enbridge Management have been modified, the directors may be permitted to make decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders.

Conflicts of interest may arise from time to time among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Conflicts of interest may also arise from time to time between us and our unitholders, on the one hand, and Enbridge Management and its shareholders, on the other hand. In managing and controlling us as the delegate of our General Partner, Enbridge Management may consider the interests of all parties to a conflict and may resolve those conflicts by making decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders. The following decisions, among others, could involve conflicts of interest:

- whether we or Enbridge will pursue certain acquisitions or other business opportunities;

- whether we will issue additional units or other equity securities or whether we will purchase outstanding units;

- whether Enbridge Management or Enbridge Partners will issue additional shares or other equity securities;

- the amount of payments to Enbridge and its affiliates for any services rendered for our benefit;
- the amount of costs that are reimbursable to Enbridge Management or Enbridge and its affiliates by us;
- the enforcement of obligations owed to us by Enbridge Management, our General Partner or Enbridge, including obligations regarding competition between Enbridge and us; and
- the retention of separate counsel, accountants or others to perform services for us and Enbridge Management.

In these and similar situations, any decision by Enbridge Management may benefit one group more than another, and in making such decisions, Enbridge Management may consider the interests of all groups, as well as other factors, in deciding whether to take a particular course of action.

In other situations, Enbridge may take certain actions, including engaging in businesses that compete with us, that are adverse to us and our unitholders. For example, although Enbridge and its subsidiaries are generally restricted from engaging in any business that is in direct material competition with our businesses, that restriction is subject to the following significant exceptions:

- Enbridge and its subsidiaries are not restricted from continuing to engage in businesses, including the normal development of such businesses, in which they were engaged at the time of our initial public offering in December 1991;
- such restriction is limited geographically only to those routes and products for which we provided transportation at the time of our initial public offering;
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us as part of a larger acquisition, so long as the majority of the value of the business or assets acquired, in Enbridge s reasonable judgment, is not attributable to the competitive business; and
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us if that business is first offered for acquisition to us and the board of directors of Enbridge Management and our unitholders determine not to pursue the acquisition.

Since we were not engaged in any aspect of the natural gas business at the time of our initial public offering, Enbridge and its subsidiaries are not restricted from competing with us in any aspect of the natural gas business. In addition, Enbridge and its subsidiaries would be permitted to transport crude oil and liquid petroleum over routes that are not the same as our Lakehead system, even if such transportation is in direct material competition with our business.

We can issue additional common or other classes of units, including additional i-units to Enbridge Management when it issues additional shares, which would dilute your ownership interest.

The issuance of additional common or other classes of units by us, including the issuance of additional i-units to Enbridge Management when it issues additional shares may have the following effects:

- The amount available for distributions on each unit may decrease;
- The relative voting power of each previously outstanding unit may decrease; and

The market price of the Class A common units may decline.

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Additionally, the public sale by our General Partner of a significant portion of the Class A or Class B common units that it currently owns could reduce the market price of the Class A common units. Our partnership agreement allows the General Partner to cause us to register for public sale any units held by the General Partner or its affiliates. A public or private sale of the Class A or Class B common units currently held by our General Partner could absorb some of the trading market demand for the outstanding Class A common units.

Holders of our limited partner interests have limited voting rights.

Our unitholders have limited voting rights on matters affecting our business, which may have a negative effect on the price at which our common units trade. In particular, the unitholders did not elect our General Partner or the directors of our General Partner or Enbridge Management and have no rights to elect our General Partner or the directors of our General Partner or Enbridge Management on an annual or other continuing basis. Furthermore, if unitholders are not satisfied with the performance of our General Partner, they may find it difficult to remove our General Partner. Under the provisions of our partnership agreement, our General Partner may be removed upon the vote of at least 66.67% of the outstanding common units (excluding the units held by the General Partner and its affiliates) and a majority of the outstanding i-units voting together as a separate class (excluding the number of i-units corresponding to the number of shares of Enbridge Management held by our General Partner and its affiliates). Such removal must, however, provide for the election and succession of a new general partner, who may be required to purchase the departing general partner interest in us in order to become the successor general partner. Such restrictions may limit the flexibility of the limited partners in removing our general partner, and removal may also result in the general partner interest in us held by the departing general partner being converted into Class A common units.

We are a holding company and depend entirely on our operating subsidiaries distributions to service our debt obligations.

We are a holding company with no material operations. If we cannot receive cash distributions from our operating subsidiaries, we will not be able to meet our debt service obligations. Our operating subsidiaries may from time to time incur additional indebtedness under agreements that contain restrictions, which could further limit each operating subsidiaries ability to make distributions to us.

The debt securities we issue and any guarantees issued by any of our subsidiaries that are guarantors will be structurally subordinated to the claims of the creditors of any of our operating subsidiaries who are not guarantors of the debt securities. Holders of the debt securities will not be creditors of our operating subsidiaries who have not guaranteed the debt securities. The claims to the assets of these non-guarantor operating subsidiaries derive from our own ownership interest in those operating subsidiaries. Claims of our non-guarantor operating subsidiaries creditors will generally have priority as to the assets of such operating subsidiaries over our own ownership interest claims and will therefore have priority over the holders of our debt, including the debt securities. Our non-guarantor operating subsidiaries creditors may include:

- general creditors;
- trade creditors;
- secured creditors;
- taxing authorities; and
- creditors holding guarantees.

Enbridge Management s discretion in establishing our cash reserves gives it the ability to reduce the amount of cash available for distribution to our unitholders.

Enbridge Management may establish cash reserves for us that in its reasonable discretion are necessary to fund our future operating and capital expenditures, provide for the proper conduct of business, and comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves affect the amount of cash available for distribution to holders of our common units.

Holders of our Series 1 Preferred Units have a distribution preference, which may adversely affect the value the Class A common units

The holders of our Series 1 Preferred Units, or Preferred Units, have a preferential right to distributions prior to distributions to the holders of our Class A common units. For the first eight full quarters ending June 30, 2015, the quarterly cash distributions will not be payable on the Preferred Units and instead accrue and accumulate and are payable on the earlier of May 8, 2018 or on our redemption of the Preferred Units. Thereafter, the distributions will be paid in cash on a quarterly basis. To the extent that we do not pay in full any distribution on the Preferred Units, the unpaid amount will accrue and accumulate until it is paid in full, and no distributions may be made on the common units during that time.

RISKS ARISING FROM OUR PARTNERSHIP STRUCTURE

Total insurance coverage for multiple insurable incidents exceeding coverage limits would be allocated by our General Partner on an equitable basis.

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates through the policy renewal date of May 1, 2014. The comprehensive insurance program also includes property insurance coverage on our assets, except pipeline assets that are not located at water crossings, including earnings interruption resulting from an insurable event. 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 Enbridge, MEP, and another Enbridge subsidiary.

RISKS RELATED TO OUR DEBT AND OUR ABILITY TO MAKE DISTRIBUTIONS

Agreements relating to our debt restrict our ability to make distributions, which could adversely affect the value of our Class A common units, and our ability to incur additional debt and otherwise maintain financial and operating flexibility.

MEP is restricted by its credit facility from making distributions to us. MEP and Midcoast Operating are restricted by their revolving credit facility from declaring or making distributions to us if a revolving credit facility payment, insolvency or financial covenant default then exists or any other default then exists which permits the lenders to accelerate the revolving credit facility, but if no such defaults exist when such distribution is declared, MEP and Midcoast are permitted to make distributions to us even if any such defaults exist when the distribution is made unless MEP or any of its subsidiaries has knowledge that the revolving credit facility has been accelerated.

In addition, we are prohibited from making distributions to our unitholders during (1) the existence of certain defaults under our Credit Facilities or (2) during a period in which we have elected to defer interest payments on the Junior Notes, subject to limited exceptions as set forth in the related indenture. Further, the agreements governing our Credit Facilities may prevent us from engaging in transactions or capitalizing on business opportunities that we believe could be beneficial to us by requiring us to comply with various covenants, including the maintenance of certain financial ratios and restrictions on:

- incurring additional debt;
- entering into mergers or consolidations or sales of assets; and
- granting liens.

Although the indentures governing our senior notes do not limit our ability to incur additional debt, they impose restrictions on our ability to enter into mergers or consolidations and sales of all or substantially all of our assets, to incur liens to secure debt and to enter into sale and leaseback transactions. A breach of any restriction under our Credit Facilities or our indentures could permit the holders of the related debt to declare all amounts outstanding under those agreements immediately due and payable and, in the case of our Credit Facilities, terminate all commitments to extend further credit. Any subsequent refinancing of our current debt or any new indebtedness incurred by us or our subsidiaries could have similar or greater restrictions.

TAX RISKS TO COMMON UNITHOLDERS

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If we were to be treated as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to unitholders could be substantially reduced.

As long as we qualify to be treated as a partnership for federal income tax purposes, we are not subject to federal income tax. Although a publicly-traded limited partnership is generally treated as a corporation for federal income tax purposes, a publicly-traded partnership such as us can qualify to be treated as a partnership for federal income tax purposes under current law so long as for each taxable year at least 90% of our gross income is derived from specified investments and activities. We believe that we qualify to be treated as a partnership for federal income tax purposes because we believe that at least 90% of our gross income for each taxable year has been and is derived from such specified investments and activities. Although we intend to meet this gross income requirement, we may not find it possible, regardless of our efforts, to meet this gross income requirement or may inadvertently fail to meet this gross income requirement. If we do not meet this gross income requirement for any taxable year and the Internal Revenue Service, or IRS, does not determine that such failure was inadvertent, we would be treated as a corporation for such taxable year and each taxable year thereafter. We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or certain other matters affecting us.

Additionally, current law may change so as to cause us to be treated as a corporation for federal income tax purposes without regard to our sources of income or otherwise subject us to entity-level taxation. Legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may be applied retroactively.

If we were to be 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%. Under current law, distributions to unitholders would generally be taxed as corporate distributions, and no income, gain, loss or deduction would flow through to our unitholders. If we were treated as a corporation at the state level, we may also be subject to the income tax provisions of certain states. Moreover, 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 or other forms of taxation. For example, we are required to pay Texas franchise tax at a minimum effective rate of 0.7% of our gross income apportioned to Texas in the prior year.

If we become subject to federal income tax and additional state taxes, the additional taxes we pay will reduce the amount of cash we can distribute each quarter to the holders of our Class A and B common units and the number of i-units that we will distribute quarterly. Therefore, our treatment as a corporation for federal income tax purposes or becoming subject to a material amount of additional state taxes could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units. Moreover, our payment of additional federal and state taxes could materially and adversely affect our ability to make payments on our debt securities.

If the IRS contests our curative tax allocations or other federal income tax positions we take, the market for our Class A common units may be impacted and the cost of any IRS contest will reduce our cash available for distribution or payments on our debt securities.

Our partnership agreement allows curative allocations of income, deduction, gain and loss by us to account for differences between the tax basis and fair market value of property at the time the property is contributed or deemed contributed to us and to account for differences between the fair market value and book basis of our assets existing at the time of issuance of any Class A common units. If the IRS does not respect our curative allocations, ratios of taxable income to cash distributions received by the holders of Class A common units will be materially higher than previously estimated.

The IRS may adopt positions that differ from the positions we have taken or may take on certain tax matters. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we have taken or may take. A court may not agree with some or all of the positions we have taken or may take. Any contest with the IRS may materially and adversely impact the market for our Class A common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our cash available for distribution or payments on our debt securities.

The tax liability of our unitholders could exceed their distributions or proceeds from sales of Class A common units.

Because our unitholders will generally be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income tax and, in some cases, state and local income taxes on their allocable share of our income, even if they do not receive cash distributions from us. Unitholders will not necessarily receive cash distributions equal to the tax on their allocable share of our taxable income.

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

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

As a result of investing in our Class A common units, a unitholder may become subject to state and local taxes and return filing requirements in the states where we or our subsidiaries own property and conduct business.

In addition to federal income taxes, a unitholder 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 or our subsidiaries conduct business or own property now or in the future, even if such unitholder does 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 or our subsidiaries own property and conduct business in the states of Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, Pennsylvania, South Carolina, North Carolina, North Dakota, Oklahoma, Tennessee, Texas, West Virginia, and Wisconsin. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may acquire property or conduct business in additional states or in foreign jurisdictions that impose a personal income tax. It is the responsibility of each unitholder to file all required United States federal, foreign, state and local tax returns.

Ownership of Class A common units raises issues for tax-exempt entities and other investors.

An investment in our Class A common units by tax-exempt entities, such as employee benefit plans, individual retirement accounts, known as IRAs, Keogh plans and other retirement plans, regulated investment companies and foreign persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from United States federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-United States persons will be reduced by withholding taxes at the highest applicable tax rate, and non-United States persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-United States persons should consult their tax adviser before investing in our Class A common units.

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

When we issue additional Class A common 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 Class A 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 income, gain, loss and deduction between the 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 gain from our unitholders sale of Class A common units and could have a negative impact on the value of the Class A 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 our termination as a partnership for United States federal income tax purposes.

We will be considered to have been terminated for United States federal tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in our capital and profits within a twelve-month period. Our 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) for one fiscal year and could result in a significant deferral of depreciation deductions available 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 such 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 tax purposes. If treated as a new partnership for federal tax purposes, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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

Because we cannot match transferors and transferees of our Class A common units and to maintain the uniformity of the economic and tax characteristics of our Class A common units, we have adopted certain depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding Class A common units. A subsequent holder of those Class A common units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). However, because we cannot identify these Class A common units once they are traded by the initial holder, we do not give any subsequent holder of a Class A common unit any such amortization deduction. This approach understates deductions available to those unitholders who own those Class A common units and results in a reduction in the tax basis of those Class A common units by the amount of the deductions that were allowable but were not taken.

The IRS may challenge the manner in which we calculate our unitholder s basis adjustment under Internal Revenue Code Section 743(b). If so, because neither we nor a unitholder can identify the Class A common units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all unitholders selling Class A common units within the period under audit as if all unitholders owned Class A common units with respect to which allowable deductions were not taken. Any position we take that is inconsistent with applicable Treasury regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to this position or other positions we may take could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder s sale of Class A common units and could have a negative impact on the value of the Class A common units or result in audit adjustments to our unitholders tax returns.

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

Because a unitholder whose Class A common units are loaned to a short seller to cover a short sale of Class A common units may be considered as having disposed of those Class A common units, such unitholder may no longer be treated as a partner with respect to those Class A common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those Class A common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those Class A 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 Class A common units.

Item 2. Properties

A description of our properties and maps depicting the locations of our liquids and 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 liquids systems have pumping stations, tanks, terminals and certain other facilities that are located on land that is owned by us in fee and/or used by us under easements, licenses, leases or permits. Additionally, 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.

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.

Item 4. Mine Safety Disclosures

None.

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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 EEP. The quarterly price ranges per Class A common unit and cash distributions paid per unit for 2013 and 2012 are summarized as follows:

	First	Second	Third	Fourth
2013 Quarters				
High	$ 30.68	$ 31.17	$ 33.49	$ 30.96
Low	$ 27.01	$ 28.01	$ 28.97	$ 28.41
Cash distributions paid	$ 0.54350	$ 0.54350	$ 0.54350	$ 0.54350
2012 Quarters				
High	$ 33.85	$ 31.43	$ 31.12	$ 30.64
Low	$ 30.42	$ 27.75	$ 28.26	$ 26.88
Cash distributions paid	$ 0.53250	$ 0.53250	$ 0.54350	$ 0.54350

On February 14, 2014, the last reported sales price of our Class A common units on the NYSE was $27.69. At January 31, 2014, there were approximately 92,000 Class A common unitholders, of which there were approximately 1,100 registered Class A common unitholders of record. There is no established public trading market for our Class B common units, all of which are held by the General Partner, or our i-units, all of which are held by Enbridge Management.

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Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. 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,				
	2013	2012	2011	2010	2009
	(in millions, except per unit amounts)				
Income Statement Data: (2)(5)(6)(7)(8)(9)(10)(11)					
Operating revenues	$ 7,117.1	$ 6,706.1	$ 9,109.8	$ 7,736.1	$ 5,731.8
Operating expenses	6,676.7	5,812.9	8,113.0	7,608.8	5,115.2
Operating income	440.4	893.2	996.8	127.3	616.6
Interest expense	320.4	345.0	320.6	274.8	228.6
Allowance for equity used during construction	43.1	11.2		15.3	12.6
Other income (expense)	16.0	(1.2)	6.5	2.2	0.8
Income tax expense	18.7	8.1	5.5	7.9	8.5
Noncontrolling interest	88.3	57.0	53.2	60.6	11.4
Series 1 preferred unit distributions	58.2				
Accretion of discount on Series 1 preferred units	9.2				
Income (loss) from continuing operations attributable to general and limited partnership interests	$ 4.7	$ 493.1	$ 624.0	$ (198.5)	$ 381.5
Net income (loss) allocable to limited partner interest	$ (122.7)	$ 369.2	$ 520.5	$ (260.1)	$ 260.8
Income (loss) from continuing operations per limited partner unit (basic and diluted) (1)	$ (0.39)	$ 1.27	$ 1.99	$ (1.09)	$ 1.12
Income (loss) from continuing operations per limited partner unit (diluted) (1)	$ (0.39)	$ 1.27	$ 1.99	$ (1.09)	$ 1.12
Cash distributions paid per limited partner unit	$ 2.1740	$ 2.1520	$ 2.0925	$ 2.0240	$ 1.9800
Financial Position Data (at year end): (2)(3)(4)(5)(6)(7)(8)(9)					
Property, plant and equipment, net	$ 13,176.8	$ 10,937.6	$ 9,439.4	8,641.6	7,716.7
Total assets	14,901.5	12,796.8	11,370.1	10,441.0	8,988.3
Long-term debt, excluding current maturities	4,777.4	5,501.7	4,816.1	4,778.9	3,791.2
Notes payable to General Partner	318.0	330.0	342.0	347.4	269.7
Partners capital:					
Series 1 preferred units	1,160.7				
Class A common units	2,979.0	3,590.2	3,386.7	2,641.0	2,884.9
Class B common units	65.3	83.9	82.2	64.9	78.6
Class C units (12)					
i-units	1,291.9	801.8	728.6	579.1	588.8
General Partner	301.5	299.0	285.6	256.8	251.1
Accumulated other comprehensive income (loss)	(76.6)	(320.5)	(316.5)	(121.7)	(74.6)
Noncontrolling interest	1,975.6	793.5	445.5	465.4	341.1
Partners capital	$ 7,697.4	$ 5,247.9	$ 4,612.1	$ 3,885.5	$ 4,069.9
Cash Flow Data: (2)(3)(4)(5)(6)(7)(8)					
Cash flows provided by operating activities	$ 1,212.4	$ 851.0	$ 1,045.6	$ 377.9	$ 728.4

Cash flows used in investing activities	2,642.9	1,906.6	1,099.0	1,427.8	1,173.6
Cash flows provided by financing activities	1,367.4	860.6	331.4	1,051.2	248.9
Additions to property, plant and equipment, and acquisitions included in investing activities, net of cash acquired	2,410.8	1,739.9	1,091.8	1,429.5	1,292.1

(1) The allocation of net income (loss) to the General Partner in the following amounts has been deducted before calculating income (loss) from continuing operations per limited partner unit: 2013, $144.1 million; 2012, $129.3 million; 2011, $104.5 million; 2010, $61.6 million; and 2009, $57.1 million.

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(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.
November 2009	Disposition of natural gas pipelines located predominately outside of Texas.
May 2009	Acquisition of a portion of a crude oil pipeline system running from Flanagan, Illinois to Griffith, Indiana.
January 2009	Disposition of an offshore natural gas pipeline.

(3) Our financial position and cash flow data include the effect of the following debt issuances and debt repayments:

Date of Debt Issuance	Debt Type	Amount of Debt Issuance
September 2011	4.200% Senior Notes	$ 600
September 2011	5.500% Senior Notes	$ 150
September 2010	5.500% Senior Notes	$ 400
March 2010	5.200% Senior Notes	$ 500

For the year ended December 31, 2013 we made the following debt repayments:
$200.0 million of our 4.750% senior notes.

For the year ended December 31, 2012 we made the following debt repayments:
$100.0 million of our 7.900% senior notes.

For the year ended December 31, 2011 we made the following debt repayments:
$31.0 million of our First Mortgage Notes;

For the year ended December 31, 2010 we made the following debt repayments:
$31.0 million of our First Mortgage Notes;

For the year ended December 31, 2009 we made the following debt repayments:
$31.0 million of our First Mortgage Notes;
$214.7 million of our Zero Coupon Notes;
$130.0 million of our Hungary Note; and
$175.0 million of our 4.000% senior notes.

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

Date of Unit Issuance	Class of Limited Partnership Interest	Number of Units Issued	Net Proceeds Including General Partner Contribution
September 2012	Class A	16,100,000	$ 456.2
May 2012	Class A	64,464	$ 2.0
2011 Equity Distribution Agreement issuances	Class A	3,084,208	$ 95.5
December 2011	Class A	9,775,000	$ 298.1
September 2011	Class A	8,000,000	$ 222.9
July 2011	Class A	8,050,000	$ 238.6
January 2011	Class A	50,650	$ 1.6

2010 Equity Distribution Agreement issuances	Class A	2,237,402	$	59.9
November 2010	Class A	11,960,000	$	354.8
October 2009	Class A	42,490	$	1.0

All unit issuances prior to the April 2011 stock split have been retrospectively adjusted to be comparable.

In January 2011 and May 2012 we issued Class A common units in connection with land acquisitions.

(5) Our income statement, financial position and cash flow data include the effect of the following distributions:

Fiscal Year		Amount of Distribution of i-units to i-unit Holders		Amount of Distribution of Class C Units to Class C Unitholders		Retained from General Partner		Distribution of Cash
2013	$	113.8	$		$	2.3	$	708.9
2012	$	85.0	$		$	1.7	$	660.3
2011	$	75.7	$		$	1.5	$	565.7
2010	$	68.3	$		$	1.4	$	481.6
2009	$	61.1	$	60.3	$	2.4	$	395.0

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The quarterly in-kind distributions of 3.8 million, 2.6 million, 2.4 million, 2.5 million and 3.3 million i-units during 2013, 2012, 2011, 2010 and 2009, respectively, in lieu of cash distributions; and

The quarterly in-kind distributions of 1.6 million Class C units during 2009, in lieu of cash distributions.

(6) In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline, with several of our affiliates and affiliates of Enbridge. In exchange for a 66.67% ownership interest in the Alberta Clipper Pipeline, Enbridge, through our General Partner, funded approximately two-thirds of both the debt financing and equity requirement for the project in return for approximately two-thirds of the earnings and cash flows. For our 33.33% ownership of the Alberta Clipper Pipeline, we funded approximately one-third of the debt financing and required equity of the project, for which we are entitled to approximately one-third of the project s earnings and cash flows. As a result of this joint funding arrangement, 66.67% of earnings associated with the Alberta Clipper Pipeline are attributable to our General Partner and presented as Noncontrolling interest in our consolidated statements of income and consolidated statement of financial position.

In August 2009, we applied the provisions of regulatory accounting to our Alberta Clipper Pipeline. In conjunction with our application of the provisions of regulatory accounting, we recorded an allowance for equity during construction, referred to as AEDC, of $15.3 million and $12.6 million for the years ended December 31, 2010 and 2009, which is recorded in Other income in our consolidated statements of income. The Alberta Clipper Pipeline was put into service in 2010; therefore no AEDC was recorded in 2011.

(7) Operating results for the years ended December 31, 2013, 2012 and 2011, were affected by costs incurred in connection with the crude oil releases on Lines 6A and 6B of our Lakehead system. We estimate that in connection with these incidents for the years ended December 31, 2013, 2012, 2011 and 2010 we will incur aggregate gross costs of $302.0 million, $55.0 million, $218.0 million and $595.0 million, respectively, for emergency response, environmental remediation and cleanup activities associated with the crude oil releases, before insurance recoveries and excluding fines and penalties. In addition, for the years ended December 31, 2013, 2012 and 2011, we recognized $42.0 million, $170.0 million and $335.0 million, respectively, in insurance recoveries related to such incidents. Furthermore, during the period the pipelines were not in service in 2010, our operating revenues were lower by approximately $16 million as a result of the volumes that we were unable to transport. We do not maintain insurance coverage for interruption of our operations, except for water crossings, and therefore we will not recover the revenues lost while Lines 6A and 6B were not in service. Based on our current estimate of costs associated with these crude oil releases through December 31, 2013, Enbridge and its affiliates, including us, have exceeded the limits of coverage under this insurance policy; however we are in legal discussions to recover the remaining $103.0 million balance of our aggregate insurance coverage, but there can be no assurance that we will collect the remaining insurance balance.

(8) Operating results for the year ended December 31, 2011 were affected by $52.2 million we received in the second quarter of 2011 for the settlement of a dispute related to oil measurement losses, which we recognized as a reduction to operating expenses.

(9) Operating results for the year ended December 31, 2011 were affected by $18.0 million of additional expense we recognized in the fourth quarter of 2011, related to accounting misstatements and accounting errors as discussed in Note 14. *Trucking and NGL Marketing Business Accounting Matters*.

(10) Operating results for the year ended December 31, 2012 were affected by $8.9 million of estimated costs accrued in connection with the July 27, 2012 crude oil release on Line 14 of our Lakehead system as discussed in Note 13. *Commitments and Contingencies*. The $10.5 million accrual is inclusive of approximately $1.6 million of lost revenue and excludes any potential fines or penalties. We will be pursuing claims under our insurance policy, although we do not expect any recoveries to be significant.

(11) Since October 2011, we and Enbridge have announced multiple expansion projects that will provide increased access to refineries in the United States Upper Midwest and in Canada in the provinces of, Ontario, and Quebec for light crude oil produced in western Canada and the United States. These projects collectively referred to as the Eastern Access Projects and Mainline Expansion Projects, will cost approximately $2.5 billion and $2.4 billion, respectively. These projects have been undertaken on a cost-of-service basis and are funded 75% by our General Partner and 25% by the Partnership under the Eastern Access Joint Funding Agreement and Mainline Expansion Joint Funding Agreement, as amended. In conjunction with our application of the provisions of regulatory accounting, we recorded AEDC of $33.3 million and $4.7 million for the years ended December 31, 2013 and 2012, respectively, which is recorded in Other income in our consolidated statements of income.

(12)

In October 2009, we effected the conversion of all our outstanding Class C units into Class A common units in accordance with the terms of our partnership agreement.

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Item 7. Management 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 beginning in Item 8. *Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

RESULTS OF OPERATIONS OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

In May 2013, we formed a new subsidiary, Midcoast Energy Partners, L.P., or MEP. On November 13, 2013, MEP completed its initial public offering, or the Offering, of Class A common units, representing limited partner interests in MEP. On the same date, in connection with the closing of the Offering, certain transactions, among others, occurred pursuant to which we effectively conveyed to MEP all of our limited liability company interests in the general partner of the operating subsidiary of MEP, or Midcoast Operating, and a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units and MEP Subordinated Units, approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the contributed businesses, and a right to receive $323.4 million in cash. In addition, in connection with the Offering and the closing of the underwriters exercise of its over-allotment option, we received $47.0 million from MEP in its redemption of 2,775,000 of MEP Class A common units from us. At December 31, 2013, we owned 2.893% of the outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP s general partner and 61% of the limited partner interests in Midcoast Operating.

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The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31, 2013, 2012 and 2011:

	December 31,		
	2013	2012 (in millions)	2011
Operating Income (loss)			
Liquids	$ 392.6	$ 706.8	$ 816.2
Natural Gas	57.7	200.1	183.6
Marketing	(2.3)	(11.4)	(0.8)
Corporate, operating and administrative	(7.6)	(2.3)	(2.2)
Total Operating Income	440.4	893.2	996.8
Interest expense	320.4	345.0	320.6
Allowance for equity used during construction	43.1	11.2	
Other income (expense)	16.0	(1.2)	6.5
Income tax expense	18.7	8.1	5.5
Net income	160.4	550.1	677.2
Less: Net income attributable to:			
Noncontrolling interest	88.3	57.0	53.2
Series 1 preferred unit distributions	58.2		
Accretion of discount on Series 1 preferred units	9.2		
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 4.7	$ 493.1	$ 624.0

Contractual arrangements in our Liquids, Natural Gas and Marketing segments expose us to market risks associated with changes in commodity prices where we receive crude oil, 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. These fluctuations can be significant if commodity prices experience significant volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in crude oil, natural gas and NGL 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.

Summary Analysis of Operating Results

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. These systems largely consist of FERC-regulated interstate crude oil and liquid petroleum pipelines, gathering systems and storage facilities. The Lakehead system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. Our Liquids systems generate revenues primarily from charging shippers a rate per barrel to gather, transport and store crude oil and liquid petroleum.

The operating income of our Liquids business for the year ended December 31, 2013 decreased $314.2 million, as compared with the same period in 2012, primarily due to the following:

Increased environmental costs, net of insurance recoveries, of $365.0 million for the year ended December 31, 2013 when compared to the same period of 2012;

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- Increased Operating and administrative expenses of $104.7 million primarily due to:

  - Increased cost related to hydrotesting on Line 14 of $57.7 million;

  - Increased workforce related costs and other allocated expenses of $14.7 million;

  - Increased property tax expenses of $10.2 million; and

  - Increased facility integrity costs of $5.9 million; and

- Increased depreciation expense of $34.9 million for the year ended December 31, 2013, directly attributable to additional assets placed into service since 2012.

The above factors were partially offset for the year ended December 31, 2013, as compared with the year ended December 31, 2012 due to:

- Increased operating revenue of $157.4 million due to higher indexed tariff rates on our Lakehead, North Dakota and Ozark systems and increased SEPII rates from recovery of integrity costs;

- Increased operating revenue of $41.7 million due to revenue from ship or pay agreements on the North Dakota systems;

- Increased operating revenue of $19.4 million for fees collected from our Berthold Rail system; and

- Increased operating revenue of $16.4 million for fees collected from our Cushing storage terminal facility;

Natural Gas

Our natural gas business includes natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities. Revenues for our natural gas 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 natural gas business 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 Natural Gas segment for the year ended December 31, 2013 decreased $142.4 million, as compared with the year ended December 31, 2012, primarily due to the following:

- Decreased gross margin of approximately $57.0 million due to reduced pricing spreads between the NGLs purchased at Conway and the NGLs sold at Mont Belvieu market hubs;

- Decreased gross margin from keep-whole processing earnings of $27.1 million due to a decline in total NGL production;

Decreased gross margin of approximately $27.0 million due to reduced production volumes;

Decreased gross margin of approximately $8.0 million due to changes in estimated to actual adjustments;

Decreased gross margin of $7.2 million related to prior year revenue allocation corrections. These allocation corrections provided additional revenues recognized during the year ended December 31, 2012, with no similar additional revenues recognized during the year ended December 31, 2013;

- Decreased gross margin of $4.5 million in non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment;

- Decreased gross margin of approximately $4.0 million due to changes in physical measurement adjustments; and

- Increased depreciation expense of $8.3 million due to additional assets that were placed into service in 2012 and 2013.

The above factors were partially offset for the year ended December 31, 2013, as compared with the year ended December 31, 2012 due to:

- Decreased current year costs of $7.5 million for the investigation related to accounting misstatements at our trucking and NGL marketing subsidiary recorded for the year ended December 31, 2012, with no similar costs recorded during the year ended December 31, 2013;

- Decreased operational related costs of $6.8 million due to favorable spending for rents, maintenance, supplies and other outside services; and

- Decreased current year costs of $4.3 million for the prior year write down of surplus materials associated with deferred portions of a development project on our East Texas system.

Marketing

Our Marketing segment provides supply, transmission, storage and sales services to producers and wholesale customers on our natural gas gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Our Marketing activities are primarily undertaken to realize incremental revenue on gas purchased at the wellhead, increase pipeline utilization and provide other services that are valued by our customers.

The operating results of our Marketing business for the year ended December 31, 2013 increased $9.1 million, as compared with the year ended December 31, 2012. The increase in operating results of our Marketing business was the improvement of natural gas price differences between the supply and market locations where we buy and sell natural gas. These larger differences enabled us to increase our margins in certain circumstances. This was facilitated by an increase in natural gas prices for the year ended December 31, 2013, when compared to the year ended December 31, 2012.

Also contributing to the increase in operating results of our Marketing segment, for the year ended December 31, 2013, was the expiration of certain transportation fees for natural gas being transported on a third party pipeline. Additionally, we recorded only $0.4 million of non-cash charges in inventory to reduce the cost basis of our natural gas inventory to net realizable value, for the year ended December 31, 2013, compared with $2.0 million of similar charges recorded for the year ended December 31, 2012.

Derivative Transactions and Hedging 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 and interest rates and 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 or interest rates. We record all derivative instruments in our consolidated financial statements at fair market value pursuant

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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 follows:

Liquids segment commodity-based derivatives Operating revenue and Power

Natural Gas and Marketing segments commodity-based derivatives Cost of natural gas and Operating revenue

Corporate interest rate derivatives Interest expense

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 derivative fair value net gains and losses associated with the changes in fair value of our derivative financial instruments:

	December 31,		
	2013	**2012**	**2011**
		(in millions)	
Liquids segment			
Non-qualified hedges	$ (3.9)	$ 1.3	$ 14.4
Natural Gas segment			
Hedge ineffectiveness	3.3	3.1	(5.3)
Non-qualified hedges	(3.5)	1.2	21.1
Marketing			
Non-qualified hedges	(2.8)	(3.1)	0.7
Commodity derivative fair value net gains (losses)	(6.9)	2.5	30.9
Corporate			
Hedge ineffectiveness	(21.5)	(20.5)	(0.3)
Non-qualified interest rate hedges	(0.2)	(0.5)	(0.5)
Derivative fair value net gains (losses)	$ (28.6)	$ (18.5)	$ 30.1

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RESULTS OF OPERATIONS BY SEGMENT

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. We provide a detailed description of each of these systems in Item 1. *Business*. The following tables set forth the operating results and statistics of our Liquids segment for the periods presented:

		December 31,	
	2013	**2012**	**2011**
		(in millions)	
Operating Results			
Operating revenues	$ 1,519.9	$ 1,345.8	$ 1,285.4
Environmental costs, net of recoveries	273.7	(91.3)	(112.9)
Oil measurement adjustments	(26.7)	(11.5)	(63.4)
Operating and administrative	487.7	383.0	303.6
Power	147.7	148.8	144.8
Depreciation and amortization	244.9	210.0	197.1
Operating expenses	1,127.3	639.0	469.2
Operating income (loss)	$ 392.6	$ 706.8	$ 816.2
Operating Statistics			
Lakehead system:			
United States[(1)]	1,427	1,405	1,327
Province of Ontario[(1)]	389	385	373
Total Lakehead system delivery volumes[(1)]	1,816	1,790	1,700
Barrel miles (billions)	487	480	450
Average haul (miles)	735	732	725
Mid-Continent system delivery volumes[(1)]	201	223	226
North Dakota system:			
Trunkline	168	203	193
Gathering	3	3	4
Total North Dakota system delivery volumes[(1)]	171	206	197
Total Liquids segment delivery volumes[(1)]	2,188	2,219	2,123

(1) Average barrels per day in thousands.

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

The operating revenue of our Liquids segment increased $174.1 million for the year ended December 31, 2013 when compared with the same period in 2012, primarily due to the filing of tariffs that became effective July 1, 2013, April 1, 2013 and July 1, 2012 to increase the rates for our Lakehead, North Dakota and Ozark systems with Federal Energy Regulatory Commission, or FERC. The increase in rates accounted for $157.4 million of the increase in operating revenue for the year ended December 31, 2013 when compared to December 31, 2012. The rate increases that became effective July 1, 2013 and July 1, 2012 resulted from application of the index allowed by FERC. The rate increase effective April 1, 2013 primarily resulted from the annual tariff rate adjustment for our Lakehead system to reflect our projected costs and throughput for 2013, true-ups for the prior year for the Lakehead system and recovery of costs related to several of our major capital projects and SEPII integrity costs on our Lakehead system.

Operating revenue also increased for the year ended December 31, 2013, when compared with the same period in 2012, due to an increase of $41.7 million in ship or pay contracts on our Bakken system. These long-term ship-or-pay contracts contain make-up-rights. Make-up-rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiration periods. We recognize revenue associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Additionally, our operating revenue increased during the year ended December 31, 2013, when compared to the same period in 2012, due to an increase of $19.4 million from our Berthold Rail System that was completed in March 2013. We also had increased operating revenue of $16.4 million from our storage facilities for the year ended December 31, 2013 as compared to 2012 primarily due to 1.3 million and 1.8 million barrels of tankage being placed into service at our Cushing facility during the second and fourth quarters of 2012 respectively.

Operating revenue of our Liquids business was negatively impacted for the year ended December 31, 2013 when compared with the same period in 2012 by $29.7 million due to lower average daily delivery volumes on our North Dakota and Mid-Continent systems. The total average daily deliveries from our liquid systems decreased to 2.188 million barrels per day, or Bpd, for the year ended December 31, 2013 from 2.219 million Bpd for the year ended 2012. The decrease was driven by lower North Dakota volumes which decreased due to large pricing differences that incented some shippers to move by rail rather than by pipeline as well as pressure restrictions on our Mid-Continent system. Decreases on our North Dakota and Mid-Continent systems were offset by increasing volumes on our Lakehead system which realized higher volumes due to the growth of the Canadian Oil Sands. Operating revenue was also negatively impacted by $24.9 million as a result of regulatory true-ups related to the Southern Access surcharge embedded in the Lakehead toll revenues. Delivery volumes were forecasted to be higher in the April 1, 2013 toll filing as compared to actual volumes causing this negative impact. These amounts will be trued up and recovered in the Lakehead tariff that will be effective April 1, 2014.

Additionally, our operating revenue decreased as a result of increases of $5.6 million of non-cash, mark-to-market net losses related to derivative financial instruments. We use forward contracts to hedge a portion of the crude oil we expect to receive from our customers as a pipeline loss allowance as part of the transportation of their crude oil. We subsequently sell this crude oil at market rates. We use derivative financial instruments which fix the sales price we will receive in the future for the sale of this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges.

Environmental costs, net of recoveries, increased $365.0 million for the year ended December 31, 2013 when compared with the same period in 2012, of which $375.0 million, net of recoveries, is related to the Line 6B crude oil release. During the year ended December 31, 2013, we recognized $42.0 million in insurance recoveries in connection with the Line 6B crude oil release compared to $170.0 million for the same period in 2012. We increased our total incident cost accrual by $302.0 million for the year ended December 31, 2013, compared to an increase of $55.0 million for the year ended December 31, 2012. This was offset by a decrease in environmental costs of $10.0 million related to other various crude oil releases for the year ended December 31, 2013 as compared to the same period in 2012.

The operating and administrative expenses of our Liquids business increased $104.7 million for the year ended December 31, 2013 when compared with the same period in 2012 primarily due to the increased costs of $57.7 million related to a hydrostatic test we performed on Line 14. After the July 27, 2012 release of crude oil on Line 14, the PHMSA issued a Corrective Action Order on July 30, 2012 and an amended Corrective Action Order on August 1, 2012, which we refer to collectively as the PHMSA Corrective Action Order. The PHMSA

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Corrective Action Order required us to take certain corrective actions, some of which were done during 2013 and some are still ongoing, as part of an overall plan for our Lakehead system. As part of this plan, we performed hydrostatic testing of Line 14 during the third quarter of 2013. As discussed above, a portion of these costs have been recovered through our Lakehead tariff and the remainder will be recovered in future periods.

Operating and administrative expenses for our Liquids business increased also due to the following:

- Increased workforce related costs and other allocated expenses of $14.7 million;
- Increased property tax expenses of $10.2 million; and
- Higher costs related to our integrity program of $5.9 million.

Over the past several years, we have focused on achieving pipeline industry leading performance in the areas of public and worker safety, operations and pipeline systems integrity. We have implemented initiatives such as our operational risk management plan, which puts emphasis on areas such as emergency response, pipeline integrity, pipeline control and leak detection systems and we have increased our internal inspection frequency and hired more personnel in field operations to ensure we meet this overriding objective. These efforts have increased our operating cost spending relative to prior years. We expect these costs to be an ongoing obligation to achieve and maintain our goal of best in class safety performance.

The increase in depreciation expense of $34.9 million for the year ended December 31, 2013 is directly attributable to the additional assets we have placed in service during 2013 and 2012. Included in this change is a decrease of $4.2 million as a result of a depreciation study we completed during the fourth quarter of 2013 for our North Dakota and Ozark systems. The asset life was extended due to additional reserve growth and pipeline connectivity needs. The impact on future periods will be an annual reduction in depreciation expense of $16.8 million.

Year ended December 31, 2012 compared with year ended December 31, 2011

The operating revenue of our Liquids segment increased for the year ended December 31, 2012 when compared with the same period in 2011, partially due to higher average daily delivery volumes on our Lakehead and North Dakota systems when compared to the same period in 2011. The overall increase in average delivery volumes on our systems increased operating revenues by $25.1 million for our Liquids segment. The total average daily deliveries from our liquid systems increased over 4%, to 2.219 million barrels per day, or Bpd, for the year ended December 31, 2012 from 2.123 million Bpd for the year ended 2011. The increase in average deliveries on our liquids systems was primarily derived from increases of crude oil supplies from conventional sources as well as strong refinery utilization in PADD II.

Our operating revenue was positively impacted by the filing of tariffs to increase the rates for our Lakehead, North Dakota and Ozark systems with Federal Energy Regulatory Commission, or FERC, that became effective July 1, 2012. These rate increases resulted from application of the index allowed by FERC. This change in index comprises approximately $17.0 million of the increase in operating revenue for the year ended December 31, 2012 when compared to the same period in 2011.

Our operating revenue increased by $14.9 million during the year ended December 31, 2012 due to the collection of fees from our Cushing storage terminal facilities, with the majority of these incremental revenues coming from storage facilities which were placed into service in 2012.

In addition, our operating revenues increased by $11.8 million due to higher recovery of capital costs we recovered through our annual tolls under our Facilities Surcharge Mechanism, or FSM, related to the Line 6B Pipeline Integrity Plan for the year ended December 31, 2012 compared to the same period in 2011.

The operating revenue of our Liquids business was negatively impacted for the year ended December 31, 2012 when compared with the same period in 2011 by a $13.1 million decrease in unrealized, non-cash, mark-to-market net gains for year ended December 31, 2012, related to derivative financial instruments as compared with the same period in 2011, due to changes in average forward prices of crude oil for the respective periods. We use forward contracts to hedge a portion of the crude oil we expect to receive from our customers as a pipeline loss allowance as part of the transportation of their crude oil. We subsequently sell this crude oil at market rates. We use derivative financial instruments to fix the sales price we will receive in the future for the sale of this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges.

The operating and administrative expenses of our Liquids business increased $79.4 million for the year ended December 31, 2012 when compared with the same period in 2011 primarily due to the following:

- Increased workforce related costs and other allocated expenses of $28.2 million;
- Increased support costs of $16.0 million related to professional and regulatory expenses, maintenance, supplies and other outside services;
- Increased property tax expenses of $14.8 million; and
- Higher costs related to our integrity program of $11.2 million.

Over the past several years, Enbridge and the Partnership have focused on achieving pipeline industry leading performance in the areas of public and worker safety, operations and pipeline systems integrity. We have implemented initiatives such as our operational risk management plan, which puts emphasis on areas such as emergency response, pipeline integrity, pipeline control and leak detection systems as well as we have increased our internal inspection frequency and hired more personnel in field operations to ensure we meet this overriding objective. These efforts have increased our operating cost spending relative to prior years. For example, during 2012, we worked with an industry leading safety consultant to assist us with enhancing safety structure and processes. All of these programs and initiatives are essential to our long-term operations. We expect these costs to be an ongoing obligation to achieve and maintain best in class safety performance.

Environmental costs, net of recoveries, increased $21.6 million for the year ended December 31, 2012 when compared with the same period in 2011 of which $5.0 million, net of recoveries, is related to the Line 6B crude oil release. During the year ended December 31, 2012, we recognized $170.0 million in insurance recoveries in connection with the Line 6B crude oil release compared to $335.0 million for the same period in 2011. We increased our total incident cost accrual by $55.0 million for the year ended December 31, 2012, compared to an increase of $215.0 million for the year ended December 31, 2011. An additional $8.9 million of environmental costs were recognized related to the Line 14 crude oil release on our Lakehead system near Grand Marsh, Wisconsin that occurred on July 27, 2012. We also recognized additional environmental costs in aggregate of $7.7 million related to other minor crude oil releases.

For the year ended December 31, 2011, we settled a dispute with a shipper on our Lakehead crude oil pipeline system, which we recognized in 2011, for oil measurement adjustments we had previously experienced in prior years. We recorded $52.2 million to oil measurement adjustments, which is a reduction to operating expenses for the year ended December 31, 2011. There were no such adjustments for the year ended December 31, 2012.

Power costs increased $4.0 million for the year ended December 31, 2013, compared with the same period in 2011. The increase in power costs is primarily associated with the higher volumes of crude oil transported on our Lakehead system.

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The increase in depreciation expense of $12.9 million for the year ended December 31, 2013 is directly attributable to the additional assets we have placed in service since the same period in 2012.

Future Prospects Update for Liquids

Our Lakehead system is well positioned as the primary transporter of Western Canadian crude oil and continues to benefit from the growing production of crude oil from the Alberta Oil Sands, as well as recent development in Tight Oil production in North Dakota. The National Energy Board, or NEB, estimated that total production from the WCSB averaged approximately 3.3 million Bpd in 2013 and 3 million in 2012. Meanwhile, strong production growth from the Bakken formation has increased tight oil available from North Dakota to nearly 780,000 Bpd in 2013, as compared to 600,000 Bpd in 2012. With access to growing supply from the WCSB and Bakken formation, the Lakehead system will remain an important conduit for crude oil to U.S. markets for years to come. Volumes of WCSB crude oil production currently exceed those from Iraq and Venezuela, key members of the Organization of Petroleum Exporting Countries, or OPEC.

Based on forecasted growth in Western Canadian crude oil production and completion of upgrader expansions and increased bitumen production, our Lakehead system deliveries are expected to grow beyond the 1.8 million Bpd of actual deliveries in 2013. The ability to increase deliveries and to expand our Lakehead system in the future will ultimately depend upon a number of factors. The investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers expectations of crude oil and natural gas prices, future operating costs, United States demand and availability of markets for produced crude oil. Higher crude oil production from the WCSB should result in higher deliveries on our Lakehead system. Deliveries on our Lakehead system are also affected by periodic maintenance, refinery turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, our Lakehead system.

Similar to our Lakehead system, our North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States and the ability of crude oil producers to maintain their crude oil production and exploration activities. Due to increased exploration of the Bakken and Three Forks formations within the Williston Basin, the state of North Dakota reported production levels of 932,000 Bpd as of September 2013, with projections of exceeding 1 million Bpd in early 2014.

The chief transportation competition to our North Dakota system is rail. Initially considered a niche or alternative form of transportation, rail currently represents more than 75% of the total Bakken crude exported from North Dakota. Rail provides some advantages to pipeline transportation alternatives, but its recent dominance in market share is considered to be primarily driven by extreme price differentials Bakken crudes received vis-à-vis Brent or other non-Cushing based oil markets. Future Enbridge pipeline expansions and enhanced market access to eastern Canadian markets and eastern PADD II are expected to decrease current crude oil price differentials. As pipeline expansion projects create more export capacity from the Bakken, other pipeline projects provide increased access to more refinery markets across the United States, and price differentials return to long term average levels, more North Dakota customers are expected to shift their volumes back to pipelines as the primary transportation option given the economies of scale and other advantages that pipeline transportation enjoy vis-à-vis rail.

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The table below summarizes the Partnership s commercially secured projects for the Liquids segment, which have been recently placed into service or will be placed into service in future periods:

Projects	Total Estimated Capital Costs	In-Service Date	Funding
	(in millions)		
Eastern Access Projects			
Line 5, Line 62 Expansion, Line 6B Replacement	$ 2,070	2013 2014(4)	Joint(1)
Eastern Access Upsize Line 6B Expansion	365	Early 2016	Joint(1)
U.S. Mainline Expansions			
Line 61 (ME phase 1)	215	Q3 2014	Joint(2)
Line 67 (ME phase 1)	205	Q3 2014(3)	Joint(2)
Chicago Area Connectivity (Line 62 twin)	495	Late 2015	Joint(2)
Line 61 (ME phase 2)	1,250	Mid 2015, 2016	Joint(2)
Line 67 (ME phase 3)	240	2015	Joint(2)
Line 6B 75-mile Replacement Program	390	Q2 2013 Q1 2014(5)	EEP
Berthold Rail	135	Q1 2013	EEP
Bakken Pipeline Expansion	300	Q1 2013	EEP
Bakken Access Program	100	Mid 2013	EEP
Sandpiper Project	2,600	Early 2016	Joint(6)

(1) Jointly funded 25% by the Partnership and 75% by our General Partner under Eastern Access Joint Funding agreement. Estimated capital costs are presented at 100% before our General Partner s contributions.

(2) Jointly funded 25% by the Partnership and 75% by our General Partner under Mainline Expansion Joint Funding agreement. Estimated capital costs are presented at 100% before our General Partner s contributions.

(3) Delayed, however, throughput impacts expected to be substantially mitigated by temporary system optimization actions.

(4) As of December 31, 2013, the following projects related to the Eastern Access Projects have been put into service: (1) Line 5 and (2) Line 62 Expansion.

(5) As of December 31, 2013, the Line 6B 75-mile Replacement Program has been put into service with only two 5-mile segments remaining to be put into service in Q1 2014.

(6) As of November 25, 2013, the Sandpiper Project is funded 62.5% by the Partnership and 37.5% by Williston Basin Pipe Line LLC under the North Dakota Pipeline Company Amended and Restated Limited Liability Company Agreement.

Light Oil Market Access Program

On December 6, 2012, we and Enbridge announced our plans to invest in a Light Oil Market Access Program to expand access to markets for growing volumes of light oil production. This program responds to significant recent developments with respect to supply of light oil from U.S. north central formations and western Canada, as well as refinery demand for light oil in the U.S. Midwest and eastern Canada. The Light Oil Market Access Program includes several projects that will provide increased pipeline capacity on our North Dakota regional system, further expand capacity on our U.S. mainline system, upsize the Eastern Access Project, enhance Enbridge s Canadian mainline terminal capacity and provide additional access to U.S. Midwestern refineries.

Sandpiper Project

Included in the Light Oil Market Access Program is the Sandpiper Project which will expand and extend the North Dakota feeder system by 225,000 Bpd to a total of 580,000 Bpd. The original proposed expansion involved construction of an approximate 600-mile 24-inch diameter line from Beaver Lodge Station near Tioga, North Dakota, to the Superior, Wisconsin mainline system terminal. In September 2013, a scope modification was made to increase the twin line diameter from 24-inches to 30-inches between Clearbrook and Superior. The new line will twin the 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal, adding 225,000 Bpd of capacity on the twin line between Tioga and Clearbrook and 375,000 Bpd between Clearbrook and Superior. As a result of scope modifications, the expected capital cost increased by approximately $100 million, and the Sandpiper project is now expected to cost approximately $2.6 billion.

In November 2013, we announced that Marathon Petroleum Corporation, or MPC, has been secured as an anchor shipper for the Sandpiper project. As part of the arrangement, the Partnership, through its subsidiary, North Dakota Pipeline Company LLC, or NDPC, formerly known as Enbridge Pipelines (North Dakota) LLC, and Williston Basin PipeLine LLC, or Williston, an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of the Sandpiper Project construction and have the option to participate in other growth projects (not to exceed $1.2 billion in aggregate). As a result of Williston funding part of Sandpiper s construction, Williston will obtain an approximate 27% equity interest in NDPC at the in service date of Sandpiper targeted for early 2016.

We filed a petition with the FERC to approve recovering Sandpiper s costs through a surcharge to the Enbridge Pipelines (North Dakota) LLC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. On March 22, 2013, the FERC denied the petition on procedural grounds. We plan to re-file the petition with modifications to address the FERC s concerns. Furthermore, in November 2013, we also announced an open season to solicit commitments from shippers for capacity created by the Sandpiper Project. The open season closed in late January 2014 with the receipt of a further capacity commitment which can be accommodated within the planned incremental capacity as identified above. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals, as well as finalization of scope.

Eastern Access Projects

Since October 2011, we and Enbridge have announced multiple expansion projects that will provide increased access to refineries in the United States Upper Midwest and the Canadian provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. One of the projects involved the expansion of the Partnership s Line 5 light crude line between Superior, Wisconsin and Sarnia, Ontario by 50,000 Bpd. The Line 5 expansion was placed into service in May 2013. In May 2012, we and Enbridge announced further plans to expand access to Eastern markets. The projects to be pursued by the Partnership include: (1) expansion of the Spearhead North pipeline, or Line 62 expansion, between Flanagan, Illinois and the Terminal at Griffith, Indiana by adding horsepower to increase capacity from 130,000 Bpd to 235,000 Bpd; and (2) replacement of additional sections of the Partnership s Line 6B in Indiana and Michigan, referred to as the Line 6B Replacement project, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, as well as tanks at Flanagan, Stockbridge and Hartsdale, to increase capacity from 240,000 Bpd to 500,000 Bpd. Portions of the existing 30-inch diameter pipeline are being replaced with 36-inch diameter pipe. The Line 62 expansion was put into service in November 2013. The target in-service date for the remaining Line 6B Replacement project is split into two phases, with the segment between Griffith and Stockbridge expected to be completed in the first quarter of 2014 and the segment from Ortonville, Michigan to Sarnia, Ontario expected to be completed in the third quarter of 2014. These projects, including the previously discussed Line 5 and Line 62 expansion completions, will cost approximately $2.1 billion and will be undertaken on a cost-of-service basis with shared capital cost risk, such that the toll surcharge will absorb 50% of any cost overruns over $1.85 billion during the Competitive Toll Settlement, or CTS, term, which runs until July 2021.

As part of the Light Oil Market Access Program announced in December 2012, the Partnership will expand the Eastern Access Projects, which will include further expansion of the Line 6B component with increasing capacity from 500,000 Bpd to 570,000 Bpd and will involve the addition of new pumps, existing station modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge, at an expected cost of approximately $365 million. This further expansion of the Line 6B component is expected to begin service in early 2016.

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These projects collectively referred to as the Eastern Access Projects, will cost approximately $2.4 billion. From May 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Eastern Access Joint Funding agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we will have the option to increase our economic interest by up to 15 percentage points.

U.S. Mainline Expansions

In May 2012, we also announced further expansion of our mainline pipeline system, which included: (1) increasing capacity on the existing 36-inch diameter Alberta Clipper pipeline, or Line 67, between Neche, North Dakota into the Superior, Wisconsin Terminal from 450,000 Bpd to 570,000 Bpd; and (2) expanding of the existing 42-inch diameter Southern Access pipeline, or Line 61, between the Superior Terminal and the Flanagan Terminal near Pontiac, Illinois from 400,000 Bpd to 560,000 Bpd. These projects require only the addition of pumping horsepower and crude oil tanks at existing sites with no pipeline construction, at a cost of approximately $420 million. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at its currently planned operating capacity of 800,000 Bpd, the expansions will be undertaken on a full cost-of-service basis and are expected to be available for service in the third quarter of 2014 for the initial expansion to 570,000 Bpd and 2015 for the expansion to 800,000 Bpd. It is now anticipated that it will take longer to obtain regulatory approval than planned. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput.

As part of the Light Oil Market Access Program announced in December 2012, the capacity of our Lakehead System between Flanagan, Illinois, and Griffith, Indiana will be expanded by constructing a 76-mile, 36-inch diameter twin of the Spearhead North pipeline, or Line 62, with an initial capacity of 570,000 Bpd, at an estimated cost of $495 million. Additionally, the capacity of our Southern Access pipeline, or Line 61, will be expanded to its full 1,200,000 Bpd potential and additional tankage requirements at an estimated cost of approximately $1.25 billion. Subject to regulatory and other approvals, the expansions are expected to begin service in 2015, with additional tankage expected to be completed in 2016.

On January 4, 2013, we announced further expansion of our Alberta Clipper pipeline, or Line 67, which will add an additional 230,000 Bpd of capacity at an estimated cost of approximately $240 million. The expansion involves increased pumping horsepower, with no pipeline construction. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of the Line 67 pipeline at its currently planned operating capacity of 800,000 Bpd, the expansion is expected to be available for service in 2015.

These projects collectively referred to as the U.S. Mainline Expansions projects, will cost approximately $2.4 billion and will be undertaken on a cost-of-service basis. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the U.S. Mainline Expansions projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for 2016, the Partnership will have the option to increase its economic interest by up to 15 percentage points.

Canadian Eastern Access and U.S. Mainline Expansion Projects

The Eastern Access Projects and U.S. Mainline Expansions projects complement Enbridge s strategic initiative of expanding access to new markets in North America for growing production from western Canada and the Bakken Formation.

Since October 2011, Enbridge also announced several complementary Eastern Access and Mainline Expansion Projects. These projects include: (1) reversal of Enbridge s Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario; (2) construction of a 35-mile pipeline adjacent to Enbridge s Toledo Pipeline, originating at the Partnership s Line 6B in Michigan to serve refineries in Michigan and Ohio; (3) reversal of Enbridge s Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec; (4) an expansion of Enbridge s Line 9B to provide additional delivery capacity within Ontario and Quebec; (5) expansions to add horsepower on existing lines on the Enbridge Mainline system from western Canada to the U.S. border; and (6) modifications to existing terminal facilities on the Enbridge Mainline system, comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections in order to accommodate additional light oil volumes and enhance operational flexibility. The Line 9A reversal was completed in August 2013. The 35-mile pipeline adjacent to Enbridge s Toledo Pipeline was completed and placed into service in May 2013. Several of the outstanding projects remain subject to regulatory approval and have various targeted in-service dates through 2015. These projects will enable growing light crude production from the Bakken shale and from Alberta to meet refinery needs in Michigan, Ohio, Ontario and Quebec. These projects will also provide much needed transportation outlets for light crude, mitigating the current discounting of supplies in the basins, while also providing more favorable supply costs to refiners currently dependent on crudes priced off of the Atlantic basin.

Line 6B 75-mile Replacement Program

On May 12, 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments are being completed in components, with approximately 65 miles of segments placed in service since the first quarter of 2013. The two remaining 5-mile segments in Indiana are expected to be placed in service in components in the first quarter of 2014. The replacement program has been carried out in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. The total capital for this replacement program is now estimated to cost $390 million. These costs will be recovered through our Facilities Surcharge Mechanism, or FSM, which is part of the system-wide rates of the Lakehead system.

Berthold Rail

In December 2011, we announced that we were proceeding with the Berthold Rail Project, an interim solution to shipper needs in the Bakken region. The project expands pipeline capacity into the Berthold, North Dakota Terminal by 80,000 Bpd and included the construction of a three unit-train loading facility, crude oil tankage and other terminal facilities adjacent to existing facilities. During September 2012, the first phase of terminal facilities was completed, providing capacity of 10,000 Bpd to the Berthold Terminal. The final construction of the loading facility and the crude oil tankage (Phase II) were placed into service in March 2013. The estimated cost of the Berthold Rail Project was approximately $135 million.

Bakken Pipeline Expansion

In August 2010, we announced the Bakken Project, a joint crude oil pipeline expansion project with an affiliate of Enbridge in the Bakken and Three Forks formations located in North Dakota. The Bakken Project follows our existing rights-of-way in the United States and those of Enbridge Income Fund Holdings in Canada to terminate and deliver to the Enbridge Mainline system s terminal at Cromer, Manitoba, Canada. The United States portion of the Bakken Project expands the United States portion of the Portal Pipeline, which was reversed in 2011 in order to flow oil from Berthold to the United States border and on to Steelman, Saskatchewan, by constructing two new pumping stations in Kenaston and Lignite, North Dakota, and replacing an 11-mile segment of the existing 12-inch diameter pipeline that runs from these two locations. The project also expanded our existing terminal and station in Berthold, North Dakota. We commenced construction in July of 2011 and the Bakken Project was completed and placed into service in March 2013 providing capacity of 145,000 Bpd. This project, with the North Dakota mainline, results in a total takeaway capacity for this region of 355,000 Bpd. The United States portion of the Bakken Project had an estimated cost of approximately $300 million.

Bakken Access Program

In October 2011, we announced the Bakken Access Program, a series of projects which represents an upstream expansion that will further complement our Bakken Project, discussed above. This expansion program was placed into service in phases in mid-2013, substantially enhancing our gathering capabilities on the North Dakota system by 100,000 Bpd and increasing pipeline capacities, constructing additional storage tanks and adding truck access facilities at multiple locations in western North Dakota. The estimated cost of the Bakken Access Program remains at approximately $100 million.

Enbridge United States Gulf Coast Projects and Southern Access Extension

A key strength of the Partnership is our relationship with Enbridge. In 2011, Enbridge announced two major United States Gulf Coast market access pipeline projects, which, when completed, will pull more volume through the Partnership s pipeline, and may lead to further expansions of our Lakehead pipeline system. In addition, in 2012 Enbridge announced the Southern Access Extension, which will support the increasing supply of light oil from Canada and the Bakken into Pakota, Illinois.

<u>Flanagan South Pipeline</u>

Enbridge s Flanagan South Pipeline project will transport more volumes into Cushing, Oklahoma and twin its existing Spearhead pipeline, which starts at the hub in Flanagan, Illinois and delivers volumes into the Cushing hub. The 590-mile, 36-inch diameter pipeline will have an initial capacity of approximately 600,000 Bpd, and subject to regulatory and other approvals, the pipeline is expected to be in service by the third quarter of 2014. On August 23, 2013, the Sierra Club and National Wildlife Federation, the Plaintiff, filed a Complaint for Declaratory and Injunctive Relief, referred to as the Complaint, with the United States District Court for the District of Columbia, or the Court. The Complaint was filed against multiple federal agencies, or the Defendants, and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. On September 5, 2013, Enbridge obtained intervener status and joined the Defendants in filing a response in opposition to the motion for preliminary injunction. The Court hearing was held on September 27, 2013, and the Plaintiff s request for preliminary injunction was denied by the Court on November 13, 2013. A court hearing is scheduled for February 21, 2014 concerning the merits of the Complaint against the federal agencies.

<u>Seaway Crude Pipeline</u>

In 2011, Enbridge completed the acquisition of a 50% interest in the Seaway Crude Pipeline System, or Seaway. Seaway is a 670-mile pipeline that includes a 500-mile, 30-inch pipeline long-haul system that was reversed in 2012 to enable transportation of oil from Cushing, Oklahoma to Freeport, Texas, as well as a Texas

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City Terminal and Distribution System that serves refineries in the Houston and Texas City areas. Seaway also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and provided an initial capacity of 150,000 Bpd. Further pump station additions and modifications completed in January 2013 have increased the capacity to approximately 400,000 Bpd, depending upon the mix of light and heavy grades of crude oil. Actual throughput in 2013 was curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek facility to Enterprise Product Partners L.P. s, or Enterprise Product s, ECHO crude oil terminal, or ECHO Terminal, in Houston, Texas was completed in January 2014 and should eliminate these constraints.

In March 2012, based on additional capacity commitments from shippers, plans were announced to proceed with an expansion of the Seaway Pipeline through construction of a second line that is expected to more than double its capacity to 850,000 Bpd by mid-2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway Pipeline. Included in the scope of this second line is the lateral noted above from Houston, Texas to Enterprise Product s ECHO Terminal. Furthermore, a proposed 85-mile pipeline is expected to be built from Enterprise Product s ECHO Terminal to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region s heavy oil refining capabilities. The new pipeline will offer incremental capacity of 750,000 Bpd, and subject to regulatory approval, is expected to be available in mid-2014.

Southern Access Extension

In December 2012, Enbridge announced that it would undertake the Southern Access Extension project, which will consist of the construction of a 165-mile, 24-inch diameter crude oil pipeline from Flanagan to Patoka, Illinois, as well as additional tankage and two new pump stations. The initial capacity of the new line is expected to be approximately 300,000 Bpd. In addition, Enbridge announced two binding open seasons in 2013 to solicit commitments from shippers for capacity on the proposed pipeline. Prior to the binding open season that closed in January 2013, Enbridge had received sufficient capacity commitments from an anchor shipper to support the 24-inch pipeline. In June 2013, a second open season to solicit additional capacity commitments from shippers was announced and subsequently closed in September 2013. Enbridge received further capacity commitments through the second open season, which can be accommodated within the initial capacity planned for the pipeline. Subject to regulatory and other approvals, the project is expected to be placed into service in 2015.

Other Matters

Line 14 Corrective Action Orders

After the July 27, 2012 release of crude oil on Line 14, the PHMSA issued a Corrective Action Order on July 30, 2012 and an amended Corrective Action Order on August 1, 2012, which we refer to as the PHMSA Corrective Action Orders. The PHMSA Corrective Action Orders require us to take certain corrective actions, some of which have already been completed and some are still ongoing, as part of an overall plan for our Lakehead system.

A notable part of the PHMSA Corrective Action Orders was to hire an independent third party pipeline expert to review and assess our overall integrity program. The third party assessment will include organizational issues, response plans, training and systems. An independent third party pipeline expert was contracted during the third quarter of 2012 and their work is currently ongoing. The total cost of this plan is separate from the repair and remediation costs as discussed in Note 13. *Commitments and Contingencies Lakehead Line 14 Crude Oil Release* and is not expected to have a material impact on future results of operations.

Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013 we received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of twelve months. In December 2014, PHMSA will again consider the status of the pipeline in light of information they acquire throughout 2014.

Natural Gas

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

- Anadarko system: Approximately 3,100 miles of natural gas gathering and transportation pipelines, approximately 58 miles of NGL pipelines, nine active natural gas processing plants, three standby natural gas processing plants and one standby treating plant located in the Anadarko basin.

- East Texas system: Approximately 3,900 miles of natural gas gathering and transportation pipelines, approximately 108 miles of NGL pipelines, six active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, eight active natural gas treating plants, three standby natural gas treating plants and one fractionation facility located in the East Texas basin.

- North Texas system: Approximately 4,600 miles of natural gas gathering and transportation pipelines, approximately 60 miles of NGL pipelines, six active natural gas processing plants and one standby natural gas processing plant located in the Fort Worth basin.

- Texas Express NGL system: A 35% interest in an approximately 580-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. During startup operations, revenue recognition is delayed while the system is being filled with NGLs but operating costs are recognized. Additionally, the Texas Express NGL system operates using ship or pay contracts. These ship or pay contracts contain make-up rights provisions, which are earned when minimum volume commitments are not utilized during the contract period but are also subject to contractual expiry periods. Revenue associated with these make-up rights is deferred when more than a remote chance of future utilization exists. These factors in combination contributed to a $1.0 million equity loss for the year ended December 31, 2013, which we recognized in Other income (expense) on our consolidated statement of income.

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The following tables set forth the operating results of our Natural Gas segment and the approximate average daily volumes of natural gas throughput and NGLs produced on our systems for the years ended December 31, 2013, 2012, and 2011.

	December 31, 2013	2012	2011
	(in millions)		
Operating revenues	$ 3,867.2	$ 3,967.7	$ 5,692.5
Cost of natural gas	3,222.1	3,172.7	4,973.8
Environmental costs, net of recoveries			(0.4)
Operating and administrative	444.3	460.1	392.9
Depreciation and amortization	143.1	134.8	142.6
Operating expenses	3,809.5	3,767.6	5,508.9
Operating Income	$ 57.7	$ 200.1	$ 183.6
Operating Statistics (MMBtu/d):			
East Texas	1,153,000	1,266,000	1,378,000
Anadarko[(1)]	949,000	1,017,000	1,013,000
North Texas	317,000	330,000	337,000
Total	2,419,000	2,613,000	2,728,000
NGL Production (Bpd)	88,236	97,428	87,376

(1) Average daily volumes for the years ended December 31, 2013, 2012 and 2011 include 280,000 MMBtu/d, 255,000 MMBtu/d, and 251,000 MMBtu/d, respectively, of volumes associated with our Elk City system.

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 generate revenues and segment gross margin principally under the following types of arrangements:

Equity Investment in Joint Venture

Our natural gas and NGLs business includes our 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties, representing a 580-mile NGL intrastate transportation pipeline and a related NGL gathering system. We use the equity method of accounting for our 35% joint venture interest in the Texas Express NGL system as a result of our ability to significantly influence the operating activities, but insufficient ability to control these activities without the participation of a majority of the other members.

Fee-Based Arrangements

In a fee-based arrangement, we receive a fee per Mcf of natural gas processed or per gallon of NGLs produced. Under this arrangement, we have no direct commodity price exposure. We receive fee-based revenue for services, such as compression fees, gathering fees and treating fees that are recognized when volumes are received on our systems. Additionally, revenues 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 typically 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. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transportation services.

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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. We provide additional information in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk* and Note 15. *Derivative Financial Instruments and Hedging Activities* of our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* of this report about the derivative activities we use to mitigate our exposure to commodity price risk.

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 natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we can sell at market prices and retain 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. 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, 2013, we are exposed to fluctuations in commodity prices in the near term on approximately 35% to 40% of the 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. Many of the derivative financial instruments we use do not qualify for hedge accounting. As a result, we record the changes in fair value of the derivative instruments that do not qualify for hedge accounting in our operating results. This accounting treatment produces non-cash gains and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile.

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

The operating income of our Natural Gas business for the year ended December 31, 2013 decreased $142.4 million, as compared with the year ended December 31, 2012. The most significant area affected was Natural Gas gross margin, representing revenue less cost of natural gas, which decreased $149.9 million for the year ended December 31, 2013 as compared with the year ended December 31, 2012.

The gross margin for our Natural Gas segment was negatively affected by the reduction in 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 some NGLs at Conway hub prices and then have the ability to resell the NGLs at Mont Belvieu hub prices. For the year ended December 31, 2013, the prevailing price for NGLs increased approximately 6% per composite barrel at the Conway pricing hub, and decreased approximately 9% per composite barrel at the Mont Belvieu pricing hub, in each case as compared with the prevailing composite barrel prices for the year ended December 31, 2012. The gross margin of our Natural Gas 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 the changes in NGL prices between these pricing hubs.

A variable element of the operating results of our Natural Gas 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.

Reduced production volumes negatively affected gross margin by approximately $27.0 million for the year ended December 31, 2013. The average daily volumes of our major systems for the year ended December 31, 2013 decreased by approximately 194,000 MMBtu/d, or 7%, when compared to the year ended December 31, 2012. The average NGL production, for the year ended December 31, 2013 decreased by approximately 9,192 Bpd, or 9%, when compared to the year ended December 31, 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 December 31, 2013 as compared to December 31, 2012 also contributed to the reduced volumes. During 2013, two different sustained freezing events negatively impacted volumes 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 is expected to be back to full capacity in February 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 December 31, 2013, it was more profitable to operate most of the processing plants on our Anadarko system in ethane rejection mode, which results in lower NGL volumes, since ethane is sold as part of the natural gas stream.

Also contributing to the decrease in gross margin for the year ended December 31, 2013 were $7.2 million of additional revenues for gas plant allocation corrections recognized during the year ended December 31, 2012,

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with no similar corrections recognized for the year ended December 31, 2013. These allocation corrections related to measured volumes at one of our North Texas plants that were being improperly included as part of the NGL revenue allocation with third party producers.

Another factor in the decrease to gross margin for the year ended December 31, 2013 was a decrease of approximately $8.0 million due to changes in estimate to actual adjustments for the year ended December 31, 2013 as compared to the year ended December 31, 2012. For our Natural Gas segment, we estimate our current month revenue and cost of natural gas to permit the timely preparation of our consolidated financial statements. As a result, each month we record a true-up of the prior month s estimate to equal the prior month s actual data. Refer to Item 8. *Critical Accounting Policies and Estimates* for additional information regarding the estimation of our revenues and our cost of natural gas.

Operating income of our Natural Gas segment experienced non-cash, mark-to-market net losses of $4.5 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 natural gas business.

Also contributing to the decrease in 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 administrative costs of our Natural Gas segment decreased $15.8 million for the year ended December 31, 2013 when compared to the year ended December 31, 2012, primarily due to the following:

- Decreased current year costs of $7.5 million for the investigation related to accounting misstatements at our trucking and NGL marketing subsidiary recorded in 2012, with no similar costs recorded during the year ended December 31, 2013. See *Trucking and NGL Marketing Business Accounting Matters* for additional discussion;

- Decreased operational related costs of $6.8 million due to favorable spending for rents, maintenance, supplies and other outside services for the year ended December 31, 2013 when compared to the year ended December 31, 2012; and

- Decreased current year costs of $4.3 million for the prior year write down 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 Natural Gas segment increased $8.3 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.

Year ended December 31, 2012 compared with year ended December 31, 2011

The gross margin of our Natural Gas segment for the year ended December 31, 2012 increased by $76.3 million from the year ended December 31, 2011 due to higher NGL production partially offset by lower commodity prices and natural gas volumes, as well as other factors described below.

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For the year ended December 31, 2012, prices for natural gas and NGLs declined significantly from the year ended December 31, 2011. Average natural gas prices declined approximately 31% per MMBtu based upon the NYMEX Henry Hub pricing index, for the year ended December 31, 2012, when compared to the year ended December 31, 2011. NGLs declined approximately 30% and 28% per composite barrel, for the year ended December 31, 2012 as compared to the year ended December 31, 2011, based upon the Conway and Mont Belvieu pricing hubs, respectively.

Gross margin derived from keep-whole earnings for the year ended December 31, 2012 increased $49.2 million from the year ended December 31, 2011. The increase in keep-whole earnings was attributable to paying natural gas producers, during the prior year, for liquids we were unable to recover due to gas volumes increasing faster than our available capacity on our Anadarko system. For the year ended December 31, 2012, the capacity condition was relieved due to the completion of the Allison processing plant in November 2011 and additional third party NGL takeaway capacity.

Gross margin for the year ended December 31, 2012, when compared to the year ended December 31, 2011, increased approximately $33.0 million due to the correction of accounting misstatements and other errors during the year ended December 31, 2011. In early 2012, an internal and an independent investigation identified intentional accounting misstatements and other errors by on-site management at our wholly-owned trucking and NGL marketing subsidiary over a period of several years. Following further investigation and determination we recorded the cumulative aggregate amount of the misstatements and other errors at December 31, 2011 as a reduction to the operating income of our Natural Gas segment. For additional discussion see *Trucking and NGL Marketing Business Accounting Matters*. There were no such adjustments for accounting misstatements or other accounting errors during the year ended December 31, 2012.

Also, during 2011, our volumes were negatively impacted due to uncharacteristically cold weather and freezing precipitation in February that moved through Oklahoma and north Texas with temperatures dropping below freezing for extended periods. These conditions resulted in significant mechanical issues with our producers equipment and impacted their ability to flow natural gas. Producers shut in substantial volumes during this period, which reduced the average daily volumes on our systems by approximately 56,000 MMBtu/d. Additionally, mechanical problems on two of our plants required that they be taken out of service for extended periods during the first quarter of 2011 to correct these conditions. The adverse weather conditions and plant downtime had an approximate $13.0 million negative impact to the gross margin of our Natural Gas segment for the year ended December 31, 2011.

Gross margin for the year ended December 31, 2012, increased $13.0 million, when compared to the year ended December 31, 2011, due to fee-based contracts on our East Texas, Anadarko, and Oklahoma systems. The increase in fee-based operating income was due to several factors including: (1) lower customer wellhead operating pressures resulting in higher fees to transport their natural gas; (2) changes to our customer contracts resulting in higher fees; and (3) additional volumes from our Haynesville expansion.

Gross margin also increased $11.2 million, for the year ended December 31, 2012 when compared to the year ended December 31, 2011, related to higher NGL recoveries due to increased efficiencies on our Anadarko system from the completion of our Allison plant and higher NGL content in the processing gas stream.

Additionally, gross margin from our condensate marketing business for the year ended December 31, 2012 increased approximately $10.8 million, from the year ended December 31, 2011, due to higher realized margins from enhancements of facilities that were placed into service during 2012.

The gross margin of our Natural Gas segment experienced non-cash, mark-to-market net losses of $11.5 million from December 31, 2011 to December 31, 2012 mostly due to the maturity of certain hedging agreements. These maturities were partially offset by changes in the average forward prices of natural gas, NGLs and condensate. The average forward and daily prices for natural gas and NGLs decreased for the year ended December 31, 2012, compared to the year ended December 31, 2011.

Operating and administrative costs of our Natural Gas segment were $67.2 million higher for the year ended December 31, 2012 compared to the year ended December 31, 2011, primarily due to the following:

- Increased workforce related costs and other allocated expenses of $26.0 million primarily due to programs and initiatives focused on renewing our focus on safety, operations and systems integrity in addition to the completion of the Allison plant and other assets being placed into service during late 2011;

- Increased supporting costs of $10.6 million related to maintenance, supplies and other outside services also associated with additional assets being placed into service during late 2011;

- Increased costs of $7.5 million for the investigation of accounting misstatements at our trucking and NGL marketing subsidiary with no similar costs during the same period in 2011. See *Trucking and NGL Marketing Business Accounting Matters* for additional discussion;

- Increased pipeline integrity costs of $7.2 million as part of the operational risk management plan to ensure our systems are safe and to maintain our existing pipelines; and

- Increased costs of $4.3 million related to 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.

Depreciation and amortization expense for our Natural Gas segment decreased $7.8 million, for the year ended December 31, 2012 compared with the year ended December 31, 2011, primarily due to a revision in depreciation rates for the Anadarko, North Texas and East Texas systems which became effective on July 1, 2011. The revision resulted in a decrease of approximately $17.0 million in depreciation expense for the year ended December 31, 2012, when compared to the year ended December 31, 2011. This decrease was offset with an increase in depreciation expense associated with additional assets that were put in service during late 2011.

Trucking and NGL Marketing Business Accounting Matters

At our wholly-owned trucking and NGL marketing subsidiary, we identified accounting misstatements and other errors in early 2012 associated with the financial statement recognition of NGL product purchases and sales within our Natural Gas segment over a period of several years. We refer to the improper recognition of product purchases as the accounting misstatements and the improper recognition of product sales as accounting errors in the discussions which follow. The accounting misstatements were facilitated by conduct of the local management responsible for operating the subsidiary, whereby entries were made to modify the amounts reported for cost of goods sold included in Cost of natural gas, and Accrued purchases for the purposes of creating the appearance that the subsidiary had achieved its budget. During the performance of our review of the accounting misstatements, we identified other unrelated accounting errors associated with the recognition of sales resulting in the misstatement of Operating revenue, Accrued receivables and Inventory, during each accounting period. The accounting misstatements, and accounting errors, which include overstatements, understatements and other errors, occurred over a period from at least 2005 through 2011. Our net cash provided by operating activities was not affected by the accounting misstatements during these periods.

For the year ended December 31, 2010, the cumulative aggregate amount of the accounting misstatements and accounting errors was approximately $33.0 million. During 2011, local management of the trucking and NGL marketing subsidiary recorded entries totaling approximately $15.0 million as increases to cost of goods sold included in Cost of natural gas and decreases to Operating revenue that reduced the cumulative aggregate amount to $18.0 million at December 31, 2011. Following further investigation and determination that the previously unrecorded amounts were not material to the current or any prior period financial statements, we recorded the cumulative aggregate amount of $18.0 million, representing the accounting misstatements and accounting errors, at December 31, 2011 as a reduction to the Operating income of our Natural Gas segment to correct these accounting misstatements and accounting errors. As a result, the Operating income of our

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Natural Gas segment for the year ended December 31, 2011 was $33.0 million less than what we would have reported had the accounting misstatements and accounting errors been recognized in the year ended December 31, 2010. The $33.0 million is comprised of the $15.0 million of adjustments recorded by local management of the trucking and NGL marketing subsidiary during 2011 and the $18.0 million correction we recorded at December 31, 2011.

Future Prospects for Natural Gas

We intend to expand our natural gas gathering and processing services through 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.

The table below summarizes the Partnership s commercially secured projects for the Natural Gas segment, which we have recently placed into service or expect to place into service in future periods. Following MEP s initial public offering in November 2013, the below projects are now funded by the Partnership and MEP based on their proportionate ownership percentages in Midcoast Operating:

Project	Estimated Capital Costs (in millions)	In-service Date	Funding
Ajax Cryogenic Processing Plant	$ 230	Q3 2013	EEP
Texas Express NGL system	$ 400	Q4 2013	Joint[2]
Beckville Cryogenic Processing Plant	$ 145	Early 2015	Joint[1]

(1) Following the Offering in November 2013, Beckville is now funded by EEP and MEP based on their proportionate ownership percentages in Midcoast Operating, which is currently 61% and 39%, respectively.

(2) We own a 35% joint venture interest in the Texas Express NGL system. Estimated capital costs represent 35% of the total projected costs associated with constructing both the mainline and the gathering system.

Ajax Cryogenic Processing Plant

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, current market prices for NGLs and crude oil and the application of horizontal drilling and fracturing technology to the formation. In order to accommodate the expected natural gas production growth from the Granite Wash play, we began commissioning the operations of a cryogenic processing plant and related facilities 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 provide necessary capacity to accommodate the anticipated volume growth within our Anadarko system. The total cost of constructing the Ajax processing plant and related facilities was approximately $230 million. The Ajax processing plant increases the total processing capacity of our Anadarko system by approximately 150 million cubic feet per day, or MMcf/d, to approximately 1,150 MMcf/d and also increases the system s condensate stabilization capacity by approximately 2,000 Bpd. The Ajax processing plant is capable of producing approximately 15,000 barrels per day, or Bpd, of NGLs now that the Texas Express NGL pipeline, which we refer to as the mainline, was completed and put into operation during the fourth quarter of 2013 as discussed below.

Texas Express NGL System

On October 31, 2013, we, 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

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Express NGL system, which consists of two separate joint ventures with third parties to design and construct a new 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 580-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. The new NGL gathering system initially consists of approximately 116-miles of gathering lines that connect the mainline to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma and to Barnett Shale processing plants in North Texas. The gathering system is currently expected to include 270-miles of gathering lines by 2019. Volumes from the Rockies, Permian Basin and Mid-Continent regions will be delivered to the Texas Express NGL system utilizing Enterprise s existing Mid-America Pipeline assets between the Conway hub and Enterprise s Hobbs NGL fractionation facility in Gaines County, Texas. In addition, volumes from and to the Denver-Julesburg Basin in Weld County, Colorado are able to access the Texas Express NGL system through the connecting Front Range Pipeline which is being constructed by Enterprise, DCP Midstream and Anadarko.

We expect that the Texas Express NGL system will serve as a link between growing supply sources of NGLs in the Anadarko and Permian basins and the Mid-Continent and Rockies regions of the United States and the primary demand markets on the U.S. Gulf Coast. We expect our total contributions to be approximately $400 million for the construction of the Texas Express NGL system.

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. Production from this play 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. In the third quarter of 2013, we initiated construction activities at our Beckville processing plant and the related facilities on our East Texas system. We estimate the cost of constructing the plant to be approximately $145 million and expect it to commence service in early 2015.

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Marketing

The following table sets forth the operating results of our Marketing segment assets for the periods presented:

	2013	December 31, 2012 (in millions)	2011
Operating revenues	$ 1,730.0	$ 1,392.6	$ 2,131.9
Cost of natural gas	1,726.8	1,397.4	2,126.3
Operating and administrative	5.5	6.6	6.3
Depreciation and amortization			0.1
Operating expenses	1,732.3	1,404.0	2,132.7
Operating income (loss)	$ (2.3)	$ (11.4)	$ (0.8)

Our Marketing business derives a majority of its operating income from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers utilizing the natural gas. A majority of the natural gas we purchase is produced in Texas markets where we have expanded access to several interstate natural gas pipelines over the past several years, which we can use to transport natural gas to primary markets where it can be sold to major natural gas customers.

Our Marketing business is exposed to commodity price fluctuations because the natural gas purchased by our Marketing business is generally priced using an index that is different from the pricing index at which the gas is sold. This price exposure arises from the relative difference in natural gas prices between the contracted index at which the natural gas is purchased and the index under which it is sold, otherwise known as the basis spread. The spread can vary significantly due to local supply and demand factors. Wherever possible, this pricing exposure is economically hedged using derivative financial instruments. However, the structure of these economic hedges often precludes our use of hedge accounting under authoritative accounting guidance, which can create volatility in the operating results of our Marketing segment.

In addition to the market access provided by our company-owned intrastate natural gas pipelines, our Marketing business also contracts for firm transportation capacity on third-party interstate and intrastate pipelines to allow access to additional markets. To mitigate the demand charges associated with these transportation agreements, we look for market conditions that allow us to lock in the price differential between the pipeline receipt point and pipeline delivery point. This allows our Marketing business to lock in a fixed sales margin inclusive of pipeline demand charges. We accomplish this by transacting basis swaps between the index where the natural gas is purchased and the index where the natural gas is sold. By transacting a basis swap between those two indices, we can effectively lock in a margin on the combined natural gas purchase and the natural gas sale, mitigating our exposure to cash flow volatility that could arise in markets where transporting the natural gas becomes uneconomical. However, the structure of these transactions precludes our use of hedge accounting under authoritative accounting guidance, which can create volatility in the operating results of our Marketing segment.

In addition to natural gas transport capacity and the associated basis swaps, we contract for storage to assist with balancing natural gas supply and end use market sales. In order to mitigate the absolute price differential between the cost of injected natural gas and withdrawals of natural gas, as well as storage fees, the injection and withdrawal price differential is hedged by buying fixed price swaps for the forecasted injection periods and selling fixed price swaps for the forecasted withdrawal periods. When the injection and withdrawal spread increases or decreases in value as a result of market price movements, we can earn additional profit through the optimization of those hedges in both the forward and daily markets. Although all of these hedge strategies are sound economic hedging techniques, these types of financial transactions do not qualify for hedge accounting under authoritative accounting guidance. As such, the non-qualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value, although non-cash, will impact our operating results.

Natural gas purchased and sold by our Marketing segment 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. At their request, we will enter into long-term, fixed-price purchase or sales contracts with our customers and generally will enter into offsetting hedged positions under the same or similar terms.

Our Marketing business pays third-party storage facilities and pipelines for the right to store and transport natural gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities.

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

The operating results of our Marketing segment for the year ended December 31, 2013 increased by $9.1 million when compared to the year ended December 31, 2012.

The increase in operating results of our Marketing business, was primarily due to higher natural gas prices during the year ended December 31, 2013, when compared to the year ended December 31, 2012. This improved pricing environment led to additional opportunities to benefit from improved price differentials between market centers which enable us to increase our margins in certain circumstances. As a result, our marketing operations generated a $6.5 million gain for the year ended December 31, 2013, as compared to a $2.3 million gain for the year ended December 31, 2012.

Also contributing to the increase in operating results of our Marketing segment, for the year ended December 31, 2013, was the expiration of certain transportation fees for natural gas being transported on a third party pipeline. These transportation 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.

Operating results for the current year were positively affected by only $0.4 million of non-cash charges to inventory for the year ended December 31, 2013, compared to $2.0 million 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.

Included in the operating results of our Marketing segment for the year ended December 31, 2013 were non-cash, mark-to-market net losses of $2.8 million as compared with $3.1 million of non-cash, mark-to-market net losses for the year ended December 31, 2012 associated with derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. The decrease in non-cash, mark-to-market net losses for the year ended December 31, 2013, as compared to the year ended December 31, 2012, was primarily attributed to the realization of financial instruments used to hedge our transportation positions. The net losses associated with these derivative instruments resulted from the widening difference between the forward natural gas purchase and sales prices between market centers, which negatively impacted the values of the derivative financial instruments we use to hedge our transportation positions.

Year ended December 31, 2012 compared with year ended December 31, 2011

The operating results of our Marketing segment for the year ended December 31, 2012 decreased by $10.6 million when compared to the year ended December 31, 2011 primarily due to the continued erosion of natural gas prices and associated differentials.

Natural gas prices for the year ended December 31, 2012 were lower and relatively stable as compared to the year ended December 31, 2011. This price environment led to limited opportunities to benefit from significant price differentials between market centers, which negatively impacted the Marketing segment operating results by $7.3 million for the year ended December 31, 2012, as compared to the year ended December 31, 2011.

Included in the operating results of our Marketing segment for the year ended December 31, 2012 were non-cash, mark-to-market net losses of $3.1 million as compared with $0.7 million of non-cash, mark-to-market net gains for the year ended December 31, 2011 associated with derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. This increase in non-cash, mark-to-market net losses for the year ended December 31, 2012, as compared to the year ended December 31, 2011, was primarily attributed to the realization of financial instruments used to hedge our storage and transportation positions. The net losses associated with our storage derivative instruments resulted from the widening difference between the natural gas injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas was sold from storage.

Corporate Activities

Our corporate activities consist of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	2013	December 31, 2012 (in millions)	2011
Operating Results:			
General and administrative expenses	$ 7.6	$ 2.3	$ 2.2
Operating loss	(7.6)	(2.3)	(2.2)
Interest expense	320.4	345.0	320.6
Allowance for equity used during construction	43.1	11.2	
Other income (expense)	16.0	(1.2)	6.5
Income tax expense	18.7	8.1	5.5
Net loss	(287.6)	(345.4)	(321.8)
Net income attributable to Noncontrolling interest	88.3	57.0	53.2
Series 1 preferred unit distributions	58.2		
Accretion of discount on Series 1 preferred units	9.2		
Net loss attributable to general and limited partners	$ (443.3)	$ (402.4)	$ (375.0)

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

The increase in our net loss in 2013 was mostly attributed to the issuance of Series 1 Preferred Units by the Partnership to its General Partner in May of 2013. The Partnership attributed approximately $58.2 million of earnings to the preferred unitholders in 2013 as compared to the same period in 2012.

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Offsetting the increase in Series 1 preferred unit distributions was a decrease in interest expense from $320.4 million for the year ended December 31, 2013, compared with $345.0 million for the corresponding period in 2012. This decrease in interest expense is primarily due to an increase of $15.4 million in capitalized interest related to our capital projects and a decreased weighted average outstanding debt balance due to a decrease in the commercial paper balance and repayment of $200.0 million of senior unsecured notes.

Income tax expense increased $10.6 million for the year ended 2013 compared to the same period in 2012, primarily due to a $12.4 million of income tax expense recognized for the three month period ended June 30, 2013 related to a new law passed in the State of Texas. See Note 11. *Income Taxes* for further discussion regarding this new tax laws. Our interest cost for the years ended December 31, 2013 and 2012 is detailed below:

	December 31, 2013	December 31, 2012
	(in millions)	
Interest expense	$ 320.4	$ 345.0
Interest capitalized	51.7	36.3
Interest incurred	$ 372.1	$ 381.3
Interest paid	$ 342.3	$ 352.1
Weighted average interest rate	*6.2%*	*6.4%*

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 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 $18.7 million, for the year ended December 31, 2013, is computed by applying a 0.5% Texas state income tax rate to modified gross margin. For 2012, we had an income tax expense of $8.1 million, which we computed by applying a 0.5% Texas state income tax rate to modified gross margin.

Year ended December 31, 2012 compared with year ended December 31, 2011

The increase in our net loss in 2012 was mostly attributable to the increase in interest expense as compared to the same period in 2011. Interest expense was $345.0 million for the year ended December 31, 2012 compared with $320.6 million for the corresponding period in 2011. This increase in interest expense is primarily the result of a higher weighted average outstanding debt balance during the year ended December 31, 2012 as compared with the same period in 2011. The increased weighted average outstanding debt balance was primarily a result of the issuance and sale in September 2011 of $600 million of our 4.20% senior unsecured notes due 2021 and an additional $150 million of our 5.50% senior unsecured notes due 2040. These additions were partially offset by a lower commercial paper balance, the maturity of $100 million of our 7.9% senior unsecured notes in November 2012 and the maturity of our First Mortgage Notes in December 2011.

We are exposed to interest rate risk associated with changes in interest rates on our variable rate debt. The interest rates on our variable rate debt are determined at the time of each borrowing or interest rate reset based upon a posted London Interbank Offered Rate, or LIBOR, for the period of borrowing or interest rate reset, plus applicable margin. In order to mitigate the negative effect that increasing interest rates can have on our cash flows, we have purchased interest rate swaps with a total notional value of $4.9 billion as of December 31, 2012. The changes in fair value of the interest rate swaps that do not qualify for hedge accounting are recorded as corresponding increases or decreases in Interest expense on our consolidated statements of income. For the year ended December 31, 2012 interest expense increased due to recognition of unrealized losses for hedge ineffectiveness of approximately $20.8 million associated with interest rate hedges that were originally set to mature in December 2012. However, in December 2012, these hedges were amended to extend the maturity date to December 2013 to better reflect the expected timing of future debt issuances.

Offsetting the increase in interest expense is the $22.7 million increase in interest capitalized to our capital projects for year ended December 31, 2012 as compared to the same period in 2011. This is due to higher amounts spent on our capital projects in 2012 that have not yet been placed into service. Our interest cost for the years ended December 31, 2012 and 2011 is detailed below:

	December 31, 2012	December 31, 2011
	(in millions)	
Interest expense	$ 345.0	$ 320.6
Interest capitalized	36.3	13.6
Interest incurred	$ 381.3	$ 334.2
Interest paid	$ 352.1	$ 314.3
Weighted average interest rate	*6.4%*	*6.4%*

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 tax structure that exists in Texas and Michigan impose taxes that are based upon many, but not all, items included in net income. Our income tax expense of $8.1 million, for the year ended December 31, 2012 is computed by applying a 0.5% Texas state income tax rate to modified gross margin. For 2011, we had an income tax expense of $5.5 million, which we computed by applying a 0.5% Texas state income tax rate to modified gross margin, and a 0.2% Michigan state income tax rate to net income and modified gross receipts. The $5.5 million represents $6.6 million of expense related to Texas and $1.1 million of benefit related to Michigan. The Michigan benefit is related to the Michigan Business Tax being repealed in 2011. Due to this change in Michigan tax legislation, we no longer are required to pay Michigan income taxes beginning in 2012 as discussed in Note 16. *Income Taxes*.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge including our General Partner. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In connection with the joint funding arrangement, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $52.6 million, $53.9 million and $53.2 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the years ended December 31, 2013, 2012 and 2011, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in Net income attributable to noncontrolling interest on our consolidated statements of income.

Joint Funding Arrangement for Eastern Access Projects

In May 2012, we amended and restated partnership agreement of the OLP to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and our affiliates entered into an agreement with our

General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $609.2 million and $347.9 million to the OLP for the year ended December 31, 2013 and 2012, respectively to fund its equity portion of the construction costs associated with the Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $32.1 million to our General Partner for its 60% ownership of the EA interest for the year ended December 31, 2013. We allocated earnings derived from the Eastern Access Projects in the amount of $3.4 million to our General Partner for the year ended 2012. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Joint Funding Arrangement for the U.S. Mainline Expansion

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. We received $12.0 million from our General Partner in consideration for our economic interest. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points.

Our General Partner has made equity contributions totaling $159.9 million and $3.0 million to the OLP for the year ended December 31, 2013 and year ended 2012, respectively to fund its equity portion of the construction costs associated with the U.S. Mainline Expansion Projects.

We allocated earnings from the Mainline Expansion Projects in the amount of $0.3 million to our General Partner for its ownership of the ME interest for the year ended December 31, 2013. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

Our primary source of short-term liquidity is provided by our $1.5 billion commercial paper program, which is supported by our $1.975 billion credit agreement with Bank of America, as administrative agent, and the lenders party thereto, which we refer to as the Credit Facility, and our $1.2 billion credit agreement with JPMorgan Chase Bank as administrative agent, and the lenders party thereto, which we refer to as the 364-Day Credit Facility. We refer to the 364-Day Credit Facility and the Credit Facility as our Credit Facilities. We have a $1.5 billion commercial paper program that is supported by our Credit Facilities, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

As set forth in the following table, we had approximately $2.6 billion of liquidity available to us at December 31, 2013 to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental remediation costs resulting from the crude oil releases on Lines 6A and 6B.

	(in millions)
Cash and cash equivalents	$ 164.8
Total credit available under Credit Facilities	3,175.0
Less: Amounts outstanding under Credit Facilities	335.0
Principal amount of commercial paper issuances	300.0
Letters of credit outstanding	76.7
Total	$ 2,628.1

General

Our primary operating cash requirements consist of normal operating expenses, core maintenance expenditures, distributions to our partners and payments associated with our risk management activities. We expect to fund our current and future short-term cash requirements for these items from our operating cash flows supplemented as necessary by issuances of commercial paper and borrowings on our Credit Facilities. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facilities.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses through organic growth and targeted acquisitions. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our Credit Facilities. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all. In addition, we intend to sell additional interests in Midcoast Operating entity to MEP to raise capital over the course of the next several years. Although this is our intent, there is no assurance that any transactions, will occur as they are subject to, among other things, obtaining agreement from MEP and its Board of Directors around the commercial terms of such a sale. When we have attractive growth opportunities in excess of our own capital raising capabilities, the General Partner has provided supplementary funding, or participated directly in projects, to enable us to undertake such opportunities. If in the future we have attractive growth opportunities that exceed capital raising capabilities, we could seek similar arrangements from the General Partner, but there can be no assurance that this funding can be obtained.

As of December 31, 2013, we had a working capital deficit of approximately $1,316.6 million and approximately $2.6 billion of liquidity to meet our ongoing operational, investing and financing needs as of December 31, 2013 as shown above, as well as the funding requirements associated with the environmental costs resulting from the crude oil releases on Lines 6A and 6B.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these activities. We have issued a balanced combination of debt and equity securities to fund our expansion projects and acquisitions. Our internal growth projects and targeted acquisitions will require additional permanent capital and require us to bear the cost of constructing and acquiring assets before we begin to realize a return on them. If market conditions change and capital markets again become constrained, our ability and willingness to complete future debt and equity offerings may be limited. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Series 1 Preferred Units, representing limited partner interests in the Partnership, for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset every five years. However, these quarterly cash distributions, during the first full eight quarters ending June 30, 2015, will accrue and accumulate, which we refer to as the Payment Deferral. Thus the Partnership will accrue, but not pay these amounts until the earlier of the fifth anniversary of the issuance of such Preferred Units or the redemption of such Preferred Units by the Partnership. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) the Partnership uses the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions, including the Payment Deferral.

The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders and General Partner s capital and a decrease in Preferred Unitholders capital to reflect the fair value of the Preferred Units at issuance on the Partnership s consolidated statement of partners capital for the twelve month period ended December 31, 2013. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013 through the first conversion date, which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders capital. The impact of the beneficial conversion feature is also included in earnings per unit for the year ended December 31, 2013.

Proceeds from the Preferred Unit issuance were used by the Partnership to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

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Issuance of Class A Common Units

The following table presents the net proceeds from our Class A common unit issuances for the years ended December 31, 2012 and 2011. There were no similar issuances for the year ended December 31, 2013.

Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)			
2012					
September[(3)]	16,100,000	$ 28.64	$ 446.8	$ 9.4	$ 456.2
2011					
December[(4)]	9,775,000	$ 30.85	$ 292.0	$ 6.1	$ 298.1
September[(4)]	8,000,000	$ 28.20	218.3	4.6	222.9
July[(4)]	8,050,000	$ 30.00	233.7	4.9	238.6
2011 Totals	25,825,000		$ 744.0	$ 15.6	$ 759.6

(1) Net of underwriters fees and discounts, commissions and issuance expenses if any.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

(3) The proceeds from the September 2012 equity issuance were used to fund a portion of our capital expansion projects and for general partnership purposes.

(4) The proceeds from the December 2011 and September 2011 offerings were used to fund a portion of our capital expansion projects, while the proceeds from the July 2011 offering were used to repay a portion of our outstanding commercial paper and fund a portion of our capital expansion projects.

Equity Distribution Agreement

In June 2010, we entered into the Equity Distribution Agreement, or EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $150.0 million. The EDA allowed us to issue and sell our Class A common units at prices we deemed appropriate for our Class A common units. Under the EDA, we sold 2,118,025 Class A common units, representing 4,236,050 units after giving effect to a two-for-one split of our Class A common units that became effective on April 21, 2011, for aggregate gross proceeds of $124.8 million, of which $64.5 million are gross proceeds received in 2011. No further sales were made under that agreement. On May 27, 2011, we de-registered the remaining aggregate $25.2 million of Class A common units that were registered for sale under the initial EDA and remained unsold as of that date.

On May 27, 2011, the Partnership entered into the Amended and Restated Equity Distribution Agreement, or Amended EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $500.0 million from the execution date of the agreement through May 20, 2014. The units issued under the Amended EDA are in addition to the units offered and sold under the EDA. The issuance and sale of our Class A common units, pursuant to the Amended EDA, may be conducted on any day that is a trading day for the New York Stock Exchange, or NYSE.

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The following table presents the net proceeds from our Class A common unit issuances, pursuant to the initial EDA and the Amended EDA, during the year ended December 31, 2011. There were no similar issuances for the years ended December 31, 2013 or 2012:

Issuance Date	Number of Class A common units Issued	Average Offering Price per Class A common unit	Net Proceeds to the Partnership (1)	General Partner Contribution(2)	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)			
2011					
January 1 to March 31(3)	1,773,448	$ 32.26	$ 55.9	$ 1.2	$ 57.1
April 1 to May 26(3)	225,200	$ 32.16	7.0	0.1	7.1
May 27 to June 30(4)	333,794	$ 30.30	9.9	0.2	10.1
July 1 to September 30(4)	751,766	$ 28.38	20.8	0.4	21.2
2011 Totals	3,084,208		$ 93.6	$ 1.9	$ 95.5

(1) Net of commissions and issuance costs of $2.2 million.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

(3) Units and unit price adjusted for the April 2011 stock split.

(4) Units issued under the Amended EDA.

Midcoast Energy Partner, L.P.

On November 13, 2013, MEP, a subsidiary of EEP, completed its initial public offering (the Offering) of 18,500,000 Class A common units representing limited partner interests and subsequently issued an additional 2,775,000 Class A common units pursuant to the underwriter s over allotment option. MEP received proceeds (net of underwriting discounts, structuring fees and offering expenses) from the Offering of approximately $354.9 million. MEP 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. We intend to sell additional interests in our natural gas assets, held through Midcoast Operating, to MEP and use the proceeds from any such sale as a source of funding for EEP. Currently MEP has a 39% interest in Midcoast Operating.

Investments

In March and September 2013, Enbridge Management completed public offerings of 10,350,000 and 8,424,686 Listed Shares, respectively, representing limited liability company interests with limited voting rights, at a price to the underwriters of $26.44 and $28.02 per Listed Share, respectively. Enbridge Management received net proceeds of $272.9 million and $235.6 million for the March and September 2013 issuances, respectively, which we subsequently invested in an equal number of the Partnership s i-units. We used the proceeds from our sale of i-units to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

In November 2011, Enbridge Management completed a private offering of 860,684 listed shares, representing limited liability company interests in Enbridge Management with limited voting rights, at a price of $29.86 per listed share. Enbridge Management received net proceeds of $25.5 million which were subsequently invested in an equal number of our i-units. We used the proceeds to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our Credit Facilities. We have a $1.5 billion commercial paper program that is supported by our Credit Facilities, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our Credit Facilities.

Credit Facilities

In September 2011, we entered into the Credit Facility. The agreement is a committed senior unsecured revolving credit facility with a letter of credit subfacility and a swing line subfacility. The Credit Facility originally permitted aggregate borrowing of up to, at any one time outstanding, $2.0 billion. On October 28, 2013, we amended our Credit Facility to extend the maturity date from September 26, 2017 to September 26, 2018 and to reduce the aggregate permitted borrowings under the Credit Facility to up to, at any one time outstanding, $1.975 billion.

On July 6, 2012, we entered into the 364-Day Credit Facility. The agreement is a committed senior unsecured revolving credit facility pursuant to which the lenders have committed to lend us up to the aggregate commitment amount: (1) on a revolving basis for a 364-day period, extendible annually at the lenders discretion; and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods. The original agreement provided for aggregate borrowings up to $675 million at any one time outstanding. On February 8, 2013, we amended the 364-Day Facility to reflect an increase in the lending commitments to $1.1 billion.

On July 3, 2013, we amended our 364-Day Credit Facility, to extend the revolving credit termination date to July 4, 2014 and to increase aggregate commitments under the facility by $50.0 million. Furthermore, on July 24, 2013, we further amended the 364-Day Credit Facility, by adding a new lender and increasing our aggregate commitments under the facility by another $50.0 million. After these amendments, our 364-day Credit Facility now provides aggregate lending commitments of $1.2 billion.

On October 28, 2013, we further amended our Credit Facilities to modify, certain terms and conditions to accommodate the proposed initial public offering of Class A common units representing limited partner interests in MEP and the transactions contemplated thereby. The amendments were effective November 13, 2013.

Our Credit Facilities provide an aggregate amount of $3.175 billion of bank credit, as of December 31, 2013, which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at December 31, 2013, we could borrow $2.5 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$ 3,175.0
Less: Amounts outstanding under Credit Facilities	335.0
Principal amount of commercial paper outstanding	300.0
Letters of credit outstanding	76.7
Total amount we could borrow at December 31, 2013	$ 2,463.3

Individual London Interbank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the year ended December 31, 2013, we did not have any LIBOR rate borrowings or base rate borrowings.

Our Credit Facilities previously were amended to exclude up to $650 million of the costs associated with the remediation of the area affected by the crude oil releases on Lines 6A and 6B from the Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, component of the consolidated leverage ratio covenant in each of our Credit Facilities. On December 23, 2013, we amended the quarterly covenant compliance testing for each of the Credit Facilities. The amendment excludes from the definition of consolidated net income component of the consolidated leverage ratio covenant accrued but unpaid costs, expenses, fines, and penalties occurring after September 30, 2013 related to the remediation of the area affected by the crude oil releases on Lines 6A and 6B.

Our ability to comply with that covenant in the future will depend on our ability to generate sufficient internal cash flow, issue additional equity or reduce existing debt, each of which will be subject to prevailing economic conditions and other factors, including factors beyond our control. A failure to comply with that covenant could result in an event of default under the Credit Facilities, which would prohibit us from declaring or making distributions to our unitholders and would permit acceleration of, and termination of our access to, our indebtedness under the Credit Facilities, and may cause acceleration of our outstanding senior notes. Although we expect to be able to comply with this covenant under each of our Credit Facilities, there can be no assurance that in the future we will be able to do so or that our lenders will be willing to waive such non-compliance or further amend such covenants. As of December 31, 2013, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

On February 3, 2014, EEP entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank s sole discretion, we view this arrangement as liquidity enhancement as it allows EEP to potentially reduce its reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support its hedging activities.

Commercial Paper

At December 31, 2013, we had $300.0 million of commercial paper outstanding at a weighted average interest rate of 0.37%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $859.9 million during the year ended December 31, 2013, which include gross borrowings of $12,948.4 million and gross repayments of $13,808.3 million. Our policy is that the commercial paper we can issue is limited by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion.

Senior Notes

All of our senior notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries. The borrowings under our senior notes are non-recourse to our General Partner and Enbridge Management. All of our senior notes either pay or accrue interest semi-annually and have varying maturities and terms.

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Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. We issued the Junior Notes in September 2007 for proceeds of approximately $393.0 million net of underwriting discounts, commissions and offering expenses. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, payable semi-annually in arrears on April 1 and October 1 of each year until October 1, 2017. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017 and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047 or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part, prior to October 1, 2017, for a make-whole redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017 in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

Joint Funding Arrangements

In order to obtain the required capital to expand our various pipeline systems, we have determined that the required funding would challenge the Partnership s ability to efficiently raise capital. Accordingly, we have explored numerous options and determined that several joint funding arrangements would provide the best source of available capital to fund the expansion projects.

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010.

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with the construction of our portion of the Alberta Clipper Pipeline we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At December 31, 2013, we had approximately $318.0 million outstanding under the A1 Term Note.

Our General Partner made no equity contributions to the OLP during the year ended December 31, 2013 and 2012, respectively to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline. The OLP paid a distribution of $53.6 million and $59.9 million to our General Partner and its affiliate during the years ended December 31, 2013 and 2012 for their noncontrolling interest in the Series AC, representing limited partner ownership interests of the OLP that are specifically related to the assets, liabilities and operations of the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $52.6 million and $53.9 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the years ended December 31, 2013 and 2012, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in Net income attributable to noncontrolling interest on our consolidated statements of income.

Joint Funding Arrangement for Eastern Access Projects

In May 2012, the OLP amended and restated its limited partnership agreement to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% of all assets, liabilities and operations related to the Eastern Access Projects. On June 26, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $609.2 million and $347.9 million to the OLP during the year ended December 31, 2013 and 2012, respectively to fund its equity portion of the construction costs associated with the Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $32.1 million to our General Partner for its 60% ownership of the EA interest for the year ended December 31, 2013. We allocated earnings derived from the Eastern Access Projects in the amount of $3.4 million to our General Partner for the year ended 2012. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Joint Funding Arrangement for Mainline Expansion Projects

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and certain of our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the project from 40% to 25%. Within one year of the last project in-service date, scheduled for early 2016, the Partnership will also have the option to increase its economic interest held at that time by up to 15 percentage points.

Our General Partner has made equity contributions totaling $159.9 million and $3.0 million to the OLP during the year ended December 31, 2013 and 2012, respectively, to fund its equity portion of the construction costs associated with the U.S. Mainline Expansion Projects.

We allocated earnings from the Mainline Expansion Projects in the amount of $4.3 million to our General Partner for its ownership of the ME interest for the year ended December 31, 2013. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Midcoast Energy Partners, L.P.

On November 13, 2013, as part of the MEP Offering, EEP conveyed a 39% interest in Midcoast Operating to MEP. Under the Midcoast Operating LP Agreement, EEP and MEP each have the option to contribute its proportionate share of additional capital to Midcoast Operating if any additional capital contributions are necessary to fund capital expenditures or other growth projects. To the extent that MEP or EEP elect not to make any such capital contributions, the contributing party will be permitted to make additional capital contributions in exchange for additional interests in Midcoast Operating. EEP can elect not to participate in certain growth projects. We expect to participate proportionately in these natural gas capital projects, although there is no guarantee that we will do so.

Restrictive Covenants

Our Credit Facilities contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.00 to 1.00 and adjust the leverage ratio to 5.50 to 1.00 during acquisition periods (as defined in the Credit

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Facilities). At December 31, 2013, we were in compliance with the covenants associated with our Credit Facilities. Our Credit Facilities also place limitations on the debt that certain of our subsidiaries may incur directly. Accordingly, it is expected that we will provide debt financing to our subsidiaries as necessary.

Our senior notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets, except in accordance with our indenture agreement. We were in compliance with these covenants at December 31, 2013.

The OLP Notes do not contain any covenants restricting us from issuing additional indebtedness by the OLP. The OLP Notes are subject to make-whole redemption rights and were issued under an indenture, referred to as the OLP Indenture, containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets, except in accordance with the OLP Indenture. We were in compliance with these covenants at December 31, 2013.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge. The Receivables Agreement was amended on September 20, 2013 and again on December 2, 2013. The Receivables Agreement and the transactions contemplated thereby were approved by the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. 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. The Partnership and MEP act in an administrative capacity as collection agents on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. The Partnership has 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 Operating and administrative-affiliate expense in our consolidated statements of income. For the year-ended December 31, 2013, the cost stemming from the discount on the receivables sold was not material. For the year-ended December 31, 2013, we sold and derecognized $2,241.5 million of receivables to the Enbridge subsidiary. For the year-ended December 31, 2013, the cash proceeds were $2,235.7 million which was remitted to the Partnership through our centralized treasury system. As of December 31, 2013, $380.1 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of December 31, 2013, we have $69.4 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 as of December 31, 2013.

Cash Requirements

Capital Spending

We expect to make additional expenditures during 2014 for the acquisition and construction of natural gas processing and crude oil transportation infrastructure. In 2014, we expect to spend approximately $1.7 billion on system enhancements and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. We expect to receive funding of approximately $1.2 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects and $0.2 million from MPC based on joint funding arrangement on the Sandpiper Project. We made expenditures of $2.8 billion for the year ended December 31, 2013, inclusive of $188.6 million in contributions to the Texas Express Pipeline and $793.5 million of expenditures that were financed by contributions from our General Partner and MPC via joint funding arrangements. At December 31, 2013, we had approximately $1,557.9 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2013.

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 our Credit Facilities 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.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance 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. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as core maintenance expenditures. Enhancement expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and core maintenance for the year ending December 31, 2014. Although we anticipate making these expenditures in 2014, 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. We made capital expenditures of $2.8 billion, including $137.0 million on core

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maintenance activities, for the year ended December 31, 2013. For the full year ending December 31, 2014, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures (in millions)
Liquids Projects	
Eastern Access Projects	$ 1,000
U.S. Mainline Expansions	635
Sandpiper	505
Line 6B 75-mile Replacement Program	20
Liquids Integrity Program	270
System Enhancements	335
Core Maintenance Activities	75
	2,840
Less joint funding from:	
General Partner	1,225
Third parties	190
Liquids Total	1,425
Natural Gas Projects	
Beckville Cryogenic Processing Plant	$ 110
System Enhancements	215
Core Maintenance Activities	60
	385
Less joint funding from:	
MEP	150
Natural Gas Total	235
TOTAL	$ 1,660

We maintain a comprehensive integrity management program for our pipeline systems, which relies on the latest technologies that include internal pipeline inspection tools. These internal pipeline inspection tools identify internal and external corrosion, dents, cracking, stress corrosion cracking and combinations of these conditions. We regularly assess the integrity of our pipelines utilizing the latest generations of metal loss, caliper and crack detection internal pipeline inspection tools. We also conduct hydrostatic testing to determine the integrity of our pipeline systems. Accordingly, we incur substantial expenditures each year for our integrity management programs.

Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature, while expenditures to inspect and test our pipelines are usually considered operating expenses. The capital spending components of our programs have increased over time as our pipeline systems age.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that core maintenance capital will continue to increase due to the growth of our pipeline systems and the aging of portions of these systems. Core maintenance expenditures are expected to be funded by operating cash flows.

We anticipate funding system enhancement capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate.

Environmental

Lines 6A and 6B Crude Oil Releases

During 2013, our cash flows were impacted by the approximate $157.8 million we paid for the environmental remediation, restoration and cleanup activities, excluding recognized insurance recoveries of $42.0 million, resulting from the crude oil releases that occurred in 2010 on Lines 6A and 6B of our Lakehead system.

Lakehead Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of our Lakehead system near Grand Marsh, Wisconsin. The estimate of volume of the oil released was approximately 1,700 barrels. We received a Corrective Action Order, or CAO, from PHMSA, on July 30, 2012 followed by an amended CAO, which we refer to as the PHMSA Corrective Action Orders, on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013 we received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of twelve months. In December 2014, PHMSA will again consider the status of the pipeline in light of information they acquire throughout 2014.

We have not revised our estimate for repair and remediation related costs associated with this crude oil release as of December 31, 2013 including lost revenue and excluding any fines and penalties. Despite the efforts we have made to ensure the reasonableness of our estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. We will be pursuing claims under our insurance policy, although we do not expect any recoveries to be significant.

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 interest rates and 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 interest rates or commodity prices.

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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, 2013 for each of the indicated calendar years:

	Notional	2014	2015 (in millions)	2016	2017	2018	Total [4]
Swaps							
Natural gas[1]	42,475,861	$ (0.4)	$ 0.1	$	$	$	$ (0.3)
NGL[2]	3,856,300	(7.7)	0.4				(7.3)
Crude Oil[2]	2,484,370	(2.0)	8.3	0.7			7.0
Options							
Natural gas puts purchased[1]	5,840,000	0.2	1.7				1.9
Natural gas calls written[1]	1,277,500		(0.3)				(0.3)
NGL puts purchased[2]	1,424,250	2.9	6.0				8.9
NGL calls written[2]	383,250	(1.0)	(1.0)				(2.0)
Crude Oil puts purchased[2]	273,750		1.8				1.8
Crude Oil calls written[2]	273,750		(1.9)				(1.9)
Forward contracts							
Natural gas[1]	50,863,677	0.5	0.4	0.1			1.0
NGL[2]	11,756,601	(0.1)					(0.1)
Crude Oil[2]	1,214,323	(0.5)					(0.5)
Power[3]	58,608	(0.7)					(0.7)
Totals		$ (8.8)	$ 15.5	$ 0.8	$	$	$ 7.5

(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) Notional amounts for power are recorded in Megawatt hours, or MWh.

(4) Fair values exclude credit adjustments of approximately $0.1 million of gains at December 31, 2013.

The following table provides summarized information about the timing and estimated settlement amounts of our outstanding interest rate derivatives calculated based on implied forward rates in the yield curve at December 31, 2013 for each of the indicated calendar years:

	Notional Amount	2014	2015	2016 (in millions)	2017	2018	Thereafter	Total [1]
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$ 1,200.0	$ (9.1)	$ (7.4)	$ (4.0)	$ 2.8	$ 0.4	$	$ (17.3)
Pre-issuance hedges[2]	$ 2,350.0	(132.7)		60.8				(71.9)
		$ (141.8)	$ (7.4)	$ 56.8	$ 2.8	$ 0.4	$	$ (89.2)

(1) Fair values exclude credit adjustments of approximately $7.1 million of losses at December 31, 2013.

(2) Includes $16.7 million of cash collateral at December 31, 2013.

Distributions

We make quarterly distributions to our General Partner and the holders of our limited partner interests in an amount equal to our available cash. As defined in our partnership agreement, available cash represents for any calendar quarter, the sum of all of our cash receipts plus reductions in cash reserves established in prior quarters less cash disbursements and additions to cash reserves in that calendar quarter. We establish reserves to provide for the proper conduct of our business, to stabilize distributions to our unitholders and the General Partner and, as necessary, to comply with the terms of any of our agreements or obligations. Enbridge Management, as the delegate of our General Partner under the delegation of control agreement, computes the amount of our available cash.

Enbridge Management, as the owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to our General Partner and the holders of our Class A and Class B common units, the number of i-units owned by Enbridge Management and the percentage of our total units owned by Enbridge Management will increase automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management s listed and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management s listed shares on the NYSE for the 10 trading day period immediately preceding the ex-dividend date for Enbridge Management s shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to our General Partner.

For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units that are issued when a distribution of cash is made to our General Partner and owners of our common units is treated as a distribution of available cash. As set forth in our partnership agreement, we will not make cash distributions on our i-units, but instead will distribute additional i-units such that cash is retained and used in our operations and to finance a portion of our capital expansion projects. During 2013, we distributed a total of 2,607,001 i-units through quarterly distributions to Enbridge Management, compared with 2,632,090 and 2,420,228 in 2012 and 2011, respectively.

The following table represents cash we have retained in our business since January 2011 from the in-kind distribution of additional i-units:

Distribution Payment Date	Retained for i-units	Retained from General Partner	Total Cash Retained
		(in millions)	
2013			
November 14	$ 34.1	$ 0.7	$ 34.8
August 14	28.9	0.6	29.5
May 15	28.4	0.6	29.0
February 14	22.4	0.4	22.8
	$ 113.8	$ 2.3	$ 116.1
2012			
November 14	$ 22.0	$ 0.4	$ 22.4
August 14	21.6	0.5	22.1
May 15	20.9	0.4	21.3
February 14	20.5	0.4	20.9
	$ 85.0	$ 1.7	$ 86.7
2011			
November 14	$ 19.7	$ 0.4	$ 20.1
August 12	19.4	0.4	19.8
May 13	18.4	0.4	18.8
February 14	18.2	0.3	18.5
	$ 75.7	$ 1.5	$ 77.2

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Our current annual cash distribution rate is $2.174 per unit, or $0.54350 per quarter, for the year ended December 31, 2013 compared with $2.174 per unit, or $0.54350 per quarter, for the year ended December 31, 2012. We expect that all cash distributions will be paid out of operating cash flows over the long term. However, from time to time, we may temporarily borrow under our Credit Facility or use cash retained by issuance of payment in-kind distributions for the purpose of paying cash distributions. We may do this until we realize the full impact of assets being developed on operations or to respond to short-term aberrations in our performance caused by market disruption events or depressed commodity prices. As various projects are under construction, we expect our coverage ratio to weaken as assets under construction do not generate cash flow until they enter service and the Partnership is bearing the related financial costs. We expect that our major capital expansion projects will be accretive to distributable cash flow when they are operational and the coverage ratio to improve. Long term sustainability of our distributions is a key focus of the management assigned to oversee our operation. Increases in our distribution rate are made when sustainable for the long-term and upon the approval of the Board of Directors of Enbridge Management.

Series AC Distributions

The OLP is required to pay a quarterly distribution, also referred to as the Series AC distribution amount, within 45 days of the end of each calendar quarter to the holders of the Series AC general and limited partner interests under the terms of the OLP partnership agreement. As defined in the OLP partnership agreement, the Series AC distribution amount consists of the sum of: (i) the portion of the Series AC revenue entitlement that has been collected during the quarter through the transportation rates of our Lakehead system, (ii) any other cash receipts attributable to the Series AC assets collected during the quarter, and (iii) any reduction during the quarter in the amount of the Series AC reserves established in any prior quarter that are not utilized by the OLP, less the sum of: (a) all cash expenses related to the Series AC assets for the quarter, (b) all cash interest expenses and principal reductions of net borrowings for the quarter attributable to Series AC liabilities, (c) any cash maintenance and pipeline integrity capital expenditures for the quarter that are properly allocable to the Series AC assets, (d) any other cash expenses for the quarter attributable to Series AC liabilities, and (e) any increase in Series AC reserves established to provide for the proper conduct of the business of the Series AC interests.

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the years ended December 31, 2013, 2012 and 2011 representing the noncontrolling interest in the Series AC and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount Paid to the noncontrolling interest	Total Series AC Distribution
		(in millions)		
2013				
October 31	November 14	$ 7.0	$ 14.1	$ 21.1
July 29	August 14	5.5	11.0	16.5
April 30	May 15	7.5	14.9	22.4
January 30	February 14	6.9	13.8	20.7
		$ 26.9	$ 53.8	$ 80.7
2012				
October 31	November 14	$ 6.5	$ 12.9	$ 19.4
July 30	August 14	7.2	14.4	21.6
April 30	May 15	8.4	16.8	25.2
January 30	February 14	7.9	15.8	23.7
		$ 30.0	$ 59.9	$ 89.9

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Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount Paid to the noncontrolling interest	Total Series AC Distribution
		(in millions)		
2011				
October 28	November 14	$ 7.7	$ 15.3	$ 23.0
July 28	August 12	8.8	17.7	26.5
April 28	May 13	10.8	21.6	32.4
January 28	February 14	10.9	21.8	32.7
		$ 38.2	$ 76.4	$ 114.6

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2013:

	2014	2015	2016	2017	2018	Thereafter	Total
				(in millions)			
Long-term debt and notes payable to affiliates	$ 212.0	$ 12.0	$ 647.0	$ 312.0	$ 12.0	$ 4,108.0	$ 5,303.0
Purchase commitments[(1)]	1,708.0						1,708.0
Power commitments[(2)]	8.6	5.0	5.0	5.0	5.0		28.6
Other operating leases	27.8	27.4	25.4	23.7	16.1	92.2	212.6
Right-of-way[(3)]	2.2	1.9	1.9	1.6	1.5	34.3	43.4
Product purchase obligations[(4)]	190.0	17.7	8.8	15.7	26.1	147.1	405.4
Transportation/Service contract obligations[(5)]	46.0	46.7	44.9	88.8	99.1	513.2	838.7
Fractionation agreement obligations[(6)]	63.3	63.3	63.3	63.3	63.3	276.6	593.1
Total	$ 2,257.9	$ 174.0	$ 796.3	$ 510.1	$ 223.1	$ 5,171.4	$ 9,132.8

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

(2) Represents commitments to purchase power in connection with our Liquids segment.

(3) Right-of-way payments are estimated to approximate $1.5 million to $2.2 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2018.

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

(5) 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.

(6) 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, 2013, 2012 and 2011 were $802.7 million, $388.7 million and $275.4 million, respectively.

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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, 2013	For the year ended December 31, 2012	Variance 2013 vs. 2012 Increase (Decrease)
		(in millions)	
Total cash provided by (used in):			
Operating activities	$ 1,212.4	$ 851.0	$ 361.4
Investing activities	(2,642.9)	(1,906.6)	(736.3)
Financing activities	1,367.4	860.6	506.8
Net increase (decrease) in cash and cash equivalents	(63.1)	(195.0)	131.9
Cash and cash equivalents at beginning of year	227.9	422.9	(195.0)
Cash and cash equivalents at end of period	$ 164.8	$ 227.9	$ (63.1)

Operating Activities

Net cash provided by our operating activities increased $361.4 million for the twelve month period ended December 31, 2013 compared to the same period in 2012, primarily due to an increase in our working capital accounts of $507.7 million. This increase due to our working capital accounts was partially offset by a $389.7 million decrease in net income offset by non-cash items of $248.7 million for the year ended December 31, 2013 as compared to 2012.

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

	For the year ended December 31, 2013	For the year ended December 31, 2012	Variance 2013 vs. 2012
		(unaudited; in millions)	
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	$ 125.0	$ 42.7	$ 82.3
Due from General Partner and affiliates	(12.6)	(3.1)	(9.5)
Accrued receivables	286.1	(61.8)	347.9
Inventory	(21.2)	11.1	(32.3)
Current and long-term other assets	(24.1)	(7.3)	(16.8)
Due to General Partner and affiliates	79.1	(12.5)	91.6
Accounts payable and other	85.1	(8.6)	93.7
Environmental liabilities	(174.9)	(100.3)	(74.6)
Accrued purchases	13.8	(19.1)	32.9
Interest payable	4.3	(0.9)	5.2
Property and other taxes payable	(0.7)	12.0	(12.7)
Net change in working capital accounts	$ 359.9	$ (147.8)	$ 507.7

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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 same period in 2012, is primarily the result of items listed below in addition to general timing differences for cash receipts and payment associated with our third-party accounts. The main items affecting our cash flows from operating assets and liabilities include the following:

- The change in accrued receivables and trade receivables was favorable due to the sale of $275.5 million of our net accrued receivables and $90.1 million of trade receivables 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 change in accounts payable and other was favorable due to general timing differences for cash receipts and payment associated with our third-party accounts;

- The change in our environmental liabilities resulted in a decrease to cash flow from operating activities in December 31, 2013 compared to December 31, 2012, was primarily due to increased payments on environmental costs mainly attributable to Line 6B (as discussed below); and

- The net balance in due to General Partner and affiliates was higher at December 31, 2013 than at December 31, 2012 resulting in an increase to cash flow from operating activities. The higher balance is mainly attributable to general timing differences for cash receipts and payments associated with our affiliates.

The above increase was partially offset by a decrease in net income of $389.7 million offset by a $248.7 million increase in our non-cash items for the year ended December 31, 2013 compared December 31, 2012. The increase in non-cash items primarily consisted of the following:

- Increased environmental costs of $235.5 million mainly attributed to $302.0 million in additional estimated costs recognized during 2013 related to the Line 6B crude oil release, while only recognized $55.0 million in additional estimated costs for the year ended December 31, 2012 related to the Line 6B crude oil release;

- Increased depreciation and amortization of $43.2 million due to projects placed in service in 2013;

Offsetting the non-cash item increases above were the following:

- Increased allowance for equity used during construction of $31.9 million, mainly attributable to additional construction of our Mainline and Eastern Access Projects, in addition to our construction projects on Line 6B in 2013, as compared to 2012;

- A gain on the sale of assets of $17.1 million in 2013; and

- Increased long-term inventory of $9.5 million due to our line-fill on the Texas Express pipeline in 2013.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2013 decreased by $736.3 million, compared to the 2012, primarily due to the following:

Increased additions to property, plant and equipment, net of construction payables in 2013 related to various enhancement projects of $670.0 million; and

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- Increased restricted cash balance of $69.4 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. *Liquidity and Capital Resources-Sale of Accounts Receivable*.

Financing Activities

Net cash provided by our financing activities increased $506.8 million for the year ended December 31, 2013, compared to 2012, primarily due to the following:

- Increased proceeds from the preferred unit issuance in May 2013 of $1.2 billion;
- Increased capital contributions of $797.5 million from our General Partner and its affiliates in 2013 for its ownership interests in the Mainline Expansion and Eastern Access Projects, Sandpiper, and from Midcoast Holdings for its ownership in MEP;
- Increased borrowings under our Credit Facility and the credit facility of MEP of $335.0 million; and
- Increased net proceeds from unit issuances, including our General Partner s contributions of $62.3 million.

Offsetting the increases above were the following:

- Increased net repayments on our commercial paper of $1.7 billion for the year ended December 31, 2013;
- Increased repayments on long-term debt of $100.0 million due to our 4.750% Senior Notes reaching maturity in June 2013; and
- Increased distributions to our partners of $48.6 million.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

REGULATORY MATTERS

FERC Transportation Tariffs

Effective April 1, 2013, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2013 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. This tariff rate adjustment filing also included the recovery of costs related to the Flanagan Tank Replacement Project and the Eastern Access Phase 1 Mainline Expansion Project. The Lakehead system utilizes the System Expansion Project II and the Facility Surcharge Mechanism, or FSM, which are components of our Lakehead system s overall rate structure and allows for the recovery of costs for enhancements or modifications as well as certain integrity costs to our Lakehead system.

This tariff filing increased the average transportation rate for crude oil movements from the Canadian border to the Chicago, Illinois area by an average of approximately $0.26 per barrel, to an average of approximately $1.93 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on

the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

Effective April 1, 2013, we filed updates to the calculation of the surcharges on the two previously approved expansions, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. These expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing increased transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.55 per barrel, to an average of approximately $2.06 per barrel.

On May 31, 2013, we filed FERC tariffs with effective dates of July 1, 2013, for our Lakehead, North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by the FERC which incorporated the multiplier of 1.045923, which was issued by the FERC on May 15, 2013, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with 18 C.F.R.342.3 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.05 per barrel to an average of approximately $1.98 per barrel.

Effective April 1, 2012, we filed our annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2012 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. Also included was recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order as discussed in Note 13. *Commitments and Contingencies Line 6B Pipeline Integrity Plan*. The Lakehead system utilizes the Facility Surcharge Mechanism, or FSM, which is a component of our Lakehead system s overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

The tariff rate is applicable to each barrel of crude oil that is delivered on our system on or after the effective date of the tariff. This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.22 per barrel.

Effective July 1, 2012, we filed FERC tariffs for our Lakehead, North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by FERC which incorporates the multiplier of 1.086011, which was issued by FERC on May 15, 2012, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with FERC filing 18 C.F.R.3423 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by approximately $0.07 per barrel.

The April 1, 2012 and July 1, 2012 tariff changes decreased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.15 per barrel, to an average of approximately $1.67 per barrel.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-04 which provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

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Presentation of Unrecognized Tax Benefits

In July 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-11 which requires the presentation of unrecognized tax benefit as a reduction to a deferred tax asset for a net operating loss carry forward unless specific conditions exist. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied prospectively. The adoption of this pronouncement is not anticipated to have a material impact on our 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 make every effort to comply with all applicable accounting principles and believe the proper implementation and consistent application of these 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.

Liquids Revenue Recognition

Revenues of our Liquids segment are primarily derived from two sources, interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC and contract storage revenues related to our crude oil storage assets. The tariffs established for our interstate pipelines specify the amounts to be paid by shippers for transportation services we provide between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. We recognize revenue upon delivery of products to our customers, when pricing is determinable and collectability is reasonably assured. We recognize contract storage revenues based on contractual terms under which customers pay for the option to use available storage capacity and/or a fee based on storage volumes. We recognize revenues as storage services are rendered, when pricing is determinable and collectability is reasonably assured. In our Liquids segment, we generally do not own the crude oil and liquid petroleum that we transport or store, and therefore, we do not assume significant direct commodity price risk. Some long-term take-or-pay contracts contain make-up-rights. Make-up-rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiration periods. We recognize revenue associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Oil Measurement Adjustments

Oil measurement adjustments, which include crude oil over/short balance and crude oil measurement gains/losses, are inherent in the transportation of crude oil due to evaporation, measurement differences and blending of commodities in transit in addition to other factors. We estimate our oil measurement adjustments utilizing engineering based models, which include assumptions about the type of crude oil, its market value, normal physical losses due to evaporation and capacity limitations of the system. A material change in these assumptions may result in a change to the carrying value of our oil measurement adjustments. We include the crude oil measurement gains/losses in our Operating and administrative expenses on our consolidated statements of income and the crude oil over/short balance in Accounts payable and other in the consolidated statements of financial position if the balance is a liability and in Inventory if the balance is in an asset position.

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

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectability is reasonably assured. For our Natural Gas and Marketing businesses, we estimate our current month revenue and cost of natural gas 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 based on the best available volume and price data for natural gas delivered and received, along with a true-up 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 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.

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, and, in our regulated businesses that apply the authoritative accounting provisions applicable to regulated operations, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards. Examples of enhancement expenditures include costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving, or replacing, a major segment of a pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion. We also include a portion of our capital expenditures for well-connects associated with our natural gas system assets as core maintenance expenditures.

Regulatory guidance issued by the FERC requires us to expense certain costs associated with implementing the pipeline integrity management requirements of the United States Department of Transportation s Office of Pipeline Safety. Under this guidance, costs to: (1) prepare a plan to implement the program; (2) identify high consequence areas; (3) develop and maintain a record keeping system; and (4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition continue to be capitalized. We typically expense the cost of initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects consistent with industry practice and the regulatory guidance issued by the FERC. However, we capitalize initial construction hydrostatic testing costs and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also, certain costs are capitalized such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred.

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 crude oil or 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. Goodwill is allocated to two of our segments, Natural Gas and Marketing.

Pursuant to the authoritative accounting provisions for goodwill and other intangible assets, we do not amortize goodwill, but test it for impairment annually based on carrying values 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 Natural Gas and Marketing 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 an impairment has occurred.

Assessment of Recoverability of Intangibles

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 intangibles, we compare the carrying value to the undiscounted future cash flows we expect the intangibles or the underlying assets to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles and its carrying amount exceeds its fair value, we write the intangibles 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 indebtedness and commodity activities. We define fair value as an exit price representing the expected amount 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 categorize 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, as Level 2. 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.

The approximate fair values of our long-term debt obligations are determined 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, which we use to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

We utilize a mid-market pricing convention, or the market approach, for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. 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. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable master netting agreement. 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.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil 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. In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in United States dollars, or USD. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments. In accordance with the authoritative accounting guidance, we record all derivative financial instruments to our consolidated statements of financial position at fair market value. We record the fair market value of our derivative financial instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a net basis by counterparty. Derivative balances are shown net of cash collateral received or posted where master netting agreements exist. For those instruments that qualify for hedge accounting under authoritative accounting guidance, the accounting treatment is dependent on the intended use and designation of each instrument. 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 follows:

Natural Gas and Marketing segments commodity-based derivatives Cost of natural gas and Operating revenue

Liquids segment commodity-based derivatives Operating revenue and Power

Corporate interest rate derivatives Interest expense

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 Enbridge Management 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.

Cash flow hedges are derivative financial instruments that qualify for hedge accounting treatment. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions.

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 our 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.

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.

We record the changes in fair value of derivative financial instruments designated and qualifying as effective cash flow hedges as a component of Accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge s change in fair market value is recognized immediately in earnings.

Our earnings are also affected by use of the mark-to-market method of accounting as required under United States Generally Accepted Accounting Principles, or U.S. GAAP. We use derivative financial instruments such

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as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions. However, these derivative financial instruments often do not qualify for hedge accounting treatment under authoritative accounting guidance, and as a result we record changes in the fair value of these instruments on the statement of financial position and through earnings rather than deferring them until the firm commitment or anticipated transactions affect earnings. The use of mark-to-market accounting for derivative financial instruments can cause non-cash earnings volatility resulting from changes in the underlying indices, primarily commodity prices.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in our consolidated statements of financial position at their undiscounted amounts. We always have the potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

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.

SUBSEQUENT EVENTS

Distribution to Partners

On January 30, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2014. The distribution was paid to unitholders of record as of February 7, 2014, of our available cash of $213.7 million at December 31, 2013, or $0.54350 per limited partner unit. Of this distribution, $178.4 million was paid in cash, $34.6 million was distributed in i-units to our i-unitholder and $0.7 million was retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series AC Interests

On January 30, 2014, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP paid $12.8 million to the noncontrolling interest in the Series AC, while $6.4 million was paid to us.

Distribution to MEP Partners

On January 29, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable of $0.16644 per unit for the quarter ended December 31, 2013. The distribution was paid on February 14, 2014 to unitholders of record on February 7, 2014. This amount represents the prorated minimum quarterly distribution of $0.31250 per unit, or $1.25 on an annualized basis, for the period from the completion of the Offering through December 31, 2013. MEP paid $3.5 million to its public Class A common unitholders, while $4.2 million in the aggregate was paid to EEP with respect to its Class A common units, subordinated units and general partner interest.

Credit Facilities

On February 3, 2014, EEP entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank s sole discretion, we view this arrangement as liquidity enhancement as it allows EEP to potentially reduce its reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support its hedging activities.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

INTEREST RATE RISK

We utilize both fixed and variable interest rate debt and are exposed to market risk resulting from the variable interest rates on our New Credit Facility. To the extent that we frequently issue and re-issue commercial paper at short-term interest rates and have amounts drawn under our New Credit Facility at floating rates of interest, our earnings and cash flows are exposed to changes in interest rates. This exposure is managed through periodically refinancing floating-rate bank debt with long-term fixed rate debt and through the use of interest rate derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in USD. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments.

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The following table presents the principal cash flows and related weighted average interest rates by expected maturity dates along with the carrying values and fair values of our third-party debt obligations as of December 31, 2013 and 2012.

	Average Interest Rate	December 31, 2013 Expected Maturity of Carrying Amounts by Fiscal Year								December 31, 2012	
		2014	2015	2016	2017	2018	Thereafter	Total	Fair Value	Carrying Amount	Fair Value
Liabilities							(dollars in millions)				
Fixed Rate:											
Senior Notes due 2013	4.750%	$	$	$	$	$	$	$	$	$ 200.0	$ 203.9
Senior Notes due 2014	5.350%	$ 200.0	$	$	$	$	$	$ 200.0	$ 210.0	$ 200.0	$ 215.6
Senior Notes due 2016	5.875%	$	$	$ 299.9	$	$	$	$ 299.9	$ 335.0	$ 299.9	$ 345.1
Senior Notes due 2018	7.000%	$	$	$	$	$ 99.9	$	$ 99.9	$ 118.6	$ 99.9	$ 124.6
Senior Notes due 2018	6.500%	$	$	$	$	$ 399.1	$	$ 399.1	$ 464.5	$ 398.8	$ 484.1
Senior Notes due 2019	9.875%	$	$	$	$	$	$ 500.0	$ 500.0	$ 663.9	$ 500.0	$ 710.5
Senior Notes due 2020	5.200%	$	$	$	$	$	$ 499.9	$ 499.9	$ 544.8	$ 499.9	$ 575.4
Senior Notes due 2021	4.200%	$	$	$	$	$	$ 599.1	$ 599.1	$ 599.7	$ 598.9	$ 644.2
Senior Notes due 2028	7.125%	$	$	$	$	$	$ 99.8	$ 99.8	$ 121.9	$ 99.8	$ 137.5
Senior Notes due 2033	5.950%	$	$	$	$	$	$ 199.8	$ 199.8	$ 214.4	$ 199.8	$ 244.2
Senior Notes due 2034	6.300%	$	$	$	$	$	$ 99.8	$ 99.8	$ 110.9	$ 99.8	$ 126.5
Senior Notes due 2038	7.500%	$	$	$	$	$	$ 399.0	$ 399.0	$ 503.4	$ 399.0	$ 573.8
Senior Notes due 2040	5.500%	$	$	$	$	$	$ 546.4	$ 546.4	$ 531.0	$ 546.3	$ 605.5
Junior subordinated notes due 2067	8.050%	$	$	$	$	$	$ 399.7	$ 399.7	$ 446.4	$ 399.6	$ 453.6
Variable Rate:											
Credit Facilities	8.050%	$	$	$	$	$ 335.0	$	$ 335.0	$ 335.0	$	$
Commercial Paper	0.370%	$	$	$	$ 300.0	$	$	$ 300.0	$ 300.0	$ 1,160.0	$ 1,160.0

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and 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 sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our fixed and variable rate debt obligations are issued. Our exposure to commodity price risk exists within each 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 and interest rates, 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 interest rates or commodity prices.

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The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at December 31, 2013.

Date of Maturity & Contract Type		Accounting Treatment	Notional	Average Fixed Rate(1)	Fair Value(2) December 31, 2013	Fair Value(2) December 31, 2012
				(dollars in millions)		
Contracts maturing in 2015						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (6.8)	$ (6.7)
Contracts maturing in 2017						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (13.8)	$ (16.0)
Contracts maturing in 2018						
Interest Rate Swaps	Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ 3.3	$ (1.8)
Contracts settling prior to maturity						
2014	Pre-issuance Hedges(3)	Cash Flow Hedge	$ 1,850	4.27%	$ (132.7)	$ (215.4)(4)
2016	Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 60.8	$ 8.4

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from quoted market prices at December 31, 2013 and 2012, 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 $7.1 million of losses at December 31, 2013 and $13.7 million of gains at December 31, 2012

(3) Includes $16.7 million of cash collateral at December 31, 2013.

(4) The December 31, 2012 fair value of pre-issuance hedges due in 2014 has been revised to include a fair value credit of $170.1 million for interest rate hedges originally due in December 2013. These interest rate hedges were amended to extend the maturity date to December 2014 to better reflect the expected timing of future debt issuances.

The following table provides summarized information about the timing and estimated settlement amounts of

our outstanding interest rate derivatives calculated based on implied forward rates in the yield curve at December 31, 2013 for each of the indicated calendar years:

	Notional Amount	2014	2015	2016	2017	2018	Thereafter	Total (1)
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$ 1,200.0	$ (9.1)	$ (7.4)	$ (4.0)	$ 2.8	$ 0.4	$	$ (17.3)
Pre-issuance hedges(2)	$ 2,350.0	(132.7)		60.8				(71.9)
		$ (141.8)	$ (7.4)	$ 56.8	$ 2.8	$ 0.4	$	$ (89.2)

(1) Fair values exclude credit adjustments of approximately $7.1 million of losses at December 31, 2013.

(2) Includes $16.7 million of cash collateral at December 31, 2013.

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COMMODITY PRICE RISK

Our exposure to commodity price risk exists within our Natural Gas 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, 2013					At December 31, 2012	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	536,870	$ 4.26	$ 4.27	$	$	$	$
	NGL	631,250	$ 69.29	$ 68.99	$ 0.6	$ (0.4)	$	$
Receive fixed/pay variable	Natural Gas	4,478,991	$ 3.94	$ 4.14	$ 0.1	$ (1.0)	$ 0.2	$
	NGL	2,659,300	$ 54.80	$ 57.77	$ 4.8	$ (12.7)	$ 0.9	$ (2.7)
	Crude Oil	1,573,205	$ 94.43	$ 95.67	$ 3.4	$ (5.4)	$ 5.4	$ (2.7)
Receive variable/pay variable	Natural Gas	32,752,500	$ 4.12	$ 4.11	$ 0.6	$ (0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,083,450	$ 47.81	$ 47.77	$ 0.9	$ (0.9)	$	$
	Crude Oil	50,700	$ 98.47	$ 98.10	$	$	$	$
Receive fixed/pay variable	NGL	1,335,534	$ 46.80	$ 48.44	$ 0.4	$ (2.6)	$	$
	Crude Oil	165,200	$ 96.08	$ 98.48	$	$ (0.4)	$	$
Receive variable/pay variable	Natural Gas	41,064,012	$ 4.21	$ 4.20	$ 0.9	$ (0.4)	$ 0.5	$
	NGL	9,337,617	$ 40.45	$ 40.23	$ 5.8	$ (3.7)	$	$
	Crude Oil	998,423	$ 97.16	$ 97.33	$ 1.1	$ (1.2)	$	$
Pay fixed	Power [4]	58,608	$ 35.07	$ 46.58	$	$ (0.7)	$	$ (0.8)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	565,750	$ 51.33	$ 50.56	$ 1.5	$ (1.1)	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 88.07	$ 8.3	$	$ 6.8	$ (0.2)
Receive variable/pay variable	Natural Gas	4,707,500	$ 4.02	$ 4.01	$ 0.1	$	$	$
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,802,925	$ 4.19	$ 4.14	$ 0.5	$ (0.1)	$ 0.4	$
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 83.41	$ 0.7	$	$ 0.5	$
Physical Contracts								
Receive variable/pay variable	Natural Gas	996,740	$ 4.23	$ 4.13	$ 0.1	$	$ 0.1	$

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

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

(3) The fair value is determined based on quoted market prices at December 31, 2013 and 2012, 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 $0.1 million of gains and $0.4 million of losses at December 31, 2013 and 2012, respectively.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2013 and 2012.

		At December 31, 2013					At December 31, 2012	
					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 2014								
Puts (purchased)	Natural Gas	1,825,000	$ 3.90	$ 4.19	$ 0.2	$	$	$
	NGL	493,500	$ 51.91	$ 53.47	$ 2.9	$	$ 1.3	$
Calls (written)	NGL	273,750	$ 57.93	$ 53.35	$	$ (1.0)	$	$
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.14	$ 1.7	$	$	$
	NGL	930,750	$ 53.57	$ 55.13	$ 6.0	$	$	$
	Crude Oil	273,750	$ 85.00	$ 87.74	$ 1.8	$	$	$
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.14	$	$ (0.3)	$	$
	NGL	109,500	$ 81.90	$ 81.24	$	$ (1.0)	$	$
	Crude Oil	273,750	$ 90.25	$ 87.74	$	$ (1.9)	$	$

(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, 2013 and 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

QUALITATIVE FACTORS

Hedge Accounting

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust 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, or the market approach, to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our 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.

In accordance with the applicable authoritative accounting guidance, if a derivative financial instrument does not qualify as a cash flow hedge, or is not designated as a cash flow hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in Operating revenue, Cost of natural gas and Power for our commodity-based derivatives and Interest expense for our interest rate derivatives. 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.

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 in our consolidated statements of financial position, 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 for commodity hedges and Interest expense for interest rate hedges in our consolidated statements of income 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.

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 transaction types associated with our commodity derivative financial instruments 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, representing unrealized gains and losses, included in Cost of natural gas, Operating revenue , Power or Interest expense 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. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

Transportation In our Marketing segment, 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 Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is 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 injected and the price received upon withdrawal of the natural gas 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 natural gas 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 natural gas is 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 natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

Natural Gas and NGL Options In our Natural Gas segment, we use options to hedge the forecasted commodity exposure of our 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 NGLs and natural gas until the underlying long-term transactions are settled.

Optional Natural Gas Processing Volumes In our Natural Gas segment, 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 Forward Contracts In our Natural Gas segment, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. A sub-group of physical NGL sales contracts with terms allowing for economic net settlement do not qualify for the normal purchases and normal sales, or NPNS, scope exception and 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 prices until the forward contracts are settled.

Natural Gas Forward Contracts In our Marketing segment, we use forward contracts to sell natural gas to our customers. A sub-group of physical natural gas sales contracts with terms allowing for economic net settlement do not qualify for the NPNS scope exception, and 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.

Crude Oil Contracts In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.

Power Purchase Agreements In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS scope exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure. As a result, our operating income is subject to additional volatility associated with changes in the fair value of these agreements due to fluctuations in forward power prices.

Crude Forward Contracts In our Liquids segment, we use forward contracts to fix the price of crude we purchase and store in inventory and to fix the price of crude that we sell from inventory. A sub-group of physical crude contracts with terms allowing for economic net settlement do not qualify for NPNS scope exception and 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 crude prices until the forward contracts are settled.

Except for physical power, 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 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. Relating to the power purchase agreements, commodity power purchases are immediately consumed as part of pipeline operations and are subsequently recorded as actual power expenses each period.

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 follows:

Liquids segment commodity-based derivatives Operating revenue and Power

Natural Gas and Marketing segments commodity-based derivatives Cost of natural gas and Operating revenue

Corporate interest rate derivatives Interest expense

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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 derivative fair value net gains and losses associated with the changes in fair value of our derivative financial instruments:

	December 31,		
	2013	2012	2011
		(in millions)	
Liquids segment			
Non-qualified hedges	$ (3.9)	$ 1.3	$ 14.4
Natural Gas segment			
Hedge ineffectiveness	3.3	3.1	(5.3)
Non-qualified hedges	(3.5)	1.2	21.1
Marketing			
Non-qualified hedges	(2.8)	(3.1)	0.7
Commodity derivative fair value net gains (losses)	(6.9)	2.5	30.9
Corporate			
Hedge ineffectiveness	(21.5)	(20.5)	(0.3)
Non-qualified interest rate hedges	(0.2)	(0.5)	(0.5)
Derivative fair value net gains (losses)	$ (28.6)	$ (18.5)	$ 30.1

	December 31,	
	2013	2012
	(in millions)	
Other current assets	$ 21.2	$ 28.3
Other assets, net	74.4	15.8
Accounts payable and other[1]	(172.0)	(256.7)
Other long-term liabilities	(12.3)	(68.3)
	$ (88.7)	$ (280.9)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

The changes in the net 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.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $34.4 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 years ended December 31, 2013 and 2012, unrealized commodity hedge gains of $1.7 million and losses of $6.3 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $141.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2013, will be reclassified from AOCI to earnings during the next 12 months.

During the year ended December 31, 2013 it was determined that a portion of forecasted short term debt transactions are not expected to occur, due to changing funding requirements. Since we will require less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer meet the cash flow hedging

requirements. These terminations resulted in realized losses of $5.3 million of additional interest expense for the year ended December 31, 2013.

The year ended December 31, 2013 also includes unrealized losses from reductions to AOCI for hedge ineffectiveness of approximately $29.6 million associated with interest rate hedges that were originally set to mature in December 2013. However, in November 2013, these hedges were amended to extend the maturity date to December 2014 to better reflect the expected timing of future debt issuances.

The year ended December 31, 2012 also includes unrealized losses from reductions to AOCI for hedge ineffectiveness of approximately $20.8 million associated with interest rate hedges that were originally set to mature in December 2012. However, in December 2012, these hedges were amended to extend the maturity date to December 2013 to better reflect the expected timing of future debt issuances.

In connection with our September 2011 issuance of the 2021 Notes, we paid $18.8 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the 2021 Notes. The settlement amount is being amortized from AOCI to Interest expense over the respective 10-year term of the 2021 Notes.

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

	December 31, 2013	December 31, 2012
	(in millions)	
Counterparty Credit Quality[1]		
AAA	$ 0.3	$
AA	(49.7)	(116.5)
A[2]	(40.1)	(147.7)
Lower than A	0.8	(16.7)
	$ (88.7)	$ (280.9)

(1) As determined by nationally-recognized statistical ratings organizations.

(2) Includes $16.7 million of cash collateral at December 31, 2013.

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 International Swaps and Derivatives Association, Inc., or 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, 2013 we are holding $16.7 million in cash collateral on our asset exposures, however, as of December 31, 2012, we were not holding any cash collateral on our asset exposures. 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.

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The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our interest rate and 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.

In the event that our credit ratings were to decline to the lowest level of investment grade, as determined by Standard & Poor s and Moody s, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been at the lowest level of investment grade at December 31, 2013 we would have been required to provide additional letters of credit in the amount of $14.8 million.

At December 31, 2013 and 2012, we had credit concentrations in the following industry sectors, as presented below:

	December 31, 2013	December 31, 2012
	(in millions)	
United States financial institutions and investment banking entities	$ (85.0)	$ (204.5)
Non-United States financial institutions[1]	0.8	(84.6)
Other	(4.5)	8.2
	$ (88.7)	$ (280.9)

[1] Includes $16.7 million of cash collateral at December 31, 2013.

As of December 31, 2013, we are holding $16.7 million of cash collateral on our asset exposures, and we have provided letters of credit totaling $76.1 million and $231.2 million relating to our liability exposures pursuant to the margin thresholds in effect at December 31, 2013 and 2012, respectively, under our ISDA® agreements.

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, Crude and Power) 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 change the fair value of the positions.

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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
Commodity Contracts Financial	(in millions)						
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 Price	86.37	103.04	97.24	Bbl
NGLs	$ (0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Power	$ (0.7)	Market Approach	Forward Power Price	32.40	38.98	35.07	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$ 1.3						

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

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.1 million of gains.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2012[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
Commodity Contracts Financial	(in millions)						
Natural Gas	$ 8.8	Market Approach	Forward Gas Price	3.21	4.31	3.54	MMBtu
NGLs	$ (0.4)	Market Approach	Forward NGL Price	0.25	2.21	1.40	Gal
Commodity Contracts Physical							
Natural Gas	$ 1.6	Market Approach	Forward Gas Price	3.19	4.58	3.73	MMBtu
Crude Oil	$ 2.6	Market Approach	Forward Crude Price	65.22	116.56	94.31	Bbl
NGLs	$ 3.1	Market Approach	Forward NGL Price	0.00	2.22	0.61	Gal
Power	$ (1.2)	Market Approach	Forward Power Price	30.09	36.35	32.74	MWh
Commodity Options							
Natural Gas, Crude and NGLs	$ 6.4	Option Model	Option Volatility	29%	104%	40%	
Total Fair Value	$ 20.9						

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

(2) Fair values are presented in millions and include credit valuation adjustments of approximately $0.2 million of losses.

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Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS,

SUPPLEMENTARY INFORMATION AND

CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

ENBRIDGE 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.

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Report of Independent Registered Public Accounting Firm

To the Partners of Enbridge 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 Enbridge Energy Partners, L.P. and its subsidiaries (the Partnership) at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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, 2013, based on criteria established in *Internal Control Integrated Framework* (1992) 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 integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the 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, 2014

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the year ended December 31,		
	2013	2012	2011
	(in millions, except per unit amounts)		
Operating revenue (Notes 12 and 15)	$ 6,871.2	$ 6,291.5	$ 8,764.4
Operating revenue affiliate	245.9	414.6	345.4
	7,117.1	6,706.1	9,109.8
Operating expenses:			
Cost of natural gas (Notes 6, 12 and 15)	4,829.4	4,282.2	6,899.3
Cost of natural gas affiliate	119.5	287.9	200.8
Environmental costs, net of recoveries (Note 13)	273.7	(91.3)	(113.3)
Oil measurement adjustments (Notes 2 and 17)	(26.7)	(11.5)	(63.4)
Operating and administrative (Notes 2, 12 and 13)	536.9	430.3	344.1
Operating and administrative affiliate	408.2	421.7	360.9
Power (Note 15)	147.7	148.8	144.8
Depreciation and amortization (Note 7)	388.0	344.8	339.8
	6,676.7	5,812.9	8,113.0
Operating income	440.4	893.2	996.8
Interest expense (Notes 10 and 15)	320.4	345.0	320.6
Allowance for equity used during construction (Note 19)	43.1	11.2	
Other income (expense) (Notes 13 and 19)	16.0	(1.2)	6.5
Income before income tax expense	179.1	558.2	682.7
Income tax expense (Note 16)	18.7	8.1	5.5
Net income	160.4	550.1	677.2
Less: Net income attributable to: (Note 12)			
Noncontrolling interest	88.3	57.0	53.2
Series 1 preferred unit distributions	58.2		
Accretion of discount on Series 1 preferred units	9.2		
Net income attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 4.7	$ 493.1	$ 624.0
Net income (loss) allocable to limited partner interest	$ (122.7)	$ 369.2	$ 520.5
Net income (loss) per limited partner unit (basic) (Note 4)	$ (0.39)	$ 1.27	$ 1.99
Weighted average limited partner units outstanding (basic)	316.2	290.6	262.3
Net income (loss) per limited partner unit (diluted) (Note 4)	$ (0.39)	$ 1.27	$ 1.99
Weighted average limited partner units outstanding (diluted)	316.2	290.6	262.3
Cash distributions paid per limited partner unit outstanding	$ 2.1740	$ 2.1520	$ 2.0925

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

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the year ended December 31, 2013	2012	2011
		(in millions)	
Net income	$ 160.4	$ 550.1	$ 677.2
Other comprehensive income (loss), net of tax expense (benefit) of $0.0, $0.2,and $0.3, respectively (Note 15)	243.9	(4.0)	(194.8)
Comprehensive income	404.3	546.1	482.4
Less: Comprehensive income attributable to: (Note 12)			
Noncontrolling interest	88.3	57.0	53.2
Series 1 preferred unit distributions	58.2		
Accretion of discount on Series 1 preferred units	9.2		
Other comprehensive income (loss) allocated to noncontrolling interest	(0.9)		
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 247.7	$ 489.1	$ 429.2

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

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the year ended December 31, 2013	2012	2011
		(in millions)	
Cash provided by operating activities:			
Net income	$ 160.4	$ 550.1	$ 677.2
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (Note 7)	388.0	344.8	339.8
Derivative fair value net losses (gains) (Note 15)	28.6	18.5	(30.1)
Inventory market price adjustments (Note 6)	3.4	9.8	3.6
Environmental costs, net of recoveries (Note 13)	308.1	72.6	171.2
Deferred income taxes (Note 16)	14.5	0.1	(1.1)
State income taxes (Note 16)	8.4		
Allowance for equity used during construction	(43.1)	(11.2)	
Other (Note 20)	(10.5)	14.1	21.6
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	125.0	42.7	(2.6)
Due from General Partner and affiliates	(12.6)	(3.1)	3.8
Accrued receivables	286.1	(61.8)	174.6
Inventory (Note 6)	(21.2)	11.1	37.5
Current and long-term other assets (Note 15)	(24.1)	(7.3)	(7.7)
Due to General Partner and affiliates (Note 12)	79.1	(12.5)	4.9
Accounts payable and other (Notes 5 and 15)	85.1	(8.6)	46.4
Environmental liabilities (Note 13)	(174.9)	(100.3)	(292.3)
Accrued purchases	13.8	(19.1)	(101.6)
Interest payable	4.3	(0.9)	9.6
Property and other taxes payable	(0.7)	12.0	9.6
Settlement of interest rate derivatives (Note 15)	(5.3)		(18.8)
Net cash provided by operating activities	1,212.4	851.0	1,045.6
Cash used in investing activities:			
Additions to property, plant and equipment (Note 7)	(2,409.9)	(1,739.9)	(1,045.2)
Changes in restricted cash (Note 12)	(69.4)		
Asset acquisitions	(0.9)		(46.6)
Proceeds from the sale of net assets	44.7	9.5	3.7
Investment in joint venture	(188.6)	(168.5)	
Other	(18.8)	(7.7)	(10.9)
Net cash used in investing activities	(2,642.9)	(1,906.6)	(1,099.0)
Cash provided by financing activities:			
Net proceeds from Series 1 preferred unit issuance (Note 11)	1,199.2		
Net proceeds from unit issuances (Note 11)	519.3	457.0	881.4
Distributions to partners (Note 11)	(708.9)	(660.3)	(565.7)
Repayments to General Partner (Note 12)	(12.0)	(12.0)	(12.4)
Repayments of long-term debt (Note 10)	(200.0)	(100.0)	(31.0)
Net proceeds from issuances of long-term debt (Note 10)			740.7
Net borrowings under credit facility (Note 10)	335.0		
Net commercial paper borrowings (repayments) (Note 10)	(859.9)	884.9	(609.8)
Borrowings from General Partner (Note 12)			7.0
Contribution from noncontrolling interest (Note 12)	1,148.5	350.9	3.3

Distributions to noncontrolling interest (Note 12)	(53.8)	(59.9)	(76.4)
Other			(5.7)
Net cash provided by financing activities	1,367.4	860.6	331.4
Net increase (decrease) in cash and cash equivalents	(63.1)	(195.0)	278.0
Cash and cash equivalents at beginning of year	227.9	422.9	144.9
Cash and cash equivalents at end of period	$ 164.8	$ 227.9	$ 422.9

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

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2013	2012
	(in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 164.8	$ 227.9
Restricted cash (Note 12)	69.4	
Receivables, trade and other, net of allowance for doubtful accounts of $0.5 in 2013 and $1.9 in 2012 (Note 13)	49.4	142.4
Due from General Partner and affiliates	40.5	27.2
Accrued receivables	210.2	569.7
Inventory (Note 6)	94.9	72.7
Other current assets (Note 15)	47.6	48.0
	676.8	1,087.9
Property, plant and equipment, net (Notes 7, 12 and 19)	13,176.8	10,937.6
Goodwill (Note 8)	246.7	246.7
Intangibles, net (Note 9)	263.2	257.2
Other assets, net (Note 15)	538.0	267.4
	$ 14,901.5	$ 12,796.8
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 121.4	$ 43.5
Accounts payable and other (Notes 5, 15 and 19)	822.0	646.0
Environmental liabilities (Note 13)	233.7	108.0
Accrued purchases	465.6	484.1
Interest payable	68.0	69.0
Property and other taxes payable (Note 16)	70.7	71.4
Note payable to General Partner (Note 12)	12.0	12.0
Current maturities of long-term debt (Note 10)	200.0	200.0
	1,993.4	1,634.0
Long-term debt (Note 10)	4,777.4	5,501.7
Note payable to General Partner (Note 12)	306.0	318.0
Other long-term liabilities (Notes 13, 15 and 16)	127.3	95.2
	7,204.1	7,548.9
Commitments and contingencies (Note 13)		
Partners capital (Notes 11 and 12)		
Series 1 preferred units (48,000,000 at December 31, 2013)	1,160.7	
Class A common units (254,208,428 at December 31, 2013 and December 31, 2012)	2,979.0	3,590.2
Class B common units (7,825,500 at December 31, 2013 and December 31, 2012)	65.3	83.9
i-units (63,743,099 and 41,198,424 at December 31, 2013 and December 31, 2012, respectively)	1,291.9	801.8
General Partner	301.5	299.0
Accumulated other comprehensive income (loss) (Note 15)	(76.6)	(320.5)
Total Enbridge Energy Partners, L.P. partners capital	5,721.8	4,454.4

Noncontrolling interest (Note 12)	1,975.6	793.5
Total partners capital	7,697.4	5,247.9
	$ 14,901.5	$ 12,796.8

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

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

	For the year ended December 31,					
	2013		2012		2011	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
Series 1 preferred units:						
Beginning balance		$		$		$
Allocation of proceeds and issuance costs from unit issuances	48,000,000	1,199.2				
Net income (loss) allocation						
Distributions						
Accretion of discount on preferred units		9.2				
Beneficial conversion feature of preferred units		(47.7)				
Ending balance	48,000,000	1,160.7				
Class A common units:						
Beginning balance	254,208,428	3,590.2	238,043,964	3,386.7	209,084,106	2,641.0
Net income (loss) allocation		(96.3)		306.2		430.5
Allocation of proceeds and issuance costs from unit issuances			16,164,464	418.5	28,959,858	769.5
Distributions		(552.6)		(521.2)		(454.3)
Beneficial conversion feature of preferred units		37.7				
Ending balance	254,208,428	2,979.0	254,208,428	3,590.2	238,043,964	3,386.7
Class B common units:						
Beginning balance	7,825,500	83.9	7,825,500	82.2	7,825,500	64.9
Net income (loss) allocation		(2.8)		10.1		15.6
Allocation of proceeds and issuance costs from unit issuances				8.4		18.1
Distributions		(17.0)		(16.8)		(16.4)
Beneficial conversion feature of preferred units		1.2				
Ending balance	7,825,500	65.3	7,825,500	83.9	7,825,500	82.2
i-units:						
Beginning balance	41,198,424	801.8	38,566,334	728.6	35,285,422	579.1
Net income (loss) allocation		(26.3)		50.5		72.3
Allocation of proceeds and issuance costs from unit issuances	18,774,686	508.5		22.7	860,684	77.2
Distributions	3,769,989		2,632,090		2,420,228	
Beneficial conversion feature of preferred units		7.9				
Ending balance	63,743,099	1,291.9	41,198,424	801.8	38,566,334	728.6
General Partner:						
Beginning balance		299.0		285.6		256.8
Net income allocation		130.1		126.3		105.6
General Partner contribution		10.8		9.4		18.2
Distributions		(139.3)		(122.3)		(95.0)
Beneficial conversion feature of preferred units		0.9				
Ending balance		301.5		299.0		285.6
Accumulated other comprehensive income:						
Beginning balance		(320.5)		(316.5)		(121.7)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings		27.1		28.8		86.8

Unrealized net loss on derivative financial instruments	216.8	(32.8)	(281.6)
Ending balance	(76.6)	(320.5)	(316.5)
Total Enbridge Energy Partners, L.P. partners capital at December 31,	5,721.8	4,454.4	4,166.6
Noncontrolling interest:			
Beginning balance	793.5	445.5	465.4
Capital contributions	793.6	350.9	3.3
Issuance of MEP units	354.9		
Comprehensive income:			
Net income allocation	88.3	57.0	53.2
Other comprehensive income, net of tax	(0.9)		
Distributions	(53.8)	(59.9)	(76.4)
Ending balance	1,975.6	793.5	445.5
Total partners capital at December 31,	$ 7,697.4	$ 5,247.9	$ 4,612.1

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

ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND NATURE OF OPERATIONS

General

Enbridge Energy Partners, L.P., together with its consolidated subsidiaries, which are referred to herein as we, us, our, and the Partnership, is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, natural gas gathering, treating, processing, and transmission assets and marketing assets in the United States of America. Our Class A common units are traded on the New York Stock Exchange, or NYSE, under the symbol EEP.

We were formed in 1991 by Enbridge Energy Company, Inc., our General Partner, which is an indirect, wholly-owned subsidiary of Enbridge Inc., a leading energy transportation and distribution company located in Calgary, Alberta, Canada, which we refer to as Enbridge. We were formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership, or the OLP, 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.

We are a geographically and operationally diversified organization, providing crude oil gathering, transportation and storage services, and natural gas gathering, treating, processing, marketing and transportation services in the Gulf Coast and Mid-Continent regions of the United States. We hold our assets in a series of limited liability companies and limited partnerships that we own either directly or indirectly.

Our capital accounts consist of general partner interests and limited partner interests. Our limited partner interests include Class A and Class B common units and i-units, which we collectively refer to as the limited partner units. At December 31, 2013 and 2012, our ownership interests were distributed as follows:

	2013	2012
Class A common units owned by the public	62.5%	67.1%
Class A common units owned by our General Partner	14.0%	15.1%
Class B common units owned by our General Partner	2.3%	2.5%
i-units owned by Enbridge Management [1]	19.2%	13.3%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

(1) For the years ended December 31, 2013 and 2012, our General Partner owned 11.7% and 16.8%, respectively, of Enbridge Management, which owns all of our i-units.

In July 2009, the OLP amended and restated its limited partnership agreement to establish two series of partnership interests, the Series AC and Series LH interests. The two distinct series of partnership interests were created to facilitate the financing and funding of construction costs for the United States segment of the Alberta Clipper crude oil pipeline, which we refer to as the Alberta Clipper Pipeline. All assets, liabilities and operations related to the Alberta Clipper Pipeline are designated by the Series AC interests. Our General Partner holds a 66.67% interest in the Series AC limited partner interest, while we hold a 33.329% direct Series AC limited partner interest and a 0.001% indirect Series AC general partner interest. We hold a 99.999% direct Series LH limited partner interest and a 0.001% indirect Series LH general partner interest.

In May 2012, the OLP amended and restated its limited partnership agreement to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. All assets, liabilities and operations related to the Eastern Access Projects are owned 60% by our General Partner and 40% by the Partnership as per the funding agreement we refer to as the Eastern Access Joint Funding Agreement.

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. The projects will be jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest by up to 15 percentage points. All other operations of the OLP are funded by the Partnership pursuant to the LH series of partnership interests.

In May 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our Preferred Units, representing limited partner interests in the Partnership, for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013. The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset every five years. However, these quarterly cash distributions, during the first full eight quarters ending June 30, 2015, will accrue and accumulate, which we refer to as the Payment Deferral. Thus the Partnership will accrue, but not pay these amounts until the earlier of the fifth anniversary of the issuance of such Preferred Units or the redemption of such Preferred Units by the Partnership. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A common units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions.

In May 2013, we formed a new subsidiary, Midcoast Energy Partners, L.P., or MEP. On November 13, 2013, MEP completed its initial public offering of Class A common units, representing limited partner interests in MEP. On the same date, in connection with the closing of that offering, certain transactions, among others, occurred pursuant which we effectively conveyed all of our limited liability company interests in the general partner of the operating subsidiary of MEP, or Midcoast Operating and a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units and MEP Subordinated Units, approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the contributed businesses, and a right to receive $323.4 million in cash. In addition, in connection with the closing of that offering and the closing of the underwriters exercise of its over-allotment option, we received $47.0 million from MEP for its redemption of 2,775,000 of MEP Class A common units from us. At December 31, 2013, we owned 2.893% of the outstanding MEP Class A units, 100% of the outstanding MEP Subordinated Units, 100% of MEP s general partner and 61% of the limited partner interests in Midcoast Operating.

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 in May 2002. Our General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of its directors. Enbridge Management s listed shares are traded on the NYSE under the symbol EEQ. Enbridge Management owns all of a special class of our limited partner interests that we refer to as i-units and derives all of its earnings from its investment in us.

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Enbridge Management s principal activity is managing our business and affairs pursuant to a delegation of control agreement among our General Partner, Enbridge Management and us. The delegation of control agreement provides that Enbridge Management will not amend or propose to amend our partnership agreement, allow a merger or consolidation involving us, allow a sale or exchange of all or substantially all of our assets or dissolve or liquidate us without the approval of our General Partner. In accordance with its limited liability company agreement, Enbridge Management s activities are restricted to being our limited partner and managing our business and affairs.

Enbridge Inc.

Enbridge is the indirect parent of our General Partner, and its common shares are publicly traded on the NYSE in the United States and the Toronto Stock Exchange in Canada 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 and natural gas distribution. At December 31, 2013 and 2012, Enbridge and its consolidated subsidiaries held an effective 20.6% and 21.8% ownership interest in us, respectively, through its ownership in Enbridge Management and our General Partner.

Business Segments

We conduct our business through three operating segments: Liquids, Natural Gas and Marketing.

Liquids

Our Liquids segment includes the Lakehead, North Dakota and the Mid-Continent crude oil systems. Our Lakehead system consists of a series of interstate common carrier crude oil and liquid petroleum pipelines that are regulated by the Federal Energy Regulatory Commission, the FERC, and storage assets, all of which are located in the Great Lakes and Midwest regions of the United States. Our Lakehead system, together with the Enbridge system in Canada owned by Enbridge, forms the longest liquid petroleum pipeline in the world. The Lakehead system, which spans approximately 1,900 miles and includes approximately 5,100 miles of pipe, has been in operation for more than 60 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The Lakehead system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. Our North Dakota system includes approximately 155 miles of crude oil gathering lines with proximity to the Bakken formation of the Williston Basin, which are connected to an interstate transportation line that is approximately 671 miles long and is regulated by the FERC. The North Dakota system connects directly into the Lakehead system in the state of Minnesota. Our Mid-Continent system consists of over 435 miles of active crude oil pipelines, including the FERC-regulated Ozark pipeline and approximately 20.9 million barrels of storage capacity, which serve refineries in the United States Mid-Continent region from Cushing, Oklahoma

Natural Gas

Our Natural Gas segment consists of natural gas and natural gas liquid, or NGL, gathering and transportation pipeline systems, natural gas processing and treating facilities and NGL fractionation facilities, predominantly located in active producing basins in east and north Texas, as well as the Texas Panhandle and western Oklahoma. At December 31, 2013, our Natural Gas segment is comprised of eight active and four standby natural gas treating plants and 21 active and four standby natural gas processing plants, excluding plants that are inactive based on current volumes. In addition, our Natural Gas segment includes approximately 11,600 miles of natural gas and NGL gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting NGLs, crude oil and carbon dioxide.

Marketing

Our Marketing segment primarily provides natural gas supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines as well as other interconnected natural gas pipeline systems. We primarily undertake marketing activities to increase the utilization of our natural gas pipelines, realize incremental income on gas purchased at the wellhead and provide value-added services to customers.

Our Marketing business purchases third-party pipeline transportation capacity, which provides us and our customers with access to natural gas markets that might not be directly accessible from our existing natural gas pipelines. Our Marketing business also purchases third-party storage capacity, which permits us to inject and store natural gas over various periods of time for withdrawal as these products become needed by end users of natural gas. These contracts may be denoted as firm transportation, interruptible transportation, firm storage, interruptible storage or parking and lending services. These various contract structures are used to mitigate risk associated with our natural gas purchase and sale contracts and to provide us with opportunities to competitively market natural gas products.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, or 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 those of our wholly and majority-owned subsidiaries on a consolidated basis. All significant intercompany accounts and transactions have been eliminated in consolidation. 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 in the entity. Ownership interests in our subsidiaries represented by other parties that do not control the entity are presented in our consolidated financial statements as activities and balances attributable to the noncontrolling interest.

Accounting for Regulated Operations

Our interstate liquids pipelines are subject to regulation by the FERC and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates, underlying accounting practices and ratemaking agreements with customers.

The recovery of construction, operating and other costs associated with portions of our Lakehead system are subject to the authoritative accounting provisions applicable to regulated operations. Accordingly, we record costs that are allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a non-regulated entity. Also, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities.

Allowance for Funds Used During Construction

During the construction of our pipelines that qualify for regulated accounting, we are allowed to capitalize costs that represent the estimated debt and equity costs of capital necessary to finance the construction of our pipelines. The debt and equity costs, referred to collectively as Allowance for Funds Used During Construction, or AFUDC, are capitalized as part of the costs of pipeline construction in Property, plant and equipment, net in our consolidated statements of financial position. The equity return component and interest costs related to the AFUDC are credited to Other income and Interest expense, respectively, on our consolidated statements of income. Entities that do not qualify for regulated accounting, are only allowed to capitalize interest costs related to its construction activities, while a component for equity is prohibited.

Deferred Return

Under our cost-of-service tolling methodology, we calculate tolls based on forecast volumes and costs. A difference between forecast and actual results causes an under or over collection of revenue in any given year. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized the following year. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with expansion projects through the annual cost-of-service filings with our customers and the regulator.

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

Liquids

Revenues of our Liquids segment are primarily derived from three sources, interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC, ship-or-pay agreements and contract storage revenues related to our crude oil storage assets. The tariffs established for our interstate pipelines specify the amounts to be paid by shippers for transportation services we provide between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. We recognize revenue upon delivery of products to our customers, when pricing is determinable and collectability is reasonably assured. We recognize ship-or-pay agreements when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset the cost of shipping volumes in excess of minimum commitments in future periods, subject to expiration periods. We recognize contract storage revenues based on contractual terms under which customers pay for the option to use available storage capacity and/or a fee based on storage volumes. We recognize revenues as storage services are rendered, when pricing is determinable and collectability is reasonably assured. In our Liquids segment, we generally do not own the crude oil and liquid petroleum that we transport or store, and therefore, we do not assume significant direct commodity price risk. Some long-term ship-or-pay contracts contain make-up-rights. Make-up-rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiration periods. We recognize revenue associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Natural Gas

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 generate revenues and segment gross margin principally under the following types of contractual arrangements:

Equity Investment in Joint Venture

Our natural gas and NGLs business includes our 35% aggregate interest in the Texas Express NGL system, which is comprised of two joint ventures with third parties, representing a 580-mile NGL intrastate transportation pipeline and a related NGL gathering system. We use the equity method of accounting for our 35% joint venture interest in the Texas Express NGL system as a result of our ability to significantly influence the operating activities, but insufficient ability to control these activities without the participation of a majority of the other members.

Fee-Based Arrangements

In a fee-based arrangement, we receive a fee per Mcf of natural gas processed or per gallon of NGLs produced. Under this arrangement, we have no direct commodity price exposure. We receive fee-based revenue for services, such as compression fees, gathering fees and treating fees that are recognized when volumes are received on our systems. Additionally, revenues 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 typically 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. 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. We provide additional information in Item 7A. *Quantitative and Qualitative Disclosures about Market Risk Commodity Price Risk* and Note 15. *Derivative Financial Instruments and Hedging Activities* of our consolidated financial statements in Item 8. *Financial Statements and Supplementary Data* of this report about the derivative activities we use to mitigate our exposure to commodity price risk.

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 natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we can sell at market prices and retain 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. 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, 2013, we are exposed to fluctuations in commodity prices in the near term on approximately 35% to 40% of the natural gas, NGLs and condensate we expect to receive as compensation for our services. Due to this unhedged commodity price exposure, our 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. Many of the derivative financial instruments we use do not qualify for hedge accounting. As a result we record the changes in fair value of the derivative instruments that do not qualify for hedge accounting in our operating results. This accounting treatment produces non-cash gains and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile. Some long-term ship-or-pay contracts contain make-up-rights. Make-up-rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiration periods. We recognize revenue associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires, or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Marketing

Revenues of our Marketing segment are derived from providing supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines, as well as other interconnected pipeline systems. Natural gas marketing activities are primarily undertaken to realize incremental revenues on natural gas purchased at the wellhead, and to provide other services valued by our customers. In general, natural gas purchased and sold by our Marketing business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated revenues result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At the request of some customers, we will enter into long-term fixed price purchase or sales contracts with our customers and usually will enter into offsetting positions under the same or similar terms. We recognize revenues upon delivery of natural gas to our customers, when services are rendered, pricing is determinable and collectability is reasonably assured.

Estimation of Revenue and Cost of Natural Gas

For our natural gas and marketing businesses, we estimate our current month revenue and cost of gas 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 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 based on the best available volume and price data for natural gas delivered and received, along with a true-up 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 for each of the years ended December 31, 2013, 2012 and 2011. 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 stability 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 issued check payments that have not 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 liquid hydrocarbons and natural gas. Upon disposition, product inventory is recorded to Cost of natural gas 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 administrative as incurred, or used for capital projects and new construction, and capitalized to Property, plant and equipment, net.

Oil Measurement Adjustments

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum operations. The three types of oil measurement adjustments that routinely occur on our systems include:

Physical, which result from evaporation, shrinkage, differences in measurement (including sediment and water measurement) between receipt and delivery locations and other operational conditions;

Degradation, resulting from mixing at the interface within our pipeline systems or terminal and storage facilities between higher quality light crude oil and lower quality heavy crude oil in pipelines; and

Revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Quantifying oil measurement adjustments are difficult because: (1) physical measurements of volumes are not practical, as products continuously move through our pipelines, which are primarily located underground;

(2) the extensive length of our pipeline systems; and (3) the numerous grades and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our systems and associated oil measurement adjustments. Material changes in our assumptions may result in revisions to our oil measurement estimates in the period determined.

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, and, in our regulated businesses that apply the authoritative accounting provisions applicable to regulated operations, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards. Examples of enhancement expenditures include costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving, or replacing, a major segment of a pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion. We also include a portion of our capital expenditures for well-connects associated with our natural gas system assets as core maintenance expenditures.

Regulatory guidance issued by the FERC requires us to expense certain costs associated with implementing the pipeline integrity management requirements of the United States Department of Transportation s Office of Pipeline Safety. Under this guidance, costs to: (1) prepare a plan to implement the program; (2) identify high consequence areas; (3) develop and maintain a record keeping system; and (4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition continue to be capitalized. We typically expense the cost of initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or

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construction defects consistent with industry practice and the regulatory guidance issued by the FERC. However, we capitalize initial construction hydrostatic testing costs and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also, certain costs are capitalized such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred.

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 crude oil or 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. Goodwill is allocated to two of our segments, Natural Gas and Marketing.

Pursuant to the authoritative accounting provisions for goodwill and other intangible assets, we do not amortize goodwill, but test it for impairment annually based on carrying values 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 Natural Gas and Marketing assets, (3) residual values of the assets; and (4) market

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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 an impairment has occurred.

Assessment of Recoverability of Intangibles

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 intangibles, we compare the carrying value to the undiscounted future cash flows we expect the intangibles or the underlying assets to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles and its carrying amount exceeds its fair value, we write the intangibles 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 indebtedness and commodity activities. We define fair value as an exit price representing the expected amount 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 categorize 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, as Level 2. 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.

The approximate fair values of our long-term debt obligations are determined 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, which we use to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

We utilize a mid-market pricing convention, or the market approach, for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. 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. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable master netting agreement. 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.

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 income taxes as set forth in the authoritative accounting guidance.

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.

Pursuant to the authoritative accounting guidance for accounting for uncertainty in income taxes, 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. The Partnership recognizes 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.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil 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. In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in United States dollars, or USD. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments. In accordance with the authoritative accounting guidance, we record all derivative financial instruments to our consolidated statements of financial position at fair market value. We record the fair market value of our derivative financial instruments in the consolidated statements of financial position as current and long-term assets or liabilities on a net basis by counterparty. Derivative balances are shown net of cash collateral received or posted where master netting agreements exist. For those instruments that qualify for hedge accounting under authoritative accounting guidance, the accounting treatment is dependent on the intended use and designation of each instrument. 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 follows:

Natural Gas and Marketing segments commodity-based derivatives Cost of natural gas and Operating revenue

Liquids segment commodity-based derivatives Operating revenue and Power

Corporate interest rate derivatives Interest expense

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 Enbridge Management 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.

Cash flow hedges are derivative financial instruments that qualify for hedge accounting treatment. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions.

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 our 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.

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.

We record the changes in fair value of derivative financial instruments designated and qualifying as effective cash flow hedges as a component of Accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge s change in fair market value is recognized immediately in earnings.

Our earnings are also affected by use of the mark-to-market method of accounting as required under United States Generally Accepted Accounting Principles, or U.S. GAAP. We use derivative financial instruments such as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions. However, these derivative financial instruments often do not qualify for hedge accounting treatment under authoritative accounting guidance, and as a result we record changes in the fair value of these instruments on the statement of financial position and through earnings rather than deferring them until the firm commitment or anticipated transactions affect earnings. The use of mark-to-market accounting for derivative financial instruments can cause non-cash earnings volatility resulting from changes in the underlying indices, primarily commodity prices.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense amounts we incur for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in our consolidated statements of financial position at their undiscounted amounts. We always have the potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

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 onshore 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 onshore 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.

We did not record an additional ARO for the year ended December 31, 2013 as compared to $0.4 million recorded for the year ended December 31, 2012, 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. For the year ended December 31, 2011, no additional AROs were recorded. We did not record an accretion expense for the year ended December 31, 2013 as compared to, $0.1 million and $0.1 million, recorded in our consolidated statements of income for the years ended December 31, 2012 and 2011, 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, 2013 and 2012. 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, 2013 and 2012:

	2013	2012
	(in millions)	
Balance at beginning of period	$ 3.4	$ 2.9
Additions		0.4
Accretion expense		0.1
Balance at end of period	$ 3.4	$ 3.4

3. ACQUISITIONS AND DISPOSITIONS

We accounted for each of our completed acquisitions using the acquisition method and recorded the identifiable assets acquired and liabilities assumed at their acquisition-date fair values. We have included the results of operations from each of these acquisitions in our operating results from the acquisition date.

2013 Dispositions

In November 2013, we sold one of our non-core liquids assets, the El Dorado storage facility located in Butler County, Kansas to a third party for $40.0 million. We recognized a $17.1 million gain on the El Dorado storage facility sale in other income on our consolidated statement of income. The El Dorado storage terminal consists of 11 tanks with a capacity of 1.15 million barrels in addition to two 16 pipelines. The El Dorado storage terminal is not strategic to Enbridge s future growth in the U.S. Midwest.

On November 13, 2013, in connection with the closing of the Offering, the following transactions, among others, occurred pursuant to a contribution, conveyance and assumption agreement (the Contribution Agreement) by and among EEP, MEP, the MEP General Partner, Midcoast Operating and the general partner of Midcoast Operating:

EEP conveyed a portion of its limited partner interest in Midcoast Operating to the MEP General Partner as a capital contribution with a value equal to 2.0% of the equity value of MEP after the Offering (the GP Contribution Interest);

the MEP General Partner conveyed the GP Contribution Interest to MEP in exchange for (i) 992,859 general partner units in MEP representing a continuation of its 2.0% general partner interest in MEP and (ii) the Incentive Distribution Rights (as defined in the MEP First Amended and Restated Partnership Agreement, dated as of November 13, 2013) in MEP;

EEP conveyed (1) all of its limited liability company interests in the general partner of Midcoast Operating, and (2) a limited partner interest in Midcoast Operating equal to 39.0% less the percentage of the GP Contribution Interest to MEP in exchange for (1) 4,110,056 Class A common units representing a 9.0% limited partner interest in MEP, (2) 22,610,056 subordinated units representing a 49.0% limited partner interest in MEP, (3) the right to receive $323.4 million in cash, and (iv) the right to receive $304.5 million in cash as reimbursement for certain capital expenditures made with respect to the contributed assets;

the public, through the underwriters, contributed $333,000,000 in cash (or $311,771,250, net of the underwriters discount and commissions of $19,980,000 and a structuring fee of $1,248,750 payable to Merrill Lynch, Pierce, Fenner & Smith Incorporated) to MEP in exchange for the issuance of 18,500,000 Class A common units; and

MEP redeemed the initial limited partner interests of EEP and refunded EEP s initial contribution of $980, as well as any interest or other profit that may have resulted from the investment or other use of such initial capital contribution to EEP, in proportion to such initial contribution.

Pursuant to the Contribution Agreement, MEP used the net proceeds from the exercise of the Over-Allotment Option (as defined in the Contribution Agreement), to redeem from EEP the number of Class A common units issued pursuant to the Over-Allotment Option.

2011 Acquisitions

In May 2011, we acquired natural gas pipeline assets for a final purchase price of $26.7 million in cash that are complementary to our existing East Texas system assets and expansion into the South Haynesville area.

4. NET INCOME PER LIMITED PARTNER UNIT

We allocate our net income among our Series 1 Preferred Units, or Preferred Units, Enbridge Energy Company, our General Partner, and our limited partners using first preferred unit distributions and then the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, after noncontrolling interest and preferred unit distributions, including any incentive distribution rights, embedded in the general partner interest, to our General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We also allocate any earnings in excess of distributions to our General Partner and limited partners utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners, after Preferred Unit allocations, based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement.

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In February 2011, the board of directors of Enbridge Management, as delegate of our General Partner, approved a split of our units, which was effected by a distribution on April 21, 2011 of one common unit for each common unit outstanding and one i-unit for each i-unit outstanding to unitholders of record on April 7, 2011. As a result of this unit split, we have retrospectively restated the computation of our Net income (loss) per limited partner unit (basic and diluted) in the table below and restated the number of units in our consolidated statements of financial position to present the prior year amounts on a split-adjusted basis. Additionally, the formula for distributing available cash among our General Partner and limited partners was revised to reflect this unit split, as set forth in our partnership agreement, as amended, and is presented below.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.295	2%	98%
First Target Distribution	> $0.295 to $0.35	15%	85%
Second Target Distribution	> $0.35 to $0.495	25%	75%
Over Second Target Distribution	In excess of $0.495	50%	50%

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

	For the year ended December 31, 2013	2012	2011
	(in millions, except per unit amounts)		
Net income	$ 160.4	$ 550.1	$ 677.2
Less Net income attributable to:			
Noncontrolling interest	(88.3)	(57.0)	(53.2)
Series 1 preferred unit distributions	(58.2)		
Accretion of discount on Series 1 preferred units	(9.2)		
Net income (loss) attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	4.7	493.1	624.0
Less distributions paid:			
Incentive distributions to our General Partner	(129.9)	(116.3)	(92.9)
Distributed earnings allocated to our General Partner	(14.2)	(13.0)	(11.6)
Total distributed earnings to our General Partner	(144.1)	(129.3)	(104.5)
Total distributed earnings to our limited partners	(695.6)	(636.3)	(568.3)
Total distributed earnings	(839.7)	(765.6)	(672.8)
Overdistributed earnings	$ (835.0)	$ (272.5)	$ (48.8)
Weighted average limited partner units outstanding	316.2	290.6	262.3
Basic and diluted earnings per unit:			
Distributed earnings per limited partner unit[1]	$ 2.20	$ 2.19	$ 2.17
Overdistributed earnings per limited partner unit[2]	(2.59)	(0.92)	(0.18)
Net income (loss) per limited partner unit (basic and diluted)[3]	$ (0.39)	$ 1.27	$ 1.99

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

(2) 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.

(3) For the year ended December 31,2013, 43,201,310 anti-dilutive Preferred Units were excluded from the if-converted method of calculating diluted earnings per unit.

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5. 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 $24.0 million at December 31, 2013 and $22.8 million at December 31, 2012 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.

6. INVENTORY

Our inventory is comprised of the following:

	December 31, 2013	December 31, 2012
	(in millions)	
Materials and supplies	$ 2.1	$ 1.9
Crude oil inventory	18.0	12.7
Natural gas and NGL inventory	74.8	58.1
	$ 94.9	$ 72.7

The Cost of natural gas on our consolidated statements of income includes charges totaling $3.4 million, $9.8 million and $3.6 million for the years ended December 31, 2013, 2012 and 2011, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and natural gas liquids, or NGLs, to reflect the current market value.

7. PROPERTY, PLANT AND EQUIPMENT

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

	Depreciation Rates	December 31, 2013	December 31, 2012
		(in millions)	
Land		$ 43.6	$ 40.4
Rights-of-way	2.08% - 6.41%	666.2	604.5
Pipelines	1.89% - 6.70%	8,035.8	6,662.3
Pumping equipment, buildings and tanks	1.48% - 11.11%	2,233.0	1,646.4
Compressors, meters and other operating equipment	1.80% - 20.00%	1,989.8	1,755.7
Vehicles, office furniture and equipment	1.40% - 33.33%	322.0	222.7
Processing and treating plants	2.21% - 2.73%	514.4	489.8
Construction in progress		2,077.7	1,867.2
Total property, plant and equipment		15,882.5	13,289.0
Accumulated depreciation		(2,705.7)	(2,351.4)
Property, plant and equipment, net		$ 13,176.8	$ 10,937.6

Based on our own internal study, with consideration of a third-party consultant s report, we revised depreciation rates for our North Dakota, Ozark, and Cushing liquids systems were implemented effective October 1, 2013. The asset life was extended from 22 years to 30 years due to additional reserve growth and pipeline connectivity needs. The remaining service lives will result in an approximately $16.8 million annual reduction in depreciation expense for future periods, with a reduction of $4.2 million for the year ended December 31, 2013.

In 2011 we conducted a similar internal study, with consideration of a third-party consultant s report, that also revised depreciation rates for our Anadarko, North Texas and East Texas natural gas systems. These new depreciation rates were implemented effective July 1, 2011. The average remaining service life of these natural gas systems was extended from 29 years to 36 years. The predominant factor contributing to the change in service lives was an increase in the estimated remaining reserves in the regions our natural gas systems serve, due to enhancements in fracturing technologies which will allow producers to have greater access to unconventional gas. The new remaining service lives resulted in an approximately $34.0 million annual reduction in depreciation expense for the years ended December 31, 2013 and 2012, with a reduction of $17.0 million for the year ended December 31, 2011.

8. GOODWILL

For each of the years ended December 31, 2013 and 2012, the carrying amount of goodwill was $246.7 million consisting of $226.3 million and $20.4 million related to our natural gas and marketing 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, 2013, which did not indicate the existence of impairment to goodwill associated with any of our reporting units. Even if our estimate for the fair value of our assets had been reduced by 10% in our June 30, 2013 impairment testing, no impairment charge would have resulted. The critical assumptions used in our analysis included the following:

1) A weighted average cost of capital from 7% to 8%;

2) An annual growth rate for our Natural Gas and Marketing businesses of approximately 1.0% to 3.5%;

3) A capital structure consisting of approximately 50% debt and 50% equity; and

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

We did not identify or recognize any impairments to goodwill in connection with our annual testing of goodwill for impairment during the years ended December 31, 2013, 2012 and 2011. 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, 2013.

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9. INTANGIBLES

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

	Gross Carrying Amount				Accumulated Amortization				
	Natural Gas Intangibles				Natural Gas Intangibles				
	Natural Gas Opportunities	Customer Contracts	Other	Intangible Assets, Gross	Natural Supply Opportunities	Customer Contracts	Other	Accumulated Amortization Gross	Intangible Assets, Net
	(in millions)								
December 31, 2011	$ 291.0	$ 4.4	$ 11.9	$ 307.3	$ (38.7)	$ (0.6)	$ (2.7)	$ (42.0)	$ 265.3
Additions			3.5	3.5					3.5
Amortization					(10.3)	(0.6)	(0.7)	(11.6)	(11.6)
December 31, 2012	291.0	4.4	15.4	310.8	(49.0)	(1.2)	(3.4)	(53.6)	257.2
Additions			22.3	22.3					22.3
Dispositions									
Amortization					(10.4)	(0.5)	(5.4)	(16.3)	(16.3)
December 31, 2013	$ 291.0	$ 4.4	$ 37.7	$ 333.1	$ (59.4)	$ (1.7)	$ (8.8)	$ (69.9)	$ 263.2

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 Natural Gas and Marketing segments. 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 $189.2 million 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 Natural Gas segment. 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 approximately 25 to 30 years.

Our other intangible assets are comprised of contributions we made in aid of construction for our Natural Gas and Liquids businesses. We made contributions to third parties for construction of electrical infrastructure to provide utility services for our Lakehead system and for interconnections between our natural gas systems and third-party pipelines and the related measurement equipment. In connection with our October 2010 acquisition of a common carrier trucking company, we recognized $4.4 million of additional intangibles related to workforce contracts and customer relationships. We amortize our workforce contracts and customer relationships on a straight line basis over the weighted average estimated useful life of 3 years and the underlying reserves at the time of the acquisition up to 10 years, respectively.

We estimate the annual amortization expense associated with our intangibles to approximate $16.3 million per year until December 31, 2018.

10. DEBT

The following table presents the primary components of our outstanding indebtedness with third parties and the weighted average interest rates associated with each component at the end of each period presented, before

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the effect of our interest rate hedging activities as discussed in, Note 15. *Derivative Financial Instruments and Hedging Activities*. Our indebtedness with related parties is discussed in Note 12. *Related Party Transactions*.

		December 31, 2013		2012	
	Maturity	**Rate**	**Dollars**	**Rate**	**Dollars**
			(in millions)		
Credit Facilities	2016	2.85%	$ 335.0		$
Commercial Paper[1]	2018	0.37%	300.0	0.46%	1,160.0
Senior Notes	2014-2040	6.27%	3,942.7	6.19%	4,142.1
Junior Subordinated Notes	2067	8.05%	399.7	8.05%	399.6
			4,977.4		5,701.7
Current maturities and short-term debt			(200.0)		(200.0)
Long-term debt			$ 4,777.4		$ 5,501.7

(1) Individual issuances of commercial paper generally mature in 90 days or less, but are supported by our Credit Facilities and are therefore considered long-term debt.

Credit Facilities

In September 2011, we entered into the Credit Facility. The agreement is a committed senior unsecured revolving credit facility with a letter of credit subfacility and a swing line subfacility. The Credit Facility originally permitted aggregate borrowings of up to, at any one time outstanding, $2.0 billion. On October 28, 2013, we amended our Credit Facility to extend the maturity date from September 26, 2017 to September 26, 2018 and to reduce the aggregate permitted borrowings under the Credit Facility to up to, at any one time outstanding, $1.975 billion.

On July 6, 2012, we entered into the 364-Day Credit Facility. The agreement is a committed senior unsecured revolving credit facility pursuant to which the lenders have committed to lend us up to the aggregate commitment amount: (1) on a revolving basis for a 364-day period, extendible annually at the lenders discretion; and (2) for a 364-day term on a non-revolving basis following the expiration of all revolving periods. The original agreement provided for aggregate borrowings up to $675.0 million at any one time outstanding. On February 8, 2013, we amended the 364-Day Credit Facility to reflect an increase in the lending commitments to $1.1 billion.

On July 3, 2013, we amended our 364-Day Credit Facility, to extend the revolving credit termination date to July 4, 2014 and to increase aggregate commitments under the facility by $50.0 million. Furthermore, on July 24, 2013, we further amended the 364-Day Credit Facility, by adding a new lender and increased our aggregate commitments by another $50.0 million. After these amendments, our 364-day Credit Facility now provides aggregate lending commitments of $1.2 billion.

On October 28, 2013, we amended our Credit Facilities to modify, certain terms and conditions to accommodate the proposed initial public offering of Class A common units representing limited partner interests in MEP and the transactions contemplated thereby. The amendments were effective November 13, 2013.

Our Credit Facilities provided an aggregate amount of $3.175 billion of bank credit, as of December 31, 2013, which we use to fund our general activities and working capital needs.

The amounts we may borrow under the terms of our Credit Facilities are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our Credit Facilities amounts that are at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at December 31, 2013, we could borrow approximately $2.5 billion under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$ 3,175.0
Less: Amounts outstanding under Credit Facilities	335.0
Principal amount of commercial paper outstanding	300.0
Letters of credit outstanding	76.7
Total amount we could borrow at December 31, 2013	$ 2,463.3

Individual London Interbank Offered Rate, or LIBOR rate, borrowings under the terms of our Credit Facilities may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the Credit Facilities and do not require any cash repayments or prepayments. For the year ended December 31, 2013, we did not have any LIBOR rate borrowings or base rate borrowings.

Our Credit Facilities previously were amended to exclude up to $650 million of the costs associated with the remediation of the area affected by the crude oil releases on Lines 6A and 6B from the Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA, component of the consolidated leverage ratio covenant in each of our Credit Facilities. On December 23, 2013, we amended the quarterly covenant compliance testing for each of the Credit Facilities. The amendment excludes from the definition of consolidated net income component of the consolidated leverage ratio covenant accrued but unpaid costs, expenses, fines, and penalties occurring after September 30, 2013 related to the remediation of the area affected by the crude oil releases on Lines 6A and 6B.

Our ability to comply with that covenant in the future will depend on our ability to generate sufficient internal cash flow, issue additional equity or reduce existing debt, each of which will be subject to prevailing economic conditions and other factors, including factors beyond our control. A failure to comply with that covenant could result in an event of default under the Credit Facilities, which would prohibit us from declaring or making distributions to our unitholders and would permit acceleration of, and termination of our access to, our indebtedness under the Credit Facilities, and may cause acceleration of our outstanding senior notes. Although we expect to be able to comply with this covenant under each of our Credit Facilities, there can be no assurance that in the future we will be able to do so or that our lenders will be willing to waive such non-compliance or further amend such covenants. As of December 31, 2013, we were in compliance with the terms of all of our financial covenants under the Credit Facilities.

On February 3, 2014, EEP entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank s sole discretion, we view this arrangement as liquidity enhancement as it allows EEP to potentially reduce its reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support its hedging activities.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper and is supported by our Credit Facilities. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our Credit Facilities. At December 31, 2013, we had $300.0 million of commercial paper outstanding at a weighted average interest rate of 0.37%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $859.9 million during the year ended December 31, 2013, which include gross borrowings of $12,948.4 million and gross repayments of $13,808.3 million. Our policy is that the commercial paper we can issue is limited by the amounts available under our Credit Facility up to an aggregate principal amount of $1.5 billion.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our Credit Facilities. Accordingly, such amounts have been classified as Long-term debt in our accompanying consolidated statements of financial position.

Senior Notes

All of our senior notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our senior notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $200.0 million of senior notes issued by the Enbridge Energy, Limited Partnership, or OLP, which we refer to as the OLP Notes. The borrowings under our senior notes are non-recourse to our General Partner and Enbridge Management. All of our senior notes either pay or accrue interest semi-annually and have varying maturities and terms.

The OLP, our operating subsidiary that owns the Lakehead system, has $200.0 million of senior notes outstanding representing unsecured obligations that are structurally senior to our senior notes. All of the OLP Notes pay interest semi-annually and have varying maturities and terms.

		December 31,	
	Interest Rate	**2013**	**2012**
		(in millions)	
Senior Notes due 2013	4.750%		200.0
Senior Notes due 2014	5.350%	200.0	200.0
Senior Notes due 2016	5.875%	300.0	300.0
Senior Notes due 2018	7.000%	100.0	100.0
Senior Notes due 2018	6.500%	400.0	400.0
Senior Notes due 2019	9.875%	500.0	500.0
Senior Notes due 2020	5.200%	500.0	500.0
Senior Notes due 2021	4.200%	600.0	600.0
Senior Notes due 2028	7.125%	100.0	100.0
Senior Notes due 2033	5.950%	200.0	200.0
Senior Notes due 2034	6.300%	100.0	100.0
Senior Notes due 2038	7.500%	400.0	400.0
Senior Notes due 2040	5.500%	550.0	550.0
		3,950.0	4,150.0
Unamortized discount		(7.3)	(7.9)
Total		$ 3,942.7	$ 4,142.1

Junior Subordinated Notes

The $400.0 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes, represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. We issued the Junior Notes in September 2007 for proceeds of approximately $393.0 million net of underwriting discounts, commissions and offering expenses. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, payable semi-annually in arrears on April 1 and October 1 of each year until October 1, 2017. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make cash distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017 and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047 or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part, prior to October 1, 2017, for a make-whole redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017 in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

Interest

For the years ended December 31, 2013, 2012 and 2011 our interest cost is comprised of the following:

	For the year ended December 31,		
	2013	2012	2011
		(in millions)	
Interest expense	$ 320.4	$ 345.0	$ 320.6
Interest capitalized	51.7	36.3	13.6
Interest cost incurred	$ 372.1	$ 381.3	$ 334.2
Interest paid	$ 342.3	$ 352.1	$ 314.3

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Maturities of Third Party Debt

The scheduled maturities of outstanding third-party debt, excluding any discounts at December 31, 2013, are summarized as follows in millions:

2014	200.0
2015	
2016	635.0
2017	300.0
Thereafter	3,850.0
Total	$ 4,985.0

Fair Value of Debt Obligations

The table below presents the carrying amounts and approximate fair values of our debt obligations. The carrying amounts of our outstanding commercial paper and borrowings under our Credit Facilities and prior credit facilities approximate their fair values at December 31, 2013 and 2012, respectively, due to the frequent repricing of these obligations. The fair value of our outstanding commercial paper, borrowings under our Credit Facilities are included with our long-term debt obligations below since we have the ability to refinance the amounts on a long-term basis. The approximate fair values of our long-term debt obligations are determined 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.

	December 31,			
	2013		2012	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
	(in millions)			
Commercial Paper	$ 300.0	$ 300.0	$ 1,160.0	$ 1,160.0
Credit Facilities	335.0	335.0		
4.750% Senior Notes due 2013			200.0	203.9
5.350% Senior Notes due 2014	200.0	210.0	200.0	215.6
5.875% Senior Notes due 2016	299.9	335.0	299.9	345.1
7.000% Senior Notes due 2018	99.9	118.6	99.9	124.6
6.500% Senior Notes due 2018	399.1	464.5	398.8	484.1
9.875% Senior Notes due 2019	500.0	663.9	500.0	710.5
5.200% Senior Notes due 2020	499.9	544.8	499.9	575.4
4.200% Senior Notes due 2021	599.1	599.7	598.9	644.2
7.125% Senior Notes due 2028	99.8	121.9	99.8	137.5
5.950% Senior Notes due 2033	199.8	214.4	199.8	244.2
6.300% Senior Notes due 2034	99.8	110.9	99.8	126.5
7.500% Senior Notes due 2038	399.0	503.4	399.0	573.8
5.500% Senior Notes due 2040	546.4	531.0	546.3	605.5
8.050% Junior subordinated notes due 2067	399.7	446.4	399.6	453.6
Total	$ 4,977.4	$ 5,499.5	$ 5,701.7	$ 6,604.5

11. PARTNERS CAPITAL

Our capital accounts are comprised of a 2% general partner interest and 98% limited partner interests. Our limited partner interests at December 31, 2013 include Class A common units, Class B common units, i-units and Series 1 preferred units. Our limited partners have limited rights of ownership as provided for under our partnership agreement and, as discussed below, the right to participate in our distributions. We refer to our Class A common units and Class B common units collectively as common units. Our General Partner manages our operations, subject to a delegation of control agreement with Enbridge Management, and participates in our distributions, including certain incentive income distributions.

Split of Partnership Units

Effective April 21, 2011, the board of directors of Enbridge Management, as delegate of our General Partner, approved a two-for-one split of our common units and i-units outstanding to unitholders of record on April 7, 2011. The net income per share and weighted average shares outstanding for the year ended December 31, 2011, presented in our consolidated statements of income are presented reflecting the retroactive effects of the share split.

Series 1 Preferred Unit Purchase Agreement

On May 7, 2013, the Partnership entered into the Series 1 Preferred Unit Purchase Agreement, or Purchase Agreement, with our General Partner pursuant to which we issued and sold 48,000,000 of our preferred units, representing limited partner interests in the Partnership or Preferred Units, for aggregate proceeds of approximately $1.2 billion. The closing of the transactions contemplated by the Purchase Agreement occurred on May 8, 2013.

The Preferred Units are entitled to annual cash distributions of 7.50% of the issue price, payable quarterly, which are subject to reset every five years. However, these quarterly cash distributions, during the first full eight quarters ending June 30, 2015, will accrue and accumulate, which we refer to as the Payment Deferral. Thus the Partnership will accrue, but not pay these amounts until the earlier of the fifth anniversary of the issuance of such Preferred Units or the redemption of such Preferred Units by the Partnership. The quarterly cash distribution for the three month period ended June 30, 2013 was prorated from May 8, 2013. On or after June 1, 2016, at the sole option of the holder of the Preferred Units, the Preferred Units may be converted into Class A Common Units, in whole or in part, at a conversion price of $27.78 per unit plus any accrued, accumulated and unpaid distributions, excluding the Payment Deferral, as adjusted for splits, combinations and unit distributions. At all other times, redemption of the Preferred Units, in whole or in part, is permitted only if: (1) the Partnership uses the net proceeds from incurring debt and issuing equity, which includes asset sales, in equal amounts to redeem such Preferred Units; (2) a material change in the current tax treatment of the Preferred Units occurs; or (3) the rating agencies treatment of the equity credit for the Preferred Units is reduced by 50% or more, all at a redemption price of $25.00 per unit plus any accrued, accumulated and unpaid distributions, including the Payment Deferral.

The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $47.7 million represents a beneficial conversion feature and is reflected as an increase in common and i-unit unitholders and General Partner s capital and a decrease in Preferred Unitholders capital to reflect the fair value of the Preferred Units at issuance on the Partnership s consolidated statement of partners capital for the twelve month period ended December 31, 2013. The beneficial conversion feature is considered a dividend and is distributed ratably from the issuance date of May 8, 2013 through the first conversion date, which is June 1, 2016, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders capital. The impact of the beneficial conversion feature is also included in earnings per unit for the three and twelve month periods ended December 31, 2013.

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Proceeds from the Preferred Unit issuance were used by the Partnership to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

Class A common units

The following sections present the net proceeds from our Equity Distribution Agreements and Class A common unit issuances for each of the years ended December 31, 2013 , 2012 and 2011. The proceeds from each of our offerings were generally used to repay issuances of commercial paper or amounts outstanding under our credit facilities, which we initially borrowed to finance our capital expansion projects and acquisitions, or to repay other outstanding obligations. Any proceeds we received in excess of amounts used to repay issuances of commercial paper and credit facility borrowings were temporarily invested for use in future periods to fund additional expenditures associated with our capital expansion projects.

Issuance of Class A Common Units

The following table presents the net proceeds from our Class A common unit issuances for the years ended December 31, 2012 and 2011. There were no similar issuances for the year ended December 31, 2013.

Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[1]	General Partner Contribution[2]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)			
2012					
September[3]	16,100,000	$ 28.64	$ 446.8	$ 9.4	$ 456.2
2011					
December[4]	9,775,000	$ 30.85	$ 292.0	$ 6.1	$ 298.1
September[4]	8,000,000	$ 28.20	218.3	4.6	222.9
July[4]	8,050,000	$ 30.00	233.7	4.9	238.6
2011 Totals	25,825,000		$ 744.0	$ 15.6	$ 759.6

(1) Net of underwriters fees and discounts, commissions and issuance expenses if any.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

(3) The proceeds from the September 2012 equity issuance were used to fund a portion of our capital expansion projects and for general partnership purposes.

(4) The proceeds from the December 2011 and September 2011 offerings were used to fund a portion of our capital expansion projects, while the proceeds from the July 2011 offering were used to repay a portion of our outstanding commercial paper and fund a portion of our capital expansion projects.

Equity Distribution Agreement

In June 2010, we entered into the Equity Distribution Agreement, or EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $150.0 million. The EDA allowed us to issue and sell our Class A common units at prices we deemed appropriate for our Class A common units. Under the EDA, we sold 2,118,025 Class A common units, representing 4,236,050 units after giving effect to a two-for-one split of our Class A common units that became effective on April 21, 2011, for aggregate gross proceeds of $124.8 million, of which $64.5 million are gross proceeds received in 2011. No further sales were made under that agreement. On May 27, 2011, we de-registered the remaining aggregate $25.2 million of Class A common units that were registered for sale under the initial EDA and remained unsold as of that date.

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On May 27, 2011, the Partnership entered into the Amended and Restated Equity Distribution Agreement, or Amended EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $500.0 million from the execution date of the agreement through May 20, 2014. The units issued under the Amended EDA are in addition to the units offered and sold under the EDA. The issuance and sale of our Class A common units, pursuant to the Amended EDA, may be conducted on any day that is a trading day for the New York Stock Exchange, or NYSE.

The following table presents the net proceeds from our Class A common unit issuances, pursuant to the initial EDA and the Amended EDA, during the year ended December 31, 2011. There were no similar issuances for the years ended December 31, 2013 or 2012:

Issuance Date	Number of Class A common units Issued	Average Offering Price per Class A common unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)			
2011					
January 1 to March 31[(3)]	1,773,448	$ 32.26	$ 55.9	$ 1.2	$ 57.1
April 1 to May 26[(3)]	225,200	$ 32.16	7.0	0.1	7.1
May 27 to June 30[(4)]	333,794	$ 30.30	9.9	0.2	10.1
July 1 to September 30[(4)]	751,766	$ 28.38	20.8	0.4	21.2
2011 Totals	3,084,208		$ 93.6	$ 1.9	$ 95.5

(1) Net of commissions and issuance costs of $2.2 million.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

(3) Units and unit price adjusted for the April 2011 stock split.

(4) Units issued under the Amended EDA.

In January 2011, we issued 50,650 Class A common units in connection with a land acquisition and in 2012 we issued 64,464 Class A units in connection with another land acquisition.

Class B common units

All of our outstanding Class B common units are held by our General Partner and have rights similar to our Class A common units except that they are not currently eligible for trading on the NYSE.

i-units

The i-units are a separate class of our limited partner interests, all of which are owned by Enbridge Management and are not publicly traded.

Enbridge Management, as the owner of our i-units, votes together with the holders of the common units as a single class. However, the i-units vote separately as a class on the following matters:

Any proposed action that would cause us to be treated as a corporation for United States federal income tax purposes;

Amendments to our partnership agreement that would have a material adverse effect on the holder of our i-units, unless, under our partnership agreement, the amendment could be made by our General Partner without a vote of holders of any class of units;

- The removal of our General Partner and the election of a successor general partner; and

- The transfer by our General Partner of its general partner interest to a non-affiliated person that requires a vote of holders of units under our partnership agreement and the admission of that person as a general partner.

In all cases, Enbridge Management will vote or refrain from voting its i-units in the same manner that owners of Enbridge Management s shares vote or refrain from voting their shares. Furthermore, under the terms of our partnership agreement, we agree that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as the i-units.

Investments

In September 2013, Enbridge Management completed a public offering of 8,424,686 Listed Shares, representing limited liability company interests with limited voting rights, at a price to the underwriters of $28.02 per Listed Share. Enbridge Management received net proceeds of $235.6 million, which were subsequently invested in a number of our i-units equal to the number of Listed Shares sold in the offering. We used the proceeds from our issuance of i-units to Enbridge Management to repay commercial paper, finance a portion of our capital expansion program relating to its core liquids and natural gas systems and for general corporate purposes.

In March 2013, Enbridge Management completed a public offering of 10,350,000 Listed Shares, representing limited liability company interests with limited voting rights, at a price to the underwriters of $26.44 per Listed Share. Enbridge Management received net proceeds of $272.9 million, which were subsequently invested in a number of our i-units equal to the number of Listed Shares sold in the offering. We used the proceeds from our issuance of i-units to Enbridge Management to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

In November 2011, Enbridge Management completed a private offering of 860,684 listed shares, representing limited liability company interests in Enbridge Management with limited voting rights, at a price of $29.86 per listed share. Enbridge Management received net proceeds of $25.5 million which were subsequently invested in an equal number of our i-units. Subsequently, we also received contributions of $0.7 million from our General Partner to maintain its 2% general partner interest. We used the proceeds to finance a portion of our capital expansion program relating to the expansion of our core liquids and natural gas systems and for general corporate purposes.

Distributions

Our partnership agreement requires us to distribute 100% of our available cash , which is generally defined in our partnership agreement as the sum of all cash receipts plus reductions in cash reserves established in prior quarters less cash disbursements and additions to cash reserves in that calendar quarter. Enbridge Management, as delegate of our General Partner under the delegation of control agreement, computes the amount of our available cash. Typically, our General Partner and owners of our common units will receive distributions in cash. We also retain reserves to provide for the proper conduct of our business, to stabilize distributions to our unitholders and our General Partner and, as necessary, to comply with the terms of our agreements or obligations (including any reserves required under debt instruments for future principal and interest payments and for future capital expenditures). We make distributions to our partners approximately 45 days following the end of each calendar quarter in accordance with their respective percentage interests.

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Our General Partner is granted discretion by our partnership agreement, which discretion has been delegated to Enbridge Management, subject to the approval of our General Partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Enbridge Management determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Distributions of our available cash are generally made 98% to holders of our limited partner units and 2% to our General Partner. However, distributions are subject to the payment of incentive distributions to our General Partner to the extent that certain target levels of distributions to the unitholders are achieved. The incentive distributions payable to our General Partner are 15%, 25% and 50% of all quarterly distributions of available cash that exceed target levels of $0.295, $0.35 and $0.495 per limited partner units, respectively. As set forth in our partnership agreement, we will not make cash distributions on our i-units, but instead, will distribute additional i-units such that the cash is retained and used in our operations and to finance a portion of our capital expansion projects.

Enbridge Management, as owner of the i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to our General Partner and the holders of our Class A and Class B common units, the number of i-units owned by Enbridge Management and the percentage of our total units owned by Enbridge Management will increase automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management s listed and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management s listed shares on the NYSE for the 10 trading day period immediately preceding the ex-dividend date for Enbridge Management s shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to our General Partner.

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Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Management, during the years ended December 31, 2013, 2012 and 2011.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[(2)]	Retained from General Partner[(3)]	Distribution of Cash
				(in millions, except per unit amounts)			
2013							
October 31	November 7	November 14	$ 0.54350	$ 213.1	$ 34.1	$ 0.7	$ 178.3
July 29	August 7	August 14	$ 0.54350	206.8	28.9	0.6	177.3
April 30	May 8	May 15	$ 0.54350	206.2	28.4	0.6	177.2
January 30	February 7	February 14	$ 0.54350	198.9	22.4	0.4	176.1
				$ 825.0	$ 113.8	$ 2.3	$ 708.9
2012							
October 31	November 7	November 14	$ 0.54350	$ 198.5	$ 22.0	$ 0.4	$ 176.1
July 30	August 7	August 14	$ 0.54350	187.5	21.6	0.5	165.4
April 30	May 7	May 15	$ 0.53250	180.7	20.9	0.4	159.4
January 30	February 7	February 14	$ 0.53250	180.3	20.5	0.4	159.4
				$ 747.0	$ 85.0	$ 1.7	$ 660.3
2011							
October 28	November 4	November 14	$ 0.53250	$ 173.2	$ 19.7	$ 0.4	$ 153.1
July 28	August 5	August 12	$ 0.53250	167.2	19.4	0.4	147.4
April 28	May 6	May 13	$ 0.51375	152.0	18.4	0.4	133.2
January 28[(1)]	February 4	February 14	$ 0.51375	150.5	18.2	0.3	132.0
				$ 642.9	$ 75.7	$ 1.5	$ 565.7

(1) Distributions per unit for the distribution paid are presented retrospectively applying the two-for-one split of our units.

(2) We issued 3,769,989, 2,632,090 and 2,420,228 i-units to Enbridge Management, L.L.C., the sole owner of our i-units, during 2013, 2012 and 2011 , respectively, in lieu of cash.

(3) We retained an amount equal to 2% of the i-unit distribution from our General Partner to maintain its 2% general partner interest in us.

12. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

Enbridge and its affiliates provide management and 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, nor do we have any directors. We obtain managerial, administrative and operational services from our General Partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our General Partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

Service Agreements

Our General Partner, Enbridge Management, Enbridge and affiliates of Enbridge provide managerial, administrative, operational and director services to us pursuant to service agreements, and we reimburse them for the costs of those services. Through an operational services agreement among Enbridge, Enbridge Operational Services, Inc., or EOSI, and Enbridge Pipelines Inc., or Enbridge Pipelines, both subsidiaries of Enbridge, all of whom we refer to as the Canadian service providers, and us, we are charged for the services of Enbridge employees resident in Canada. Through a general and administrative services agreement among us, our General Partner, Enbridge Management and Enbridge Employee Services, Inc., a subsidiary of our General Partner, which we refer to as EES, we are charged for the services of employees resident in the United States. The charges related to these service agreements are included in Operating and administrative expenses on our consolidated statements of income.

Operational Services Agreement

We are charged an amount by the Canadian service providers for services we are provided under the operational services agreement. The amount we are charged is established as part of the annual budget and agreed upon by us and the Canadian service providers. The amount we are charged is computed based on an estimate of the pro-rata reimbursement of each Canadian service provider s estimated annual departmental costs, net of amounts charged to other affiliates and amounts identifiable as costs of that Canadian service provider. The Canadian service providers charge us a monthly fixed fee that is computed as one-twelfth of the annual budgeted amount. Under the operational services agreement, our General Partner and Enbridge Management pay the Canadian service providers a monthly fee determined in the manner described above. At the request of Enbridge Management, the fee for these operational services provided to it in its capacity as the delegate of our General Partner are billed directly to us.

Enbridge Management and our General Partner may request that the Canadian service providers provide special additional operational services for which each, as appropriate, agrees to pay costs and expenses incurred by the Canadian service provider in connection with providing the special additional operational services. The types of services provided under the operational services agreement include:

- Executive, administrative and other services on an as required basis;
- Monitoring transportation capacity, scheduling shipments, standardizing integrity, maintenance and other operational requirements;
- Addressing regulatory matters associated with the liquids pipeline operations;
- Providing monthly measurement information, forecasts, oil accounting, invoicing and related services;
- Computer application development and support services, including liquid pipelines control center operations;
- Electrical power requirements and costs for system operations;
- Patrol and aircraft services; and
- Any other operational services required to operate existing systems and any additional systems acquired by us.

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Each year, the Canadian service providers prepare annual budgets by departmental cost center for their respective operations. After establishing a budget for the following year, the costs associated with each department are allocated to us, our General Partner, Enbridge Management and other Enbridge affiliates using one of the following three methods:

- Capital assets employed as a percentage of Enbridge-wide capital assets;
- Time-based estimates; or
- Full-time-equivalent (FTE)/headcount as a percentage of Enbridge-wide FTEs.

The total amount we reimbursed the Canadian service providers pursuant to the operational services agreement for the years ended December 31, 2013, 2012 and 2011 was $154.9 million, $133.0 million and $97.3 million, respectively.

General and Administrative Services Agreement

We, Enbridge Management and our General Partner receive services from EES under the general and administrative services agreement. Under this agreement, EES provides services to us, Enbridge Management and our General Partner and charges each recipient for services, on a monthly basis, the actual costs that it incurs for those services. Our General Partner and Enbridge Management may request that EES provide special additional general services for which each, as appropriate, agrees to pay costs and expenses incurred by EES in connection with providing the special additional general services. The types of services provided under the general and administrative services agreement include:

- Accounting, tax planning and compliance services, including preparation of financial statements and income tax returns;
- Administrative, executive, legal, human resources and computer support services;
- Insurance coverage;
- All administrative and operational services required to operate existing systems and any additional systems acquired by us and operated by EES; and
- Facilitate the business and affairs of Enbridge Management and us, including, but not limited to, public and government affairs, engineering, environmental, finance, audit, operations and operational support, safety/compliance and other services.

EES captures all costs that it incurs for providing the services by cost center in its financial system. The cost centers are determined to be Shared Service , Enbridge Energy Partners, L.P. only or Non-Enbridge Energy Partners, L.P. Shared Service cost centers are used to capture costs that are not specific to a single United States Enbridge entity but are shared among multiple United States Enbridge entities. The costs captured in the cost centers that are specific to us are charged in full to us. The costs captured in cost centers that are outside of our business unit are charged to other Enbridge entities.

The general method used to allocate the Shared Service costs is established through the budgeting process and reimbursed as follows:

- Each cost center establishes a budget.

Each cost center manager estimates the amount of time the department spends on us and entities that are not directly affiliated with us.

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Costs are accumulated monthly for each cost center.

The actual costs accumulated monthly by each cost center are allocated to us or entities that are not directly affiliated with us based on the allocation model.

We reimburse EES for its share of the allocated costs.

The total amount reimbursed by us for services received pursuant to the general and administrative services agreement for the years ended December 31, 2013, 2012 and 2011 was $284.1 million, $291.1 million and $264.3 million, respectively.

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of $51.7 million, $33.1 million and $24.9 million during 2013, 2012 and 2011, 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 it and its subsidiaries. In December 2012, the Partnership entered into an insurance allocation agreement with Enbridge and another Enbridge subsidiary, which was amended and restated on November 13, 2013 to add MEP as a party. Under this agreement, 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.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge. The Receivables Agreement was amended on September 20, 2013 and again on December 2, 2013. The Receivables Agreement and the transactions contemplated thereby were approved by the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. 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. The Partnership and MEP act in an administrative capacity as collection agents on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. The Partnership has 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 Operating and administrative-affiliate expense in our consolidated statements of income. For the year-ended December 31, 2013, the cost stemming from the discount on the receivables sold was not material. For the year-ended December 31, 2013, we sold and derecognized $2,241.5 million of receivables to the Enbridge subsidiary. For the year-ended December 31, 2013, the cash proceeds were $2,235.7 million which was remitted to the Partnership through our centralized treasury system. As of December 31, 2013, $380.1 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of December 31, 2013, we have $69.4 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 as of December 31, 2013.

Line 6A and 6B Expense Reimbursement

For the years ended December 31, 2013, 2012 and 2011, we have reimbursed Enbridge $0.5 million, $4.1 million and $7.6 million, respectively, for its assistance with the administration and clean-up efforts for our Line 6A and 6B crude oil releases. For further details related to our Line 6A and 6B crude oil releases, refer to Note 13. *Commitments and Contingences Lakehead Lines 6A and 6B Crude Oil Releases*.

Affiliate Revenues and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale. We also record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates. Included in our results for the years ended December 31, 2013, 2012 and 2011, are operating revenues of $245.9 million, $414.6 million and $345.4 million, respectively, related to these transactions.

Facilities Cost Reimbursement Agreement

In 2007, we entered into an agreement with Enbridge Pipelines to install and operate certain sampling and related facilities for the purpose of improving the quality of crude oil and the transportation services on our Lakehead system, which directly increases the transportation services revenue of Enbridge Pipelines. As compensation for installing and operating these transportation facilities, Enbridge Pipelines makes annual payments to us on a cost of service basis. The income we recorded for providing these transportation services in 2013, 2012 and 2011 was approximately $0.8 million, $0.8 million and $0.8 million, respectively.

We also purchase natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Included in our results for the years ended December 31, 2013, 2012 and 2011, are costs for natural gas purchases of $119.5 million, $285.4 million and $200.8 million, respectively, related to these purchases.

Financing Transactions with Affiliates

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Pipeline, by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Pipeline that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the Alberta Clipper Pipeline that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline, with the unpaid balance due in 2020. The approved terms for the Alberta Clipper Pipeline are described in the Alberta Clipper United States Term Sheet, which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the Federal Energy Regulatory Commission, or FERC, by the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

A summary of the cash activity for the A1 Term Note for the years ended December 31, 2013, 2012 and 2011 are as follows:

	A1 Term Note (in millions)
Balance at December 31, 2011	$ 342.0
Repayments	(12.0)
Balance at December 31, 2012	330.0
Borrowings	
Repayments	(12.0)
Balance at December 31, 2013	$ 318.0

The following table presents in millions, the scheduled maturities of the A1 Term Note based upon the $318.0 million outstanding at December 31, 2013.

	(in millions)
2014	$ 12.0
2015	12.0
2016	12.0
2017	12.0
2018	12.0
Thereafter	258.0
Total	$ 318.0

Our General Partner also made equity contributions totaling $3.3 million to the OLP during the year ended December 31, 2011 to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline. There were no similar equity contributions associated with the Alberta Clipper Pipeline for the years ended December 31, 2013 or 2012.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $52.6 million, $53.9 million and $53.2 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the years ended December 31, 2013, 2012 and 2011, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in Net income attributable to noncontrolling interest on our consolidated statements of income.

Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the years ended December 31, 2013, 2012 and 2011, representing the noncontrolling interest in the Series AC and to

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us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount Paid to the noncontrolling interest (in millions)	Total Series AC Distribution
2013				
October 31	November 14	$ 7.0	$ 14.1	$ 21.1
July 29	August 14	5.5	11.0	16.5
April 30	May 15	7.5	14.9	22.4
January 30	February 14	6.9	13.8	20.7
		$ 26.9	$ 53.8	$ 80.7
2012				
October 31	November 14	$ 6.5	$ 12.9	$ 19.4
July 30	August 14	7.2	14.4	21.6
April 30	May 15	8.4	16.8	25.2
January 30	February 14	7.9	15.8	23.7
		$ 30.0	$ 59.9	$ 89.9
2011				
October 28	November 14	$ 7.7	$ 15.3	$ 23.0
July 28	August 12	8.8	17.7	26.5
April 28	May 13	10.8	21.6	32.4
January 28	February 14	10.9	21.8	32.7
		$ 38.2	$ 76.4	$ 114.6

Joint Funding Arrangement for Eastern Access Projects

In May 2012, we amended and restated partnership agreement of the OLP to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $609.2 million and $347.9 million to the OLP for the year ended December 31, 2013 and 2012, respectively to fund its equity portion of the construction costs associated with the Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $32.1 million to our General Partner for its 60% ownership of the EA interest for the year ended December 31, 2013. We allocated earnings derived from the Eastern Access Projects in the amount of $3.4 million to our General Partner for the year ended 2012. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Joint Funding Arrangement for the U.S. Mainline Expansion

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points. All other operations are captured by the Lakehead interests. We received $12.0 million from our General Partner in consideration for our economic interest.

Our General Partner has made equity contributions totaling $159.9 million and $3.0 million to the OLP for the year ended December 31, 2013 and year ended 2012, respectively to fund its equity portion of the construction costs associated with the U.S. Mainline Expansion Projects.

We allocated earnings from the Mainline Expansion Projects in the amount of $4.3 to our General Partner for its ownership of the ME interest for the year ended December 31, 2013. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Midcoast Energy Partner, L.P.

On November 13, 2013, MEP completed its initial public offering of Class A common units, representing limited partner interests in MEP. On the same date, in connection with the closing of that offering, certain transactions, among others, occurred pursuant to which we effectively conveyed to MEP all of our limited liability company interests in the general partner of the operating subsidiary of MEP, or Midcoast Operating and a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units and MEP Subordinated Units, approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the contributed businesses, and a right to receive $323.4 million in cash. Also in connection with the closing of that offering, on November 13, 2013, we entered into the following agreements:

Omnibus Agreement

We, Midcoast Holdings, L.L.C., the general partner of MEP (the MEP General Partner), MEP, and Enbridge Inc. (Enbridge), entered in the Omnibus Agreement to which we agreed to indemnify MEP for certain matters, including environmental, right-of-way and permit matters, and we granted MEP a license to use the Enbridge logo and certain other trademarks and tradenames. The Omnibus Agreement may be terminated by the mutual agreement of the parties, or by either Enbridge or MEP in the event that we cease to control the MEP General Partner, provided that our indemnification obligations will remain in full force and effect until they expire in accordance with their respective terms.

Under the Omnibus Agreement, we also agreed to indemnify MEP for all known and certain unknown environmental liabilities that are associated with the ownership or operation of MEP s assets arising prior to the closing of that offering, in each case that are identified prior to the third anniversary of the closing of that offering. Our obligation to indemnify MEP for any environmental liabilities is subject to a $500,000 aggregate deductible before MEP is entitled to indemnification. We will also indemnify MEP for failure to have certain rights-of-way, consents, licenses and permits necessary to own and operate its assets in substantially the same

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manner in which they were owned and operated prior to the closing of the Offering, including the cost of curing certain such failures that do not allow its assets to be operated in accordance with prudent industry practice, in each case that are identified prior to the third anniversary of the closing of the Offering. Our obligation to indemnify MEP for any right-of-way, consent, license or permit matters will be subject to a $500,000 aggregate deductible before MEP is entitled to indemnification. There will be a $15 million aggregate cap on the amounts for which we will indemnify MEP for environmental, right-of-way, consents, licenses and permit matters under the Omnibus Agreement.

Intercorporate Services Agreement

We entered into an Intercorporate Service Agreement (the Intercorporate Services Agreement) with MEP, pursuant to which we will provide MEP with the following services:

- executive, management, business development, administrative, legal, human resources, records and information management, public affairs, investor relations, government relations and computer support services;
- accounting and tax planning and compliance services, including preparation of financial statements and income tax returns, unitholder tax reporting and audit and treasury services;
- strategic insurance advice, planning and claims management and related support services, and arrangement of insurance coverage as required;
- facilitation of capital markets access and financing services, cash management and related banking services, financial structuring and advisory services, as well as credit support for MEP s subsidiaries and affiliates on an as-needed basis for projects, transactions or other purposes;
- operational and technical services, including integrity, safety, environmental, project management, engineering, fundamentals analysis and regulatory, and pipeline control and field operations; and
- such other services as MEP may request.

Under the Intercorporate Services Agreement, MEP will reimburse the Partnership and its affiliates for the costs and expenses incurred in providing such services to MEP; however, we have 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.

Financial Support Agreement

We entered into a Financial Support Agreement with Midcoast Operating (the Financial Support Agreement), pursuant to which we 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, our support of Midcoast Operating s and its wholly owned subsidiaries obligations will terminate on the earlier to occur of (1) November 13, 2017 and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in MEP), less than 20% of the total outstanding limited partner interests in Midcoast Operating.

The Financial Support Agreement also provides that if MEPs bank credit agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. We also have agreed

to subordinate our right to payment on obligations owed under the Financial Support Agreement and Working Capital Credit Facility (defined below) and liens, if secured, to the rights of the lenders under the MEP credit agreement.

Amended and Restated Allocation Agreement

On November 13, 2013, in connection with the closing of the Offering, MEP entered into an Amended and Restated Allocation Agreement (the Insurance Allocation Agreement), by and among MEP, Enbridge, EEP and Enbridge Income Fund Holdings Inc., in order to participate in the comprehensive insurance program that is maintained by Enbridge for it and its subsidiaries. Under the Insurance Allocation Agreement, in the unlikely event that multiple insurable incidents occur that exceed coverage limits within the same insurance period, the total insurance coverage available to Enbridge and its subsidiaries under the insurance program will be allocated among the participating Enbridge entities on an equitable basis.

Working Capital Credit Facility

We entered into a $250.0 million Working Capital Loan Agreement (the Working Capital Credit Facility), by and between Midcoast Operating, as borrower, and the Partnership, as lender. The facility is available exclusively to fund Midcoast Operating working capital borrowings. Borrowings under the facility are scheduled to mature on November 13, 2017 and accrue interest at a per annum rate of LIBOR plus 2.5%. The Partnership s commitment to lend pursuant to the Working Capital Credit Facility will end on the earlier of the facility s maturity (by acceleration or otherwise) and the date on which we own less than 20% of the outstanding limited partner interests in Midcoast Operating. If our commitment to lend has terminated before the facility has matured (by acceleration or otherwise), then the aggregate amount of all outstanding borrowings under the facility will automatically convert to a term loan that will bear interest at LIBOR (calculated as of the conversion date) plus 2.5%. Midcoast Operating has agreed to pay a commitment fee on the unused commitment at a per annum rate of 0.4250%, payable each fiscal quarter.

General Partner Equity Transactions

Our General Partner owns an effective 2% general partner interest in us. Pursuant to our partnership agreement we paid cash distributions to our General Partner of $139.3 million, $122.3 million and $95.0 million for the years ended December 31, 2013, 2012, and 2011, respectively. The cash distributions we make to our General Partner exclude an amount equal to 2% of the i-units and until the conversion to Class A common units, the Class C unit distributions, which we retain from the General Partner to maintain its 2% general partner interest in us.

As of December 31, 2013 and 2012, our General Partner owned 46,518,336 Class A common units, representing a 14.0% and 16.0% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $101.1 million, $100.1 million and $97.3 million for the years ended December 31, 2013, 2012 and 2011, respectively, with respect to its ownership of Class A common units.

As of December 31, 2013 and 2012, our General Partner also owned 7,825,500 Class B common units, representing a 2.4% and 2.5% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $17.0 million, $16.8 million and $16.4 million for the years ended December 31, 2013, 2012, and 2011, respectively, with respect to its ownership of Class B common units.

As of December 2013, our General Partner also owned 48,000,000 Series 1 Preferred Units, representing limited partner interests in the partnership.

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The following table presents our issuances of limited partner interests where our General Partner made a contribution to retain its 2% general partner interest:

Issuance Dates	Number of Class A common units Issued[4]	Offering Price per Class A common unit[2]	Net Proceeds to the Partnership[3]	General Partner Contribution	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amount)			
2012					
September	16,100,000	$ 28.64	$ 446.8	$ 9.4	$ 456.2
2011					
December	9,775,000	$ 30.85	$ 292.0	$ 6.1	$ 298.1
July 1 to September 30[5]	751,766	$ 28.38	$ 20.8	$ 0.4	$ 21.2
September	8,000,000	$ 28.20	$ 218.3	$ 4.6	$ 222.9
July	8,050,000	$ 30.00	$ 233.7	$ 4.9	$ 238.6
May 27 to June 30[5]	333,794	$ 30.30	$ 9.9	$ 0.2	$ 10.1
April 1 to May 26[1]	225,200	$ 32.16	$ 7.0	$ 0.1	$ 7.1
January 1 to March 31[1]	1,773,448	$ 32.26	$ 55.9	$ 1.2	$ 57.1

(1) Limited partnership issuances under the EDA for the periods indicated.

(2) The offering price per unit listed for the EDA issuances is a calculated average unit price for the periods indicated.

(3) Net of underwriters fees and discounts, commissions and issuance expenses.

(4) All amounts adjusted for the April 2011 stock split.

(5) Units issued under the Amended EDA.

Conflicts of Interest

Enbridge Management makes all decisions relating to the management of our business and affairs through a delegation of control agreement with our General Partner and us. Our General Partner owns the voting shares of Enbridge Management and elects all of its directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines, owns all the common stock of our General Partner. Some of our General Partner s directors and officers are also directors and officers of Enbridge and Enbridge Management and have fiduciary duties to manage the business of Enbridge and Enbridge Management in a manner that may not be in the best interests of our unitholders. Certain conflicts of interest could arise as a result of the relationships among Enbridge Management, our General Partner, Enbridge and us. Our partnership agreement and the delegation of control agreement contain provisions that allow Enbridge Management to take into account the interest of all parties in addition to those of our unitholders in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

Enbridge Management

Pursuant to the delegation of control agreement between Enbridge Management, our General Partner and us, and our partnership agreement, we pay all expenses relating to Enbridge Management. This includes Texas franchise taxes and other capital-based foreign, state and local taxes not otherwise paid or reimbursed pursuant to a tax indemnification agreement between Enbridge and Enbridge Management on behalf of Enbridge Management.

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 liquid hydrocarbon and natural gas pipeline operations, 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 environmental liabilities through insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our Liquids and Natural Gas businesses. Our General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate 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, 2013 and 2012, we had $25.8 million and $18.3 million, respectively, included in Other long-term liabilities, that we have accrued for costs we have incurred primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Lakehead Lines 6A & 6B Crude Oil Releases

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of our Lakehead system was reported near Marshall, Michigan. We estimate that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 38 miles of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. In response to the release, a unified command structure was established under the jurisdiction of the Environmental Protection Agency, or EPA, the Michigan Department of Natural Resources and Environment, or MDNRE, and other federal, state and local agencies.

As of December 31, 2013, we have revised our total cost estimate to $1,122.0 million, primarily due to an estimate of extended period of oversight by regulators and increased dredging activity, which is an increase of $302.0 million as compared to December 31, 2012. This total estimate is before insurance recoveries and excluding additional fines and penalties other than the fines and penalties of $29.6 million discussed in *Lines 6A & 6B Fines and Penalties* below. On March 14, 2013, we received an order from the EPA, or the Environmental Protection Agency, which we refer to as the Order, that defined the scope which requires additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. We submitted our initial proposed work plan required by the EPA on April 4, 2013, and we resubmitted the workplan on April 23, 2013. The EPA approved the Submerged Oil Recovery and Assessment workplan, or SORA, with modifications on May 8, 2013. We incorporated the modification and submitted an approved SORA on May 13, 2013. The Order states that the work must be completed by December 31, 2013. At this time we have completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta. We are in the process of working with the EPA to ensure this work is completed as soon as reasonably possible, inclusive of obtaining the necessary state and local permitting that is required and considering weather conditions.

The $175.0 million increase in the total cost estimate during the three month period ending March 31, during 2013, was attributable to additional work required by the Order. The $40.0 million increase during the three month period ending June 30, 2013 was attributable to further refinement and definition of the additional dredging scope per the Order and associated environmental, permitting, waste removal and other related costs. The $87.0 million increase during the three month period ending December 31, 2013 was attributable to increased dredge activity in and around Morrow Lake and the delta area and civil penalties under the Clean Water Act of the United States as discussed in *Lines 6A & 6B Fines and Penalties* below. The actual costs incurred may differ from the foregoing estimate as we complete the work plan with the EPA related to the Order and work with other regulatory agencies to assure that our work plan complies with their requirements. Any such incremental costs will not be recovered under our insurance policies as our costs for the incident at December 31, 2013 exceeded the limits of our insurance coverage.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at December 31, 2013. Our estimates do not include amounts we have capitalized or any claims associated with the release that may later become evident and is before any insurance recoveries and excludes fines and penalties from other governmental agencies other than the fines and penalties discussed in *Lines 6A & 6B Fines and Penalties below*. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

The material components underlying our total estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release include the following:

	(in millions)
Response personnel and equipment	$ 508
Environmental consultants	200
Professional, regulatory and other	414
Total	$ 1,122

For the years ended December 31, 2013, 2012 and 2011, we made payments of $156.3 million, $134.0 million and $276.6 million, respectively, for costs associated with the Line 6B crude oil release. For the year ended December 31, 2013, we recognized a $3.0 million impairment for homes purchased due to the Line 6B crude oil release which is included in the Environmental costs, net of recoveries on our consolidated statements of income. For the years ended December 31, 2013 and 2012, we had a remaining estimated liability of $258.9 million and $115.8 million, respectively. Additionally, we recognized $42.0 million, $170.0 million and $335.0 million, respectively, of insurance recoveries in our consolidated statements of income for the years ended December 31, 2013, 2012 and 2011, respectively.

We expect to make payments for additional costs associated with extended submerged oil recovery operations including reassessment, remediation and restoration of the area and air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All the initiatives we will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Line 6A Crude Oil Release

A release of crude oil from Line 6A of our Lakehead system was reported in an industrial area of Romeoville, Illinois on September 9, 2010. We estimate that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. We completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

We are continuing to monitor the areas affected by the crude oil release from Line 6A of our Lakehead system for any additional requirements. We have completed the cleanup, remediation and restoration of the areas affected by the release. On October 21, 2013, the National Transportation Safety Board, or NTSB, publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois on September 9, 2010, which states that the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below our oil pipeline.

In connection with this crude oil release, the total cost estimate as of December 31, 2013 remains at approximately $48.0 million, before insurance recoveries and excluding fines and penalties. These costs included the emergency response, environmental remediation and cleanup activities associated with the crude oil release. For the years ended December 31, 2013, 2012 and 2011, we paid $1.5 million, $1.2 million and $11.0 million, respectively, related to the costs on the Line 6A release. For the year ended December 31, 2013, we had no remaining estimated liability and for the year ended December 31, 2012 we had liability of $1.4 million.

We continue to monitor this estimate based upon actual invoices received and paid for the personnel, equipment and services provided by our vendors and currently available facts specific to these circumstances, existing technology and presently enacted laws and regulations to determine if our estimate should be updated. We have the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. We are also pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

We included those costs we considered probable and that we could reasonably estimate for purposes of determining our expected losses associated with the Line 6A release. Our estimates do not include consideration for any unasserted claims associated with the release that may later become evident, nor have we considered any potential recoveries from third-parties that may later be determined to have contributed to the release.

Lines 6A & 6B Fines and Penalties

Our estimated costs for Line 6A do not include an estimate for fines and penalties at December 31, 2013, which may be imposed by the EPA and PHMSA, in addition to other federal, state and local governmental agencies. As of December 31, 2013, our estimated costs to the Line 6B crude oil release included in the total $29.6 million in fines and penalties for the Line 6B crude oil release. Included in this total is $3.7 million in civil penalties assessed by PHMSA that we paid during the third quarter of 2012. The total also includes $22.0 million we recognized in the fourth quarter of 2013 related to an estimate of the minimum amount of civil penalties under the Clean Water Act of the United States in respect of the Line 6B crude oil release. While no final fine or penalty has been assessed or agreed to date, we believe that, based on the best information available at this time, the $22.0 million represents the minimum estimated amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed to with the relevant governmental agencies. The Clean Water Act assesses a minimum fine of $1,100 per barrel, when no gross negligence is found. The $22.0 million represents the 20,082 barrels of oil that EEP acknowledges was spilled times the $1,100 per barrel fine assessed by the Clean Water Act. Given the complexity of settlement negotiations, which we expect will continue, and the limited information available to assess the matter, we are unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Discussions with governmental agencies regarding fines and penalties are ongoing.

Due to the absence of sufficient information, we cannot provide a reasonable estimate of our liability for potential additional fines and penalties that could be assessed in connection with each of the releases. As a result, except for the penalties discussed above, we have not recorded any liability for expected fines and penalties.

Insurance Recoveries

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates that renew throughout the year. On May 1 of each year, our insurance program is up for renewal and includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry and includes coverage for environmental incidents such as those we have incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties.

The claims for the crude oil release for Line 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650.0 million for pollution liability. Based on our remediation spending through December 31, 2013, we have exceeded the limits of coverage under this insurance policy. During the third quarter 2013, we received $42.0 million of insurance recoveries for a claim we filed in connection with the Line 6B crude oil release and recognized as a reduction to environmental cost in the second quarter of 2013. We recognized $170.0 million of insurance recoveries as reductions to Environmental costs, net of recoveries in our consolidated statements of income for the year ended December 31, 2012 for the Line 6B crude oil release. As of December 31, 2013, we have recorded total insurance recoveries of $547.0 million for the Line 6B crude oil release, out of the $650.0 million aggregate limit. We expect to record receivables for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

In March 2013, we and Enbridge filed a lawsuit against the insurers of our remaining $145.0 million coverage, as one particular insurer is disputing our recovery eligibility for costs related to our claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of our recovery with that insurer. We received a partial recovery payment of $42.0 million from the other remaining insurers and have since amended our lawsuit, such that it now includes only one insurer. While we believe that our claims for the remaining $103.0 million are covered under the policy, there can be no assurance that we will prevail in this lawsuit.

We are pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained. Additionally, fines and penalties would not be covered under our existing insurance policy.

Effective May 1, 2013, Enbridge renewed its comprehensive property and liability insurance programs, under which we are insured through April 30, 2014, with a current liability aggregate limit of $685.0 million, including sudden and accidental pollution liability. 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 Enbridge and another Enbridge subsidiary.

Line 6B Pipeline Integrity Plan

In connection with the restart of Line 6B of our Lakehead system in September 2010, we committed to accelerate a process we had initiated prior to the crude oil release to perform additional inspections, testing and

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refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement with PHMSA, we completed remediation of those pipeline anomalies identified by us between the years 2007 and 2009 that were scheduled for refurbishment and anomalies identified for action in a July 2010 PHMSA notification on schedule, within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, we also agreed to replace a 3,600-foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied into Line 6B during June 2011.

In February 2011, we filed a supplement to our Facilities Surcharge Mechanism, or FSM, which became effective on April 1, 2011 when it was approved by the FERC for recovery of $175.0 million of capital costs and $5.0 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30-year period, while operating costs will be recovered through our annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

Line 6B Replacement Program

On May 12, 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286.0 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments are being completed in components, with approximately 65 miles of segments placed in service since the first quarter of 2013. The two remaining 5-mile segments in Indiana are expected to be placed in service in components in the first quarter of 2014. The replacement program has been carried out in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through our FSM, which is part of the system-wide rates of the Lakehead system. We have subsequently revised the scope of this project to increase the diameter of all pipe segments upstream of Stockbridge, Michigan at a cost of approximately $31.0 million, which will bring the total capital for this replacement program to an estimated cost of $317.0 million. The $31.0 million of additional costs will be recovered through the FSM.

The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature.

Lakehead Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of our Lakehead system near Grand Marsh, Wisconsin. The estimate of volume of the oil released was approximately 1,700 barrels. We received a Corrective Action Order, or CAO, from PHMSA, on July 30, 2012 followed by an amended CAO, which we refer to as the PHMSA Corrective Action Orders, on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013 we received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of twelve months. In December 2014, PHMSA will again consider the status of the pipeline in light of information they acquire throughout 2014.

Our estimate for repair and remediation related costs associated with this crude oil release as of December 31, 2013 remains at approximately $10.5 million, inclusive of approximately $1.6 million of lost revenue and excluding any fines and penalties. As of December 31, 2013, there was no liability remaining as compared to December 31, 2012, which had a remaining liability of $8.9 million. Despite the efforts we have made to ensure the reasonableness of our estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. We will be pursuing claims under our insurance policy, although we do not expect any recoveries to be significant.

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Oil and Gas in Custody

Our Liquids assets transport crude oil and NGLs owned by our customers for a fee. The volume of liquid hydrocarbons in our pipeline systems at any one time varies from approximately 28 million to 54 million barrels, virtually all of which is owned by our customers. Under the terms of our tariffs, losses of crude oil from identifiable incidents not resulting from our direct negligence may be apportioned among our customers. In addition, we maintain adequate property insurance coverage with respect to crude oil and NGLs in our custody.

Approximately 40% to 50% of the natural gas volumes on our Natural Gas assets 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 Natural Gas systems 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 $2.3 million, $2.7 million and $2.5 million for the leased right-of-way agreements for the years ended December 31, 2013, 2012, and 2011, respectively.

Fines and Penalties

For the year ended December 31, 2013, our estimated cost to the Line 6B crude oil release included in the total $29.6 million in fines and penalties. Included in the total are the fines and penalties as discussed in *Lines 6A & 6B Fines and Penalties* above, but the total does not include any other fines or penalties which may be imposed by other governmental agencies.

Proceeds from Claim Settlements

For the year ended December 31, 2011, we received proceeds of $11.6 million for settlement of claims we made for payment from unrelated parties in connection with operational matters that occurred in the normal course of business. We recorded $5.6 million as a reduction to Operating and administrative expenses of our Liquids segment and $6.0 million as Other income in our consolidated statements of income for the year ended December 31, 2011 for the amounts we received in April 2011.

Legal and Regulatory Proceedings

We are a participant in various legal and regulatory proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We are also directly, or indirectly, subject to challenges by special interest groups to regulatory approvals and permits for certain of our expansion projects.

A number of governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 30 actions or claims are pending against us and our affiliates, in state and federal courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, we do not expect the outcome of these actions to be material. On July 2, 2012, PHMSA announced a NOPV related to the Line 6B crude oil release, including a civil penalty of $3.7 million that we paid during the third quarter of 2012.

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Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim has been filed against us and our affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order. The costs associated with this order are included in the estimated environmental costs accrued for the Line 6A crude oil release. We are also pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

We have accrued a provision for future legal costs and probable losses associated with the Line 6A and Line 6B crude oil releases as described above in the section titled *Lakehead Lines 6A & 6B Crude Oil Releases* of this footnote.

On July 25, 2013, the U.S. Department of Justice, or DOJ, and the EPA filed a complaint against us related to permit violations for the discharge of hydrotest water in 2010 related to the Alberta Clipper Pipeline and one of our affiliates. We have agreed to settle with the DOJ and EPA for $254 thousand related to the Alberta Clipper Pipeline portion of the permit violation.

Future Minimum Commitments

As of December 31, 2013, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

	2014	2015	2016	2017	2018	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$ 1,708.0	$	$	$	$	$	$ 1,708.0
Power commitments[2]	8.6	5.0	5.0	5.0	5.0		28.6
Other operating leases	27.8	27.4	25.4	23.7	16.1	92.2	212.6
Right-of-way[3]	2.2	1.9	1.9	1.6	1.5	34.3	43.4
Product purchase obligations[4]	190.0	17.7	8.8	15.7	26.1	147.1	405.4
Transportation/Service contract obligations[5]	46.0	46.7	44.9	88.8	99.1	513.2	838.7
Fractionation agreement obligations[6]	63.3	63.3	63.3	63.3	63.3	276.6	593.1
Total	$ 2,045.9	$ 162.0	$ 149.3	$ 198.1	$ 211.1	$ 1,063.4	$ 3,829.8

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

(2) Represents commitments to purchase power in connection with our Liquids segment.

(3) Right-of-way payments are estimated to approximate $1.5 million to $2.2 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2018.

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

(5) 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.

(6) 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, 2013, 2012 and 2011 were $590.7 million, $276.7 million and $232.0 million, respectively.

14. TRUCKING AND NGL MARKETING BUSINESS ACCOUNTING MATTERS

At our wholly-owned trucking and NGL marketing subsidiary, we identified accounting misstatements and other errors in early 2012 associated with the financial statement recognition of NGL product purchases and sales within our Natural Gas segment over a period of several years. We refer to the improper omission of product purchases as the accounting misstatements and the improper recognition of product sales as the accounting errors in the discussion which follows. The accounting misstatements were facilitated by conduct of the local management responsible for operating the subsidiary, whereby entries were made at the end of each accounting period to omit purchases of NGL product purchases from cost of goods sold included in Cost of natural gas and Accrued purchases for the purpose of creating the appearance that the subsidiary had achieved its budget. During the performance of our review of the accounting misstatements, we identified other unrelated accounting errors associated with the recognition of sales that resulted in misstatements of Inventory, Accrued receivables and Operating revenue items reported within our consolidated financial statements. The accounting misstatements and accounting errors span a period from at least 2005 through 2011 prior to their detection in 2012. The following table presents the amounts by which the end of prior period balances of Cost of natural gas, Accrued purchases, Partners Capital, Operating revenue and Accrued receivables were misstated and the effect on our net income for each of the prior periods presented (positive amounts represent overstatements of net income and negative amounts represent understatements of net income).

	2011 DR(CR) (in millions)
Income Statement	
Operating Revenue	$ (9.1)
Cost of Natural Gas	(23.8)
Net income	$ (32.9)

We have included the aggregate amount of $32.9 million, representing the 2010 accrued purchases and sales not recognized in 2010, as cost of goods sold included in Cost of natural gas and Operating revenue in our consolidated statements of income for the year ended December 31, 2011, following our determination that the previously unrecorded amounts were not material to the current or any prior period financial statements.

15. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil 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 interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each 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 interest rates and commodity prices, as well as to reduce volatility of 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 interest rates or commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with the risks discussed above through 2018 in accordance with our risk management policies.

Accounting Treatment

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust 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, or the market approach, to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our 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.

In accordance with the applicable authoritative accounting guidance, if a derivative financial instrument does not qualify as a cash flow hedge, or is not designated as a cash flow hedge, the derivative is marked-to-market each period with the increases and decreases in fair market value recorded in our consolidated statements of income as increases and decreases in Operating revenue, Cost of natural gas and Power for our commodity-based derivatives and Interest expense for our interest rate derivatives. 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.

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 in our consolidated statements of financial position, 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 for commodity hedges and Interest expense for interest rate hedges in our consolidated statements of income 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.

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 transaction types associated with our commodity derivative financial instruments 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, representing unrealized gains and losses, included in Cost of natural gas, Operating revenue , Power or Interest expense 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. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

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The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

Transportation In our Marketing segment, 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 Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is 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 injected and the price received upon withdrawal of the natural gas 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 natural gas 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 natural gas is 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 natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

Natural Gas and NGL Options In our Natural Gas segment, we use options to hedge the forecasted commodity exposure of our 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 NGLs and natural gas until the underlying long-term transactions are settled.

Optional Natural Gas Processing Volumes In our Natural Gas segment, 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 Forward Contracts In our Natural Gas segment, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. A sub-group of physical NGL sales contracts with terms allowing for economic net settlement do not qualify for the normal purchases and normal sales, or NPNS, scope exception and 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 prices until the forward contracts are settled.

Natural Gas Forward Contracts In our Marketing segment, we use forward contracts to sell natural gas to our customers. A sub-group of physical natural gas sales contracts with terms allowing for economic net settlement do not qualify for the NPNS scope exception, and 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.

Crude Oil Contracts In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.

Power Purchase Agreements In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS scope exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure. As a result, our operating income is subject to additional volatility associated with changes in the fair value of these agreements due to fluctuations in forward power prices.

Crude Forward Contracts In our Liquids segment, we use forward contracts to fix the price of crude we purchase and store in inventory and to fix the price of crude that we sell from inventory. A sub-group of physical crude contracts with terms allowing for economic net settlement do not qualify for NPNS scope exception and 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 crude prices until the forward contracts are settled.

Except for physical power, 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 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. Relating to the power purchase agreements, commodity power purchases are immediately consumed as part of pipeline operations and are subsequently recorded as actual power expenses each period.

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Derivative Positions

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

	December 31,	
	2013	2012
	(in millions)	
Other current assets	$ 21.2	$ 28.3
Other assets, net	74.4	15.8
Accounts payable and other[1]	(172.0)	(256.7)
Other long-term liabilities	(12.3)	(68.3)
	$ (88.7)	$ (280.9)

[1] Includes $16.7 million of cash collateral at December 31, 2013.

The changes in the net 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.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $34.4 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 years ended December 31, 2013 and 2012, unrealized commodity hedge gains of $1.7 million and losses of $6.3 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $141.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2013, will be reclassified from AOCI to earnings during the next 12 months.

During the year ended December 31, 2013 it was determined that a portion of forecasted short term debt transactions are not expected to occur, due to changing funding requirements. Since we will require less short-term debt than previously forecasted, we terminated several of our existing interest rate hedges used to lock-in interest rates on our short-term debt issuances as these hedges no longer meet the cash flow hedging requirements. These terminations resulted in realized losses of $5.3 million of additional interest expense for the year ended December 31, 2013.

The year ended December 31, 2013 also includes unrealized losses from reductions to AOCI for hedge ineffectiveness of approximately $29.6 million associated with interest rate hedges that were originally set to mature in December 2013. However, in November 2013, these hedges were amended to extend the maturity date to December 2014 to better reflect the expected timing of future debt issuances.

The year ended December 31, 2012 also includes unrealized losses from reductions to AOCI for hedge ineffectiveness of approximately $20.8 million associated with interest rate hedges that were originally set to mature in December 2012. However, in December 2012, these hedges were amended to extend the maturity date to December 2013 to better reflect the expected timing of future debt issuances.

In connection with our September 2011 issuance of the 2021 Notes, we paid $18.8 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the 2021 Notes. The settlement amount is being amortized from AOCI to Interest expense over the respective 10-year term of the 2021 Notes.

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

	December 31, 2013	December 31, 2012
	(in millions)	
Counterparty Credit Quality [1]		
AAA	$ 0.3	$
AA	(49.7)	(116.5)
A[2]	(40.1)	(147.7)
Lower than A	0.8	(16.7)
	$ (88.7)	$ (280.9)

(1) As determined by nationally-recognized statistical ratings organizations.

(2) Includes $16.7 million of cash collateral at December 31, 2013.

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 International Swaps and Derivatives Association, Inc., or 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, 2013 we are holding $16.7 million in cash collateral on our asset exposures, however, as of December 31, 2012, we were not holding any cash collateral on our asset exposures. 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 interest rate and 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.

In the event that our credit ratings were to decline to the lowest level of investment grade, as determined by Standard & Poor s and Moody s, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been at the lowest level of investment grade at December 31, 2013 we would have been required to provide additional letters of credit in the amount of $14.8 million.

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At December 31, 2013 and 2012, we had credit concentrations in the following industry sectors, as presented below:

	December 31, 2013	December 31, 2012
	(in millions)	
United States financial institutions and investment banking entities	$ (85.0)	$ (204.5)
Non-United States financial institutions[(1)]	0.8	(84.6)
Other	(4.5)	8.2
	$ (88.7)	$ (280.9)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

As of December 31, 2013, we are holding $16.7 million of cash collateral on our asset exposures, and we have provided letters of credit totaling $76.1 million and $231.2 million relating to our liability exposures pursuant to the margin thresholds in effect at December 31, 2013 and 2012, respectively, under our ISDA® agreements.

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 derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. A reconciliation between the derivative balances presented at gross values rather than the net amounts we present in our other derivative disclosures, is also provided below.

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Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Financial Position	Asset Derivatives Fair Value at December 31,		Liability Derivatives Fair Value at December 31,	
	Location	2013	2012[3]	2013	2012[3]
		(in millions)			
Derivatives designated as hedging instruments[1]					
Interest rate contracts	Other current assets	$ 8.1	$	$	$
Interest rate contracts	Other assets	57.1	2.7		
Interest rate contracts	Accounts payable and other[2]	11.9		(145.5)	(246.9)
Interest rate contracts	Other long-term liabilities		3.3	(11.3)	(68.3)
Commodity contracts	Other current assets	2.0	12.1	(0.6)	(4.2)
Commodity contracts	Other assets	3.5	2.5	(0.5)	(1.0)
Commodity contracts	Accounts payable and other	1.9	4.7	(12.7)	(5.7)
Commodity contracts	Other long-term liabilities	0.6	2.0	(1.4)	(4.5)
		85.1	27.3	(172.0)	(330.6)
Derivatives not designated as hedging instruments					
Interest rate contracts	Other current assets		2.4		(2.2)
Commodity contracts	Other current assets	11.8	27.2	(0.1)	(7.1)
Commodity contracts	Other assets	17.6	11.8	(3.3)	(0.1)
Commodity contracts	Accounts payable and other	5.4	1.6	(16.3)	(10.4)
Commodity contracts	Other long-term liabilities		1.5	(0.2)	(2.3)
		34.8	44.5	(19.9)	(22.1)
Total derivative instruments		$ 119.9	$ 71.8	$ (191.9)	$ (352.7)

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

(2) Liability derivatives exclude $16.7 million of cash collateral at December 31, 2013.

(3) The effect of derivative instruments on the consolidated statements of financial position, as of December 31, 2012, was revised to disclose the financial position location on a gross basis. The revisions to the disclosures are not considered material to and had no impact on amounts previously reported in the consolidated statements of financial position.

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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, 2013					
Interest rate contracts	$ 251.0	Interest expense	$ (29.8)	Interest expense	$ (21.5)
Commodity contracts	(16.5)	Cost of natural gas	2.7	Cost of natural gas	3.3
Total	$ 234.5		$ (27.1)		$ (18.2)
For the year ended December 31, 2012					
Interest rate contracts	$ (45.4)	Interest expense	$ (28.9)	Interest expense	$ (20.5)
Commodity contracts	41.8	Cost of natural gas	0.1	Cost of natural gas	3.1
Total	$ (3.6)		$ (28.8)		$ (17.4)
For the year ended December 31, 2011					
Interest rate contracts	$ (203.3)	Interest expense	$ (27.5)	Interest expense	$ (0.2)
Commodity contracts	17.7	Cost of natural gas	(59.3)	Cost of natural gas	(5.3)
Total	$ (185.6)		$ (86.8)		$ (5.5)

(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, 2012	$ (320.5)
Other Comprehensive Income before reclassifications	216.8
Amounts reclassified from AOCI[1]	27.1
Tax benefit (expense)	
Net other comprehensive income	$ 243.9
Balance at December 31, 2013	$ (76.6)

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

Reclassifications from Accumulated Other Comprehensive Income

	For the year ended December 31,		
	2013	2012	2011
		(in millions)	
Losses (gains) on cash flow hedges:			
Interest Rate Contracts[1]	$ 29.8	$ 28.9	$ 27.5
Commodity Contracts[2]	(2.7)	(0.1)	59.3
Total Reclassifications from AOCI	$ 27.1	$ 28.8	$ 86.8

(1) Loss (gain) reported within Interest expense in the consolidated statements of income.

(2) Loss (gain) reported within Cost of natural gas in the consolidated statements of income.

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Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Earnings[2]	December 31, 2013	2012[6]	2011[6]
		Amount of Gain (Loss) Recognized in Earnings[1] (in millions)		
Interest rate contracts	Interest expense[3]	$	$	$
Commodity contracts	Operating revenue[4]	(6.0)	7.4	11.8
Commodity contracts	Power	0.6	0.1	(0.5)
Commodity contracts	Cost of natural gas[5]	(8.0)	19.5	(26.5)
Total		$ (13.4)	$ 27.0	$ (15.2)

(1) 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.

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

(3) Includes settlement gains of $0.2 million, $0.5 million, and $0.5 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(4) Includes settlement gains of $1.4 million, $6.2 million, and losses of $3.1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(5) Includes settlement losses of $4.6 million, and gains of $21.4 million, and losses of $48.3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(6) The effects of derivative instruments on consolidated statements of income have been revised to include settlement gains on derivatives not designated as hedge instruments of $28.1 and losses of $50.9 million for the years ended December 31, 2012 and 2011, respectively. This revision to the disclosure had no impact on previously reported net income or earnings per unit.

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	December 31, 2013			December 31, 2012		
	Assets	Liabilities[1]	Total	Assets	Liabilities	Total
			(in millions)			
Fair value of derivatives gross presentation	$ 119.9	$ (208.6)	$ (88.7)	$ 71.8	$ (352.7)	$ (280.9)
Effects of netting agreements	(24.3)	24.3		(27.7)	27.7	
Fair value of derivatives net presentation	$ 95.6	$ (184.3)	$ (88.7)	$ 44.1	$ (325.0)	$ (280.9)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

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 net basis by counterparty. 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.

Offsetting of Financial Assets and Derivative Assets

	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	$ 119.9	$ (24.3)	$ 95.6	$ (18.6)	$ 77.0
Total	$ 119.9	$ (24.3)	$ 95.6	$ (18.6)	$ 77.0

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Offsetting of Financial Liabilities and Derivative Liabilities

	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
	(in millions)				
Description:					
Derivatives[1]	$ (208.6)	$ 24.3	$ (184.3)	$ 18.6	$ (165.7)
Total	$ (208.6)	$ 24.3	$ (184.3)	$ 18.6	$ (165.7)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

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, 2013 and 2012. 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, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts[1]	$	$ (96.4)	$	$ (96.4)	$	$ (309.0)	$	$ (309.0)
Commodity contracts:								
Financial		6.4	(6.9)	(0.5)		7.2	8.4	15.6
Physical			(0.2)	(0.2)			6.1	6.1
Commodity options			8.4	8.4			6.4	6.4
Total	$	$ (90.0)	$ 1.3	$ (88.7)	$	$ (301.8)	$ 20.9	$ (280.9)

(1) Includes $16.7 million of cash collateral at December 31, 2013.

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, Crude and Power) 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 change the fair value of the positions.

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Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2013[2] (in millions)		Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
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 Price	86.37	103.04	97.24	Bbl
NGLs	$	(0.1)	Market Approach	Forward NGL Price	0.02	2.19	0.95	Gal
Power	$	(0.7)	Market Approach	Forward Power Price	32.40	38.98	35.07	MWh
Commodity Options								
Natural Gas, Crude and NGLs	$	8.4	Option Model	Option Volatility	18%	44%	28%	
Total Fair Value	$	1.3						

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

(2) Fair values are presented in millions of dollars and include credit valuation adjustments of approximately $0.1 million of gains.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2012[2] (in millions)		Valuation Technique	Unobservable Input	Range[1] Lowest	Highest	Weighted Average	Units
Commodity Contracts Financial								
Natural Gas	$	8.8	Market Approach	Forward Gas Price	3.21	4.31	3.54	MMBtu
NGLs	$	(0.4)	Market Approach	Forward NGL Price	0.25	2.21	1.40	Gal
Commodity Contracts Physical								
Natural Gas	$	1.6	Market Approach	Forward Gas Price	3.19	4.58	3.73	MMBtu
Crude Oil	$	2.6	Market Approach	Forward Crude Price	65.22	116.56	94.31	Bbl
NGLs	$	3.1	Market Approach	Forward NGL Price	0.00	2.22	0.61	Gal
Power	$	(1.2)	Market Approach	Forward Power Price	30.09	36.35	32.74	MWh

Commodity Options								
Natural Gas, Crude and NGLs	$	6.4	Option Model	Option Volatility	29%	104%	40%	
Total Fair Value	$	20.9						

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

(2) Fair values are presented in millions and include credit valuation adjustments of approximately $0.2 million of losses.

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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, 2013 to December 31, 2013. 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, 2013	$ 8.4	$ 6.1	$ 6.4	$ 20.9
Transfers in (out) of Level 3[1]				
Gains or losses				
Included in earnings	(0.8)	22.2	(3.2)	18.2
Included in other comprehensive income	(3.8)			(3.8)
Purchases, issuances, sales and settlements				
Purchases			7.5	7.5
Settlements[2]	(10.7)	(28.5)	(2.3)	(41.5)
Ending balance as of December 31, 2013	$ (6.9)	$ (0.2)	$ 8.4	$ 1.3
Amount of changes in net assets attributable to the change in derivative gains or losses related to assets still held at the reporting date	$ (5.7)	$ (0.3)	$ 7.1	$ 1.1
Amounts reported in operating revenue	$	$ (3.0)	$	$ (3.0)

(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.

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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, 2013 and 2012.

			At December 31, 2013				At December 31, 2012	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	536,870	$ 4.26	$ 4.27	$	$	$	$
	NGL	631,250	$ 69.29	$ 68.99	$ 0.6	$ (0.4)	$	$
Receive fixed/pay variable	Natural Gas	4,478,991	$ 3.94	$ 4.14	$ 0.1	$ (1.0)	$ 0.2	$
	NGL	2,659,300	$ 54.80	$ 57.77	$ 4.8	$ (12.7)	$ 0.9	$ (2.7)
	Crude Oil	1,573,205	$ 94.43	$ 95.67	$ 3.4	$ (5.4)	$ 5.4	$ (2.7)
Receive variable/pay variable	Natural Gas	32,752,500	$ 4.12	$ 4.11	$ 0.6	$ (0.1)	$ 0.1	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,083,450	$ 47.81	$ 47.77	$ 0.9	$ (0.9)	$	$
	Crude Oil	50,700	$ 98.47	$ 98.10	$	$	$	$
Receive fixed/pay variable	NGL	1,335,534	$ 46.80	$ 48.44	$ 0.4	$ (2.6)	$	$
	Crude Oil	165,200	$ 96.08	$ 98.48	$	$ (0.4)	$	$
Receive variable/pay variable	Natural Gas	41,064,012	$ 4.21	$ 4.20	$ 0.9	$ (0.4)	$ 0.5	$
	NGL	9,337,617	$ 40.45	$ 40.23	$ 5.8	$ (3.7)	$	$
	Crude Oil	998,423	$ 97.16	$ 97.33	$ 1.1	$ (1.2)	$	$
Pay fixed	Power[4]	58,608	$ 35.07	$ 46.58	$	$ (0.7)	$	$ (0.8)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	565,750	$ 51.33	$ 50.56	$ 1.5	$ (1.1)	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 88.07	$ 8.3	$	$ 6.8	$ (0.2)
Receive variable/pay variable	Natural Gas	4,707,500	$ 4.02	$ 4.01	$ 0.1	$	$	$
Physical Contracts								
Receive variable/pay variable	Natural Gas	8,802,925	$ 4.19	$ 4.14	$ 0.5	$ (0.1)	$ 0.4	$
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 83.41	$ 0.7	$	$ 0.5	$
Physical Contracts								
Receive variable/pay variable	Natural Gas	996,740	$ 4.23	$ 4.13	$ 0.1	$	$ 0.1	$

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

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

(3) The fair value is determined based on quoted market prices at December 31, 2013 and 2012, 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 $0.1 million of gains and $0.4 million of losses at December 31, 2013 and 2012, respectively.

(4) For physical power, the receive price shown represents the index price used for valuation purposes.

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The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2013 and 2012.

			At December 31, 2013				At December 31, 2012	
			Strike	Market	Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Price(2)	Price(2)	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2014								
Puts (purchased)	Natural Gas	1,825,000	$ 3.90	$ 4.19	$ 0.2	$	$	$
	NGL	493,500	$ 51.91	$ 53.47	$ 2.9	$	$ 1.3	$
Calls (written)	NGL	273,750	$ 57.93	$ 53.35	$	$ (1.0)	$	$
Portion of option contracts maturing in 2015								
Puts (purchased)	Natural Gas	4,015,000	$ 3.90	$ 4.14	$ 1.7	$	$	$
	NGL	930,750	$ 53.57	$ 55.13	$ 6.0	$	$	$
	Crude Oil	273,750	$ 85.00	$ 87.74	$ 1.8	$	$	$
Calls (written)	Natural Gas	1,277,500	$ 5.05	$ 4.14	$	$ (0.3)	$	$
	NGL	109,500	$ 81.90	$ 81.24	$	$ (1.0)	$	$
	Crude Oil	273,750	$ 90.25	$ 87.74	$	$ (1.9)	$	$

(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, 2013 and 2012, respectively, discounted using the swap rate for the respective periods to consider the time value of money.

Fair Value Measurements of Interest Rate Derivatives

We enter into interest rate swaps, caps and derivative financial instruments with similar characteristics to manage the cash flow associated with future interest rate movements on our indebtedness. The following table provides information about our current interest rate derivatives for the specified periods.

				Fair Value(2) December 31,	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate(1)	2013	2012
			(dollars in millions)		
Contracts maturing in 2015					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (6.8)	$ (6.7)
Contracts maturing in 2017					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$ 400	2.21%	$ (13.8)	$ (16.0)
Contracts maturing in 2018					
Interest Rate Swaps Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ 3.3	$ (1.8)
Contracts settling prior to maturity					
2014 Pre-issuance Hedges(3)	Cash Flow Hedge	$ 1,850	4.27%	$ (132.7)	$ (215.4)(4)
2016 Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 60.8	$ 8.4

(1) Interest rate derivative contracts are based on the one-month or three-month London Interbank Offered Rate, or LIBOR.

(2) The fair value is determined from quoted market prices at December 31, 2013 and 2012, 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 $7.1 million of losses at December 31, 2013 and $13.7 million of gains at December 31, 2012

(3) Includes $16.7 million of cash collateral at December 31, 2013.

(4) The December 31, 2012 fair value of pre-issuance hedges due in 2014 has been revised to include a fair value credit of $170.1 million for interest rate hedges originally due in December 2013. These interest rate hedges were amended to extend the maturity date to December 2014 to better reflect the expected timing of future debt issuances.

16. 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 States of Texas and Michigan that are based upon many but not all items included in net income. We report these taxes as income taxes as set forth in the authoritative accounting guidance.

On May 25, 2011, the Governor of Michigan signed legislation implementing a new corporate income tax system. The new tax system became effective January 1, 2012 and repealed the Michigan Business Tax, or MBT, which imposed tax on individuals, LLCs, trusts, partnerships, S corporations, and C corporations and replaces it with the Michigan Corporate Income Tax, or CIT. The CIT only taxes entities classified as C Corporations, therefore, the Partnership is excluded from the CIT and no longer paid Michigan income taxes beginning in 2012.

Our income tax expense is $18.7 million, $8.1 million and $5.5 million for the years ended December 31, 2013, 2012 and 2011, respectively. We computed our income tax expense by applying a Texas state income tax rate to modified gross margin and a Michigan state income tax rate to modified gross receipts. The Texas state income tax rate was 0.5% for the years ended December 31, 2013, 2012 and 2011. The Michigan state income tax rate was 0.2% for the year ended 2011. Our income tax expense represents effective tax rates as applied to pretax book income of 10.4%, 1.6% and 0.9% for December 31, 2013, 2012 and 2011, respectively. The effective tax rate for the Partnership is calculated by dividing the income tax expense by the pretax net book income or loss. The income base for calculating income tax expense is modified gross margin for Texas or modified gross receipts for Michigan rather than net book income or loss.

At December 31, 2013 and 2012, we have included a current income tax payable of $0.9 million and $7.7 million in Property and other taxes payable, respectively. In addition, at December 31, 2013 and December 31, 2012, we have included a deferred income tax liability of $17.4 million and $3.0 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. 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.

For the years ended December 31, 2013, 2012 and 2011, we paid $2.5 million, $7.6 million and $7.4 million in income taxes, respectively.

Furthermore, in June 2013, the Texas Legislature passed House Bill 500 and the tax bill was subsequently signed into law. The most significant change in the law for the Partnership is that House Bill 500, or 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, the Partnership is allowed additional deductions against its income for Texas Margin Tax purposes. We have recorded an additional Deferred income tax liability on our consolidated statements of financial position of approximately $12.4 million for the year ended December 31, 2013 as a result of this new tax law. On a go forward basis, the Partnership s future effective tax rate in the State of Texas will be lower as a result of this law change.

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Accounting for Uncertainty in Income Taxes

The following is a reconciliation of our beginning and ending balance of unrecognized tax benefits in millions:

	(in millions)
Unrecognized tax benefits at December 31, 2012	$ 21.8
Additions for tax positions taken in current period	8.0
Unrecognized tax benefits at December 31, 2013	$ 29.8

As of December 31, 2013 and 2012, the entire balance of unrecognized tax benefits would favorably affect our effective tax rate in future periods if recognized. It is reasonably possible that our liability for unrecognized tax benefits will increase by $2.7 million during the next twelve months. The Company also recognized interest accrued related to unrecognized tax benefits and penalties as income tax expense. As of December 31, 2013, the Company has accrued penalties of $0.5 million and interest of $0.1 million. Furthermore, the Company recognizes accrued interest income related to unrecognized tax benefits in interest income when the related unrecognized tax benefits are recognized. As such, at December 31, 2013 and 2012, $0.6 million and $0.5 million of accrued interest income, respectively, has not been included in the balance of unrecognized tax benefits.

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ended December 2012, 2011, and 2010.

17. OIL MEASUREMENT ADJUSTMENTS

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum operations. The three types of oil measurement adjustments that routinely occur on our systems include:

- Physical, which result from evaporation, shrinkage, differences in measurement (including sediment and water measurement) between receipt and delivery locations and other operational conditions;

- Degradation resulting from mixing at the interface within our pipeline systems or terminal and storage facilities between higher quality light crude oil and lower quality heavy crude oil in pipelines; and

- Revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Quantifying oil measurement adjustments are difficult because: (1) physical measurements of volumes are not practical, as products continuously move through our pipelines, which are primarily located underground; (2) the extensive length of our pipeline systems; and (3) the numerous grades and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our systems and associated oil measurement adjustments. Material changes in our assumptions may result in revisions to our oil measurement estimates in the period determined.

In 2011, we recognized and received $52.2 million for settlement of a dispute with a shipper on our Lakehead crude oil pipeline system. The dispute related to oil measurement adjustments we had previously recognized in prior years and was therefore recorded to Oil measurement adjustments, as a reduction to operating expenses, for the year ended December 31, 2011 in our consolidated statements of income.

18. 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.

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Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

Liquids;

Natural Gas; 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, 2013				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[1]	Total
Total revenue	$ 1,519.9	$ 4,928.8	$ 1,780.6	$	$ 8,229.3
Less: Intersegment revenue		1,061.6	50.6		1,112.2
Operating revenue	1,519.9	3,867.2	1,730.0		7,117.1
Cost of natural gas		3,222.1	1,726.8		4,948.9
Environmental costs, net of recoveries	273.7				273.7
Oil measurement adjustments	(26.7)				(26.7)
Operating and administrative	487.7	444.3	5.5	7.6	945.1
Power	147.7				147.7
Depreciation and amortization	244.9	143.1			388.0
	1,127.3	3,809.5	1,732.3	7.6	6,676.7
Operating income (loss)	392.6	57.7	(2.3)	(7.6)	440.4
Interest expense				320.4	320.4
Allowance for equity used during construction				43.1	43.1
Other income (expense)[3][4]		(1.5)		17.5	16.0
Income (loss) before income tax expense	392.6	56.2	(2.3)	(267.4)	179.1
Income tax expense				18.7	18.7
Net income (loss)	392.6	56.2	(2.3)	(286.1)	160.4
Less: Net income attributable to the Noncontrolling interest				88.3	88.3
Series 1 preferred unit distributions				58.2	58.2
Accretion of discount on Series 1 preferred units				9.2	9.2
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 392.6	$ 56.2	$ (2.3)	$ (441.8)	$ 4.7
Total assets[2]	$ 9,268.9	$ 4,568.4	$ 66.7	$ 997.5	$ 14,901.5
Capital expenditures (excluding acquisitions)	$ 2,330.7	$ 251.3	$	$ 18.8	$ 2,600.8

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Totals assets for our Natural Gas Segment includes our long term equity investment in the Texas Express NGL system.

(3) Other income (expense) for our Natural Gas Segment includes a loss of $1.0 million from our equity investment in the Texas Express NGL system which began recognizing operating costs during the fourth quarter of 2013.

(4) Other income (expense) for our Corporate Segment includes a gain of $17.1 million from the El Dorado storage facility sale in November 2013.

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	As of and for the year ended December 31, 2012 (in millions)				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
Total revenue	$ 1,347.3	$ 4,891.6	$ 1,418.1	$	$ 7,657.0
Less: Intersegment revenue	1.5	923.9	25.5		950.9
Operating revenue	1,345.8	3,967.7	1,392.6		6,706.1
Cost of natural gas		3,172.7	1,397.4		4,570.1
Environmental costs, net of recoveries	(91.3)				(91.3)
Oil measurement adjustments	(11.5)				(11.5)
Operating and administrative	383.0	460.1	6.6	2.3	852.0
Power	148.8				148.8
Depreciation and amortization	210.0	134.8			344.8
	639.0	3,767.6	1,404.0	2.3	5,812.9
Operating income (loss)	706.8	200.1	(11.4)	(2.3)	893.2
Interest expense				345.0	345.0
Allowance for equity used during construction				11.2	11.2
Other expense				(1.2)	(1.2)
Income (loss) before income tax expense	706.8	200.1	(11.4)	(337.3)	558.2
Income tax expense				8.1	8.1
Net income (loss)	706.8	200.1	(11.4)	(345.4)	550.1
Less: Net income attributable to the noncontrolling interest				57.0	57.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 706.8	$ 200.1	$ (11.4)	$ (402.4)	$ 493.1
Total assets[2]	$ 7,361.1	$ 5,162.2	$ 172.6	$ 100.9	$ 12,796.8
Capital expenditures (excluding acquisitions)	$ 1,373.4	$ 439.7	$	$ 13.1	$ 1,826.2

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) Totals assets for our Natural Gas Segment includes our long term equity investment in the Texas Express Pipeline project.

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	As of and for the year ended December 31, 2011				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[1]	Total
Total revenue	$ 1,286.7	$ 7,149.3	$ 2,173.5	$	$ 10,609.5
Less: Intersegment revenue	1.3	1,456.8	41.6		1,499.7
Operating revenue	1,285.4	5,692.5	2,131.9		9,109.8
Cost of natural gas		4,973.8	2,126.3		7,100.1
Environmental costs, net of recoveries	(112.9)	(0.4)			(113.3)
Oil measurement adjustments	(63.4)				(63.4)
Operating and administrative	303.6	392.9	6.3	2.2	705.0
Power	144.8				144.8
Depreciation and amortization	197.1	142.6	0.1		339.8
	469.2	5,508.9	2,132.7	2.2	8,113.0
Operating income (loss)	816.2	183.6	(0.8)	(2.2)	996.8
Interest expense				320.6	320.6
Other income				6.5	6.5
Income (loss) before income tax expense	816.2	183.6	(0.8)	(316.3)	682.7
Income tax expense				5.5	5.5
Net income (loss)	816.2	183.6	(0.8)	(321.8)	677.2
Less: Net income attributable to the noncontrolling interest				53.2	53.2
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 816.2	$ 183.6	$ (0.8)	$ (375.0)	$ 624.0
Total assets[2]	$ 6,157.1	$ 4,680.6	$ 179.4	$ 353.0	$ 11,370.1
Capital expenditures (excluding acquisitions)	$ 654.0	$ 432.8	$	$ 9.8	$ 1,096.6

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) For comparability purposes, we have made reclassifications of approximately $10.7 million out of Total Corporate assets into Total Natural Gas assets for the December 31, 2011 balances. The reclassification represents our long term equity investment in the Texas Express Pipeline project as of December 31, 2011

19. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative regulatory accounting provisions to a number of our pipeline projects that meet the criteria outlined for regulated operations. The rates for the Southern Access, Alberta Clipper and Eastern Access pipelines as well as for our Line 6B 75-mile Replacement Project, which are currently the primary applicable projects, are based on a cost-of-service recovery model that follows the FERC s authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls annually based on forecast volumes and costs. A difference between forecast and actual results causes an under or over collection of revenue in any given year, which is trued-up in the following year. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized the following year. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with the

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FERC and through toll rate adjustments with our customers. The assets and liabilities that we recognize for regulatory purposes are recorded in Other current assets and Accounts payable and other, respectively, on our consolidated statements of financial position.

Southern Access Pipeline

For the year ended December 31, 2013, we had a net under collection of revenue for our Southern Access Pipeline primarily due to our actual volumes being lower than the forecasted volumes used for our April 2013 surcharge filing, partially offset by higher than anticipated power credit adjustments. As a result, for the year ended December 31, 2013, we adjusted our revenues by a net increase of $7.0 million, on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at December 31, 2013. The amounts will be included in our tolls beginning April 2014 when we update our transportation rates.

For the year ended 2012, we had a net under collection of revenue for our Southern Access Pipeline primarily due to favorable power cost adjustments, partially offset by actual volumes being higher than the forecast volumes used to calculate the toll surcharge. As a result, for the year ended 2012, we adjusted our revenues by a net increase of $0.7 million on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at 2012. We recovered these amounts from our customers when we updated our transportation rates to account for the higher than estimated delivered volumes, which became effective in April 2013.

Alberta Clipper Pipeline

For the year ended December 31, 2013, we under collected revenue on our Alberta Clipper Pipeline primarily due to our actual volumes being lower than the forecast volumes used for our April 2013 surcharge filing and our income tax rate and return on equity rate base being higher than anticipated, partially offset by higher than anticipated power credit adjustments. As a result, for the year ended December 31, 2013, we increased our revenues by $7.5 million, on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at December 31, 2013 for the differences in transportation volumes. The amounts will be included in our tolls beginning April 2014 when we update our transportation rates to account for the difference between lower actual delivered and forecasted volumes.

For the year ended 2012, we over collected revenue on our Alberta Clipper Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. As a result, for the year ended December 31, 2012, we reduced our revenues by $16.3 million on our consolidated statements of income with a corresponding increase in the regulatory liability on our consolidated statements of financial position at December 31, 2012 for the differences in transportation volumes. The amounts were refunded through our tolls when we updated our transportation rates to account for the higher delivered volumes, which became effective April 2013.

Eastern Access Projects

For year ended December 31, 2013, we over collected revenue on an expansion component of our Eastern Access Projects primarily due to project delays pushing back the in-service date. As a result, year ended December 31, 2013, we reduced our revenue by $10.6 million, on our consolidated statements of income with a corresponding increase in the regulatory liability on our consolidated statement of financial position at December 31, 2013. The amounts will be refunded thorough our tolls beginning April 2014 when we update our transportation rates.

Lakehead Line 6B 75-Mile Replacement Project

For year ended December 31, 2013, we under collected revenue for our Lakehead Line 6B 75-Mile Replacement Project. As a result, for year ended December 31, 2013, we increased our revenue by $3.8 million, on our consolidated statements of income with a corresponding decrease in the regulatory liability on our consolidated statements of financial position at December 31, 2013. The amounts will be recovered beginning April 2014 when we update our transportation rates.

Other Contractual Obligations

Southern Access Pipeline

We have entered into certain contractual obligations with our customers on the Southern Access Pipeline in which a portion of the revenue earned on volumes above certain predetermined shipment levels, or qualifying volumes, are returned to the shippers through future rate adjustments. We record the liabilities associated with this contractual obligation in Accounts payable and other, on our consolidated statements of financial position. The amortization for this contractual obligation reflects the related transportation rate adjustment in the subsequent year. At December 31, 2013 and December 31, 2012, we had $6.1 million and $12.4 million, respectively, in qualifying volume liabilities related to the Southern Access Pipeline on our statements of financial position.

For the year ended 2012, we also incurred liabilities related to contractual obligations with our customers on the Southern Access Pipeline related to qualifying volumes. As a result, in 2012 we reduced our revenues for the amounts due back to our shippers and recorded a liability for the contractual obligation. We amortize the liability in the following year. For the twelve month periods ended December 31, 2013 and 2012, we increased our revenues by $6.3 million and $2.8 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Alberta Clipper Pipeline

A portion of the rates we charge our customers includes an estimate for annual property taxes. If the estimated property tax we collect from our customers is significantly higher than the actual property tax imposed, we are contractually obligated to refund 50% of the property tax over collection to our customers. At December 31, 2013 and December 31, 2012, we had $6.9 million and $6.0 million, respectively, in property tax over collection liabilities related to our Alberta Clipper Pipeline on our statements of financial position.

For the year ended 2012, we also incurred liabilities related to this contractual obligation on the Alberta Clipper Pipeline. As a result, in 2012, we reduced revenues for the amounts due back to our shippers and recorded a liability for the contractual obligation. We amortized the liability on a straight line basis in the following year. For the twelve month periods ended December 31, 2013 and 2012, we increased our revenues by $6.0 million and $7.3 million, respectively, on our consolidated statements of income with a corresponding amount reducing the contractual obligation on our consolidated statements of financial position.

Regulatory Liability for Southern Lights Pipeline In-Service Delay

In December 2006, as part of the regulatory approval process for its pipeline, Enbridge Pipelines (Southern Lights) L.L.C., or Southern Lights, agreed to the request made by the Canadian Association of Petroleum Producers, referred to as CAPP, to delay the in-service date of its pipeline from January 1, 2010 to July 1, 2010. In exchange for Southern Light s postponement of the in-service date of its pipeline, CAPP agreed to reimburse Southern Lights for any carrying costs incurred during this period as a result of the delayed in-service date. The carrying costs were collected by us through the transportation rates charged on our Lakehead system beginning on April 1, 2010 and passed through to Southern Lights. Beginning in the second quarter 2012, we updated the transportation rates on our Lakehead system and began to reduce the transportation rates we charge the shippers to refund the excess amounts we collected. As of December 31, 2013 we had no regulatory liability in connection with the Southern Lights in-service delay. At December 31, 2012, we had $8.2 million, recorded as a regulatory liability on our consolidated statements of financial position for amounts we over collected in connection with the Southern Lights in-service delay. This amount is not reflected in our revenue.

Allowance for Equity Used During Construction

We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Eastern Access Projects, Alberta Clipper, Line 6B 75-mile Replacement and Mainline Expansion projects, we recorded $43.1 million of AEDC in Property, plant and equipment, net on our consolidated statements of financial position at December 31, 2013, and corresponding $43.1 million of Allowance for equity used during construction in our consolidated statements of income at December 31, 2013. We recorded $11.2 million of AEDC in Property, plant and equipment on our consolidated statements of financial position at December 31, 2012, and corresponding $11.2 million of Allowance for equity used during construction in our consolidated statements of income at December 31, 2012.

FERC Transportation Tariffs

Effective April 1, 2013, we filed our Lakehead system annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2013 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. This tariff rate adjustment filing also included the recovery of costs related to the Flanagan Tank Replacement Project and the Eastern Access Phase 1 Mainline Expansion Project. The Lakehead system utilizes the System Expansion Project II and the Facility Surcharge Mechanism, or FSM, which are components of our Lakehead system s overall rate structure and allows for the recovery of costs for enhancements or modifications as well as certain integrity costs to our Lakehead system.

This tariff filing increased the average transportation rate for crude oil movements from the Canadian border to the Chicago, Illinois area by an average of approximately $0.26 per barrel, to an average of approximately $1.93 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

Effective April 1, 2013, we filed updates to the calculation of the surcharges on the two previously approved expansions, Phase 5 Looping and Phase 6 Mainline, on our North Dakota system. These expansions are cost-of-service based surcharges that are trued up each year to actual costs and volumes and are not subject to the FERC indexing methodology. The filing increased transportation rates for all crude oil movements on our North Dakota system with a destination of Clearbrook, Minnesota by an average of approximately $0.55 per barrel, to an average of approximately $2.06 per barrel.

On May 31, 2013, we filed FERC tariffs with effective dates of July 1, 2013, for our Lakehead, North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by the FERC which incorporated the multiplier of 1.045923, which was issued by the FERC on May 15, 2013, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with 18 C.F.R.342.3 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.05 per barrel to an average of approximately $1.98 per barrel.

Effective April 1, 2012, we filed our annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2012 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. Also included was recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order as discussed in Note 13. *Commitments and Contingencies Line 6B Pipeline Integrity Plan*. The Lakehead system utilizes the Facility Surcharge Mechanism, or FSM, which is a component of our Lakehead system s overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

The tariff rate is applicable to each barrel of crude oil that is delivered on our system on or after the effective date of the tariff. This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.22 per barrel.

Effective July 1, 2012, we filed FERC tariffs for our Lakehead, North Dakota and Ozark systems. We increased the rates in compliance with the indexed rate ceilings allowed by FERC which incorporates the multiplier of 1.086011, which was issued by FERC on May 15, 2012, in Docket No. RM93-11-000. The tariff filings are in part index filings in accordance with FERC filing 18 C.F.R.3423 and in part compliance filing with certain settlement agreements, which are not subject to FERC indexing. As an example, we increased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by approximately $0.07 per barrel.

The April 1, 2012 and July 1, 2012 tariff changes decreased the average transportation rate for crude oil movements on our Lakehead system from the Canadian border to Chicago, Illinois by $0.15 per barrel, to an average of approximately $1.67 per barrel.

20. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for the item labeled Other in the Net cash provided by operating activities section our consolidated statements of cash flows.

	For the year ended December 31,		
	2013	2012	2011
	(in millions)		
Gain on sale of assets	$ (17.1)	$	$ (1.5)
Texas Express Long-term Inventory (line fill)	(9.5)		
Impairment of Marshall homes	3.0		
Amortization of debt issuance and hedging costs	10.5	12.7	19.2
Loss on sale of assets	1.1		
Equity loss from investment in Texas Express NGL system	1.0		
Discount accretion	0.7	0.6	0.7
Allowance for interest used during construction		(4.5)	
Allowance for doubtful accounts	(0.4)	0.2	0.6
Write-down of project costs		4.3	
Other	0.2	0.8	2.6
	$ (10.5)	$ 14.1	$ 21.6

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,		
	2013	2012	2011
	(in millions)		
Additions to property, plant and equipment	$ 2,409.9	$ 1,739.9	$ 1,045.2
Increase (decrease) in construction payables	190.9	86.3	51.4
Total capital expenditures (excluding Investment in joint venture)	$ 2,600.8	$ 1,826.2	$ 1,096.6

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21. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Obligations Resulting from Joint and Several Liability Arrangements

In February 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-04 which provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Presentation of Unrecognized Tax Benefits

In July 2013, Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2013-11 which requires the presentation of unrecognized tax benefit as a reduction to a deferred tax asset for a net operating loss carry forward unless specific conditions exist. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied prospectively. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

22. QUARTERLY FINANCIAL DATA (Unaudited)

	First	Second [1]	Third[1]	Fourth[1]	Total
		(in millions, except per unit amounts)			
2013 Quarters					
Operating revenue	$ 1,693.0	$ 1,672.7	$ 1,789.4	$ 1,962.0	$ 7,117.1
Operating expense	$ 1,690.6	$ 1,463.7	$ 1,665.8	$ 1,856.6	$ 6,676.7
Operating income	$ 2.4	$ 209.0	$ 123.6	$ 105.4	$ 440.4
Net income	$ (67.7)	$ 123.7	$ 61.3	$ 43.1	$ 160.4
Net income attributable to noncontrolling interest	$ 15.6	$ 18.4	$ 20.3	$ 34.0	$ 88.3
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (83.3)	$ 89.9	$ 14.9	$ (16.8)	$ 4.7
Net income per limited partner unit	$ (0.36)	$ 0.18	$ (0.05)	$ (0.15)	$ (0.39)
2012 Quarters					
Operating revenue	$ 1,819.5	$ 1,551.1	$ 1,564.3	$ 1,771.2	$ 6,706.1
Operating expense	$ 1,621.8	$ 1,327.6	$ 1,253.8	$ 1,609.7	$ 5,812.9
Operating income	$ 197.7	$ 223.5	$ 310.5	$ 161.5	$ 893.2
Net income	$ 112.0	$ 139.7	$ 229.2	$ 69.2	$ 550.1
Net income attributable to noncontrolling interest	$ 13.0	$ 15.1	$ 14.0	$ 14.9	$ 57.0
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 99.0	$ 124.6	$ 215.2	$ 54.3	$ 493.1
Net income per limited partner unit	$ 0.25	$ 0.33	$ 0.60	$ 0.07	$ 1.27

(1) In 2012, we recognized $20.0 million, $25.0 million, and $10.0 million of additional costs during the second, third, and fourth quarters, respectively, related to the crude oil release on Line 6B. In 2012, we also recognized $170.0 million of environmental insurance recoveries during the third quarter, related to the crude oil release on Line 6B.

23. SUBSEQUENT EVENTS

Distribution to Partners

On January 30, 2014, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2014. The distribution was paid to unitholders of record as of February 7, 2014, of our available cash of $213.7 million at December 31, 2013, or $0.54350 per limited partner unit. Of this distribution,

$178.4 million was paid in cash, $34.6 million was distributed in i-units to our i-unitholder and $0.7 million was retained from our General Partner in respect of the i-unit distribution to maintain its 2% general partner interest.

Distribution to Series AC Interests

On January 30, 2014, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP paid $12.8 million to the noncontrolling interest in the Series AC, while $6.4 million was paid to us.

Distribution to MEP Partners

On January 29, 2014, the board of directors of Midcoast Holdings, L.L.C., acting in its capacity as the general partner of MEP, declared a cash distribution payable of $0.16644 per unit for the quarter ended December 31, 2013. The distribution was paid on February 14, 2014 to unitholders of record on February 7, 2014. This amount represents the prorated minimum quarterly distribution of $0.31250 per unit, or $1.25 on an annualized basis, for the period from the completion of the Offering through December 31, 2013. MEP paid $3.5 million to its public Class A common unitholders, while $4.2 million in the aggregate was paid to EEP with respect to its Class A common units, subordinated units and general partner interest.

Credit Facilities

On February 3, 2014, EEP entered into an uncommitted letter of credit arrangement, pursuant to which the bank may, on a discretionary basis and with no commitment, agree to issue standby letters of credit upon our request in an aggregate amount not to exceed $200.0 million. While the letter of credit arrangement is uncommitted and issuance of letters of credit is at the bank s sole discretion, we view this arrangement as liquidity enhancement as it allows EEP to potentially reduce its reliance on utilizing the committed Credit Facilities for issuance of letters of credit to support its hedging activities.

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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 Securities and Exchange Commission, 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, 2013. 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.

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Management assessed the effectiveness of the Partnership s internal control over financial reporting as of December 31, 2013, with the participation of our principal executive and principal financial officers, based on the framework established in *Internal Control Integrated Framework (1992)* 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, 2013.

The effectiveness of the Partnership s internal control over financial reporting as of December 31, 2013 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, 2013.

Item 9B. Other Information

On February 11, 2014, C. Gregory Harper entered into an employment agreement with Enbridge Employee Services, Inc. (EES), an affiliate of our General Partner. The agreement terminates upon retirement, death, disability or other termination of employment. The agreement provides that EES will pay severance benefits to Mr. Harper if his employment is terminated involuntarily without cause or because of the disability of Mr. Harper, or if his employment is terminated voluntarily for good reason. The benefits include (i) a retiring allowance of two times the sum of his annual salary and the average of the last two annual incentive bonuses paid to Mr. Harper; (ii) an annual incentive bonus for the calendar year in which termination occurs; accrued and unpaid vacation payout; payout under any incentive plans on a pro-rata basis, as provided by such plan; an amount equivalent to EES s portion of 401(k) plan contributions (as provided by such plan) for two years; reimbursement of certain amounts of career counseling within one year following termination and the cash value of two times the last annual flexible perquisite allowance immediately preceding the termination date (less any amounts prepaid, but unearned as of the termination date); (iii) to the extent he has a vested benefit in any defined benefit plan or supplemental benefit pension plan, he will receive a related payout amount as provided in the agreement; (iv) the ability to exercise any vested and exercisable stock options he holds under EES s or affiliate s stock option plans in accordance with the terms of such plans and any related agreements; (v) with respect to unvested options, the cash value of the excess of the fair market value of the shares (or other applicable securities) on the termination date divided by the exercise price for such options. Mr. Harper will be required to sign a release agreement in exchange for such benefits.

The agreement also provides that Mr. Harper will maintain the confidential information of EES and its affiliates and will not solicit business for one year following termination in competition with EES and its affiliates from EES s or its affiliates partners, customers or prospective partners or customers (as of the termination date) or any person with whom they have a business relationship within one year preceding the termination date. The agreement also provides for a post-termination two year restriction on recruitment of EES and affiliate employees.

The foregoing summary of the agreement is qualified in its entirety by the full terms and conditions of the agreement, a copy of which is filed as Exhibit 10.31 hereto and is incorporated herein by reference.

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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 the General Partner and of Enbridge Management as the delegate of the General Partner under a delegation of control agreement among us, the General Partner and Enbridge Management. All directors of the General Partner are elected annually and may be removed by Enbridge Pipelines, as the sole shareholder of the General Partner, an indirect and wholly-owned subsidiary of Enbridge. All directors of Enbridge Management were elected and may be removed by the General Partner, as the sole holder of Enbridge Management s voting shares. All officers of the General Partner and Enbridge Management serve at the discretion of the boards of directors of the General Partner and Enbridge Management, respectively. All directors and officers of the General Partner hold identical positions in Enbridge Management.

Name	Age	Position
Jeffrey A. Connelly	67	Director and Chairman of the Board
J. Herbert England	67	Director
Rebecca B. Roberts	61	Director
Dan A. Westbrook	61	Director
J. Richard Bird	64	Director
C. Gregory Harper	49	Director
Mark A. Maki	49	President and Principal Executive Officer and Director
Terrance L. McGill	59	Senior Vice President and Director
Stephen J. Wuori	56	Executive Vice President Liquids Pipelines and Director
Leon A. Zupan	58	Executive Vice President and Former Director
Richard L. Adams	49	Senior Vice President
Stephen J. Neyland	46	Vice President Finance
Janet L. Coy	56	Vice President Natural Gas Marketing
Noor S. Kaissi	41	Controller
E. Chris Kaitson	57	Vice President Law and Assistant Secretary
John A. Loiacono	51	Vice President Commercial Activities
Byron C. Neiles	48	Senior Vice President Major Projects
Kerry C. Puckett	52	Vice President Engineering and Operations, Gathering & Processing
Allan M. Schneider	55	Vice President Regulated Engineering and Operations
Bradley F. Shamla	45	Vice President U.S. Operations, Liquids Pipelines
Darren Yaworsky	43	Treasurer

DIRECTORS AND NAMED EXECUTIVE OFFICERS

Jeffrey A. Connelly

Jeffrey A. Connelly was elected as Chairman of the Board of Directors, or the Board, in July 2012 and as a director of the General Partner and Enbridge Management in January 2003. Previously, Mr. Connelly served as Chairman of the Audit, Finance & Risk Committee of the General Partner and Enbridge Management. Mr. Connelly also served as Executive Vice President, Senior Vice President and Vice President of the Coastal Corporation from 1988 to 2001.

Mr. Connelly brings significant financial experience to our Board because of his experience as the former Treasurer and other executive roles with Coastal Corporation, a former Fortune 500 Company whose principal business segments included gathering, processing, transmission, storage and distribution of natural gas; oil refining and marketing; oil exploration and production; electric power production; and coal mining. He also served as the chief executive officer for several wholly-owned Coastal subsidiaries.

J. Herbert England

J. Herbert England was elected a director of the General Partner and Enbridge Management in July 2010 and was appointed as the Chairman of the Audit, Finance & Risk Committee of the General Partner and Enbridge Management in July 2012. Mr. England also serves on the Enbridge board of directors and the board of directors of FuelCell Energy, Inc. and in 2013, he was appointed to the board of directors of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P., for whom he also serves as Chairman of the Audit, Finance and Risk Committee. 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 a wide range of financial executive experience because of his previous positions, as well as his service with other public company audit committees.

Rebecca B. Roberts

Rebecca B. Roberts was elected a director of the General Partner and Enbridge Management in July 2012 and serves on the Audit, Finance & Risk Committee of the General Partner and Enbridge Management. Ms. Roberts currently serves on the board of directors of Mine Safety Appliances Company, a safety equipment manufacturer and of Black Hills Corporation, a diversified energy company whose non-regulated businesses generates wholesale electricity and produce natural gas, oil and coal and whose utilities businesses serve natural gas and electric customers. From 2006 to 2011, Ms. Roberts was President of Chevron Pipe Line Company. Prior to that, she was President of Chevron Global Power Generation from 2003 to 2006. Ms. Roberts held various other positions within Chevron and its subsidiaries from 1974 to 2003. She also served on the board of Dynegy Energy Company and Dynegy Holdings Inc. from 2006 to 2007.

Ms. Roberts brings to the Board considerable pipeline and energy industry experience because of her service with other companies in the energy sector.

Dan A. Westbrook

Dan A. Westbrook was elected a director of the General Partner and Enbridge Management in October 2007 and serves on the Audit, Finance & Risk Committee of the General Partner and Enbridge Management, as well as 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. and a director and chairman of the board of Midcoast Holdings, L.L.C., the general partner of Midcoast Energy, L.P., and serves on their Audit Finance and Risk Committee. 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 as 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 our Board with extensive industry experience, leadership skills, international and petroleum development experience, as well as knowledge of our business environment.

J. Richard Bird

J. Richard Bird was elected a director of the General Partner and for Enbridge Management in October 2012. Mr. Bird also currently serves as Executive Vice President, Chief Financial Officer and Corporate Development for Enbridge. Since 1995, when he joined Enbridge as Vice President and Treasurer, Mr. Bird has held various managerial positions with Enbridge, including Executive Vice President Liquids Pipelines and Senior Vice President Corporate Planning and Development. Mr. Bird also served as president of the General Partner from July 2000 to June 2001 and from 2003 to 2008 he held several positions with the General Partner and Enbridge Management, including Director and Vice President and Executive Vice President Liquids Pipelines, and Group Vice President Liquids Transportation. Prior to joining Enbridge, Mr. Bird held senior financial executive positions at a number of other public companies.

Through his long career in the energy industry and his financial expertise, Mr. Bird provides significant experience to the Boards of the General Partner and Enbridge Management.

C. Gregory Harper

C. Gregory Harper was appointed to the board of directors of the General Partner and the board of directors of Enbridge Management on January 30, 2014. Mr. Harper was also appointed to the board of directors of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. on January 30, 2014. Mr. Harper also was appointed as President, Gas Pipelines and Processing for Enbridge effective January 30, 2014. He has also served on the board of directors of Sprague Operating Resources LLC since October 2013. Prior to joining Enbridge, Mr. Harper served as the Senior Vice President, Midstream for Southwestern Energy 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 was Group Vice President of Spectra Energy Corp., and he was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper served as 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 for 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.

Mark A. Maki

Mark A. Maki was appointed President and Principal Executive Officer of the General Partner and Enbridge Management on January 30, 2014 and has served as a director of both companies since October 2010. Mr. Maki is also a director and Principal Executive Officer of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. Previously, Mr. Maki served as President of Enbridge Management and Senior Vice President of the General Partner from October 2010 and he served Enbridge in the functional title of Acting

President, Gas Pipelines during 2013. Mr. Maki previously served as Vice President Finance of the General Partner and Enbridge Management from July 2002. Prior to that time, Mr. Maki served as Controller of the General Partner and Enbridge Management from June 2001, and prior to that, as Controller of Enbridge Pipelines from September 1999.

Mr. Maki progressed through a series of accounting and financial roles of increasing responsibility during his 27 years with Enbridge in the United States and Canada. Through his broad range of domestic and Canadian experience in the pipeline industry, Mr. Maki provides our Board with financial expertise, leadership skills in our industry and knowledge of our local community and business environment.

Terrance L. McGill

Terrance L. McGill has served as a director of the General Partner and Enbridge Management since May 2006, Senior Vice President of Enbridge Management since October 2010 and as Senior Vice President of the General Partner since January 30, 2014. Mr. McGill is also a director and President of Midcoast Holdings, L.L.C., the general partner of Midcoast Energy Partners, L.P. Previously Mr. McGill served as President of the General Partner from October 2010 through January 2014. From May 2006 to October 2010, Mr. McGill served as President of the General Partner and of Enbridge Management. Prior to that, Mr. McGill served as Vice President Commercial Activity and Business Development of the General Partner and Enbridge Management from April 2002 and Chief Operating Officer from July 2004. Prior to that time, Mr. McGill was President of Columbia Gulf Transmission Company from January 1996 to March 2002.

Mr. McGill gives our Board insight and in-depth knowledge of our industry and our specific operations and strategies. 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.

Stephen J. Wuori

Stephen J. Wuori was elected a director of the General Partner and Enbridge Management and has served as the Executive Vice President Liquids Pipelines since January 2008. Mr. Wuori also has served Enbridge as President, Liquids Pipelines and Major Projects since January 2012, prior to which he held the title of President, Liquids Pipelines of Enbridge since October 2010. From 2008 to October 2010, Mr. Wuori served Enbridge as Executive Vice President Liquids Pipelines. He was previously appointed Executive Vice President, Chief Financial Officer and Corporate Development of Enbridge from 2006 to 2008, Group Vice President and Chief Financial Officer of Enbridge from 2003 to 2006 and Group Vice President, Corporate Planning and Development of Enbridge from 2001 to 2003.

As Executive Vice President Liquids Pipelines, Mr. Wuori provides our Board insight and in-depth knowledge of our industry and our specific operations and strategies. He also provides financial expertise, leadership skills, pipeline operations expertise and knowledge of our business environment, which he has gained through his long career with Enbridge.

Leon A. Zupan

Leon A. Zupan currently serves the General Partner and Enbridge Management as Executive Vice President since April 2013. In April 2013, he resigned as a director and as Executive Vice President Gas Pipelines of the General Partner and Enbridge Management, positions which he had held since April 2012, to accept a new position with Enbridge as Chief Operating Officer. Prior to April 2012, he had served the General Partner and Enbridge Management as Vice President Operations since 2004. He had served Enbridge as Senior Vice

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President Gas Pipelines, overseeing Enbridge s U.S. and Canadian gas pipelines businesses, from February 2012 to April 2013. Prior to that, Mr. Zupan had served Enbridge as Vice President Operations since 2004. He has more than 26 years experience with Enbridge across a range of businesses.

Richard L. Adams

Richard L. Adams was elected Senior Vice President of the General Partner and Enbridge Management in April 2013. In May 2013, he was named Senior Vice President, Operations of Enbridge. Previously Mr. Adams was Vice President U.S. Operations, Liquids Pipelines of the General Partner and Enbridge Management from February 2010. Prior positions Mr. Adams held with the General Partner and Enbridge Management are Vice President U.S. Engineering and Project Execution, Liquids Pipelines from June 2007, Vice President Operations and Technologies from April 2003, Director of Technology & Operations from 2001. He was Director of Field Operations and Technical Services and Director of Commercial Activities for OCENSA/Enbridge in Bogota, Colombia from 1997 to 2001.

Stephen J. Neyland

Stephen J. Neyland was appointed Vice President Finance of the General Partner and Enbridge Management in October 2010. Mr. Neyland also serves as Vice President Finance of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. Mr. Neyland was previously Controller of the 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.

OTHER EXECUTIVE OFFICERS

Janet L. Coy was appointed Vice President Natural Gas Marketing of the General Partner and Enbridge Management in October 2010. Ms. Coy also serves as Vice President Natural Gas Marketing of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. Ms. Coy previously served as President of the Natural Gas Marketing subsidiaries of Enbridge Management and the General Partner since the acquisition of Midcoast Energy Resources, Inc. and continues to serve in that capacity.

Noor S. Kaissi was appointed Controller of the General Partner and Enbridge Management in July 2013. Ms. Kaissi also serves as Controller of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. Ms. Kaissi previously served as Chief Auditor and in other managerial roles of the General Partner with responsibility for financial accounting, internal audit and controls from June 2005.

E. Chris Kaitson was appointed Vice President Law of the General Partner and Enbridge Management in May 2007. Mr. Kaitson also serves as Vice President Law and Assistant Secretary of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. He also currently serves as Deputy General Counsel of Enbridge. Prior to that, he was Assistant General Counsel and Assistant Secretary of the General Partner and Enbridge Management from July 2004. He served as Corporate Secretary of the 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.

John A. Loiacono was appointed Vice President Commercial Activities, of the General Partner and Enbridge Management in July 2006. Mr. Loiacono also serves as Vice President Commercial Activities of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. Prior to that, he was Director of Commercial Activities for the 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.

Byron C. Neiles was appointed Senior Vice President Major Projects of the General Partner and Enbridge Management in April 2013. He also serves as Vice President Major Projects of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. He 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. Mr. Neiles was Vice President Major Projects of the General Partner and Enbridge Management from October 2010 until his current appointment. Mr. Neiles joined Enbridge in 1994 and has served in various positions with Enbridge, including Vice President of Enbridge Gas Distribution from 2003 to 2008.

Kerry C. Puckett was appointed Vice President Engineering and Operations, Gathering & Processing of the General Partner and Enbridge Management in October 2007. Mr. Puckett also serves as Vice President Engineering and Operations, Gathering & Processing of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. 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.

Allan M. Schneider was appointed Vice President Regulated Engineering and Operations of the General Partner and Enbridge Management in October 2007. Mr. Schneider also serves as Vice President Regulated Engineering and Operations of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. 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.

Bradley F. Shamla was appointed Vice President U.S. Operations, Liquids Pipelines of the General Partner and Enbridge Management in April 2013. He previously served Enbridge as Vice President, Market Development since October 2010. Mr. Shamla was previously a senior director in the Business Development Group of Enbridge since 2008 and before that he was general manager in the LP Operations Group, having joined Enbridge in 1991 and working in a number of areas, including Operations, Engineering and Administration, both in the U.S. and Canada.

Darren J. Yaworsky was appointed Treasurer of the General Partner and Enbridge Management in October 2012. Mr. Yaworsky also serves as Treasurer of Midcoast Holdings, L.L.C., general partner of Midcoast Energy Partners, L.P. He is also Director Treasury, for Enbridge, a position he has held since 2011. Mr. Yaworsky has held the following positions since joining Enbridge in 2008: From 2010 to 2011, he served as Senior Manager Treasury and from 2008 to 2010 he was Manager Treasury. Prior to joining Enbridge, Mr. Yaworsky was Managing Director with Bank of Montreal from 2005 to 2008 and has worked in the banking industry since 1998.

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 inquiries made to our directors and executive officers, we believe that all filings required to be made under Section 16(a) during 2013 and prior years were timely made, with the exception of Janet Coy who failed to file reports relating to an aggregate of 77.647 Class A common units acquired in 8 purchases made quarterly between February 2012 and November 2013 pursuant to a dividend reinvestment program conducted by the broker holding her shares.

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GOVERNANCE MATTERS

We are a controlled company, as that term is used in NYSE Rule 303A, because all of our voting shares are owned by the General Partner. Because we are a controlled company, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the 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 March 21, 2013.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

We have adopted a Code of Ethics applicable to our senior officers, including the principal executive officer, principal financial officer and principal accounting officer of Enbridge Management. A copy of the Code of Ethics for Senior Financial Officers is available on our website at *www.enbridgepartners.com* and is included herein as Exhibit 14.1. 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 Enbridge 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.enbridgepartners.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 Enbridge 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.enbridgepartners.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 Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

AUDIT, FINANCE & RISK COMMITTEE

Enbridge Management 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 Jeffrey A. Connelly, J. Herbert England, Dan A. Westbrook and Rebecca B. Roberts. 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.

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The charter of the Audit Committee is available on our website at *www.enbridgepartners.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 Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Enbridge Management s Board of Directors has determined that J. Herbert England and Jeffrey A. Connelly 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 Enbridge Management, FuelCell Energy, Inc., Midcoast Holdings, L.L.C. 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 of Midcoast Holdings, L.L.C. determined that Mr. England s simultaneous service on such audit committees does not impair his ability to effectively serve on the Audit Committee.

Enbridge Management 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 Enbridge Energy Management, L.L.C., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of Enbridge Management meet at regularly scheduled executive sessions without management. Jeffrey A. Connelly 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, Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

General

We are a master limited partnership and do not employ directly any employees nor do we have executive officers or directors. We are managed by Enbridge Management, a delegate of our General Partner, and the Named Executive Officers, or NEOs, are executive officers of Enbridge Management and our General Partner. Similarly, the directors are members of the boards of directors of Enbridge Management and our General Partner. Our General Partner and Enbridge Management are indirect subsidiaries of Enbridge, and we are a business unit of Enbridge. Our General Partner, Enbridge Management and Enbridge, through its affiliates, provide us with managerial, administrative, operational and director services pursuant to service agreements among them and us. Pursuant to these service agreements, we reimburse our General Partner, Enbridge Management and affiliates of Enbridge for the costs of these managerial, administrative, operational and director services, which costs include a portion of the compensation of the NEOs.

The boards of directors of Enbridge Management and our General Partner do not have compensation committees, nor do they have responsibility for approving the elements of compensation for the NEOs presented in the tables following this discussion. The boards of directors of Enbridge Management and our General Partner, as part of our annual budgeting process, however, do have responsibility for evaluating and determining the

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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, Enbridge Management and Enbridge and its affiliates pursuant to the service agreements 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 and Enbridge Management do not have responsibility for approving the elements of compensation for the NEOs, we, our General Partner and Enbridge Management 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, 2013 were:

Mark A. Maki, President of Enbridge Management, Senior Vice President of the General Partner and Director

Terrance L. McGill, President of the General Partner, Senior Vice President of Enbridge Management and Director

Stephen J. Neyland, Vice President Finance

Stephen J. Wuori, Executive Vice President Liquids Pipelines and Director

Leon A. Zupan, Executive Vice President

Richard L. Adams, Senior Vice President

Messrs. Wuori and Zupan are also executive officers of Enbridge and Enbridge Pipelines, respectively. Mr. Wuori serves as President, Liquids Pipelines & Major Projects of Enbridge and Mr. Zupan serves as Chief Operating Officer, Liquids Pipelines of Enbridge Pipelines. Since Messrs. Wuori and Zupan are also executive officers of Enbridge and Enbridge Pipelines, respectively, the Human Resources and Compensation Committee of the board of directors of Enbridge, or the HRC Committee, approves the elements of compensation for them based on the recommendation of the President & Chief Executive Officer of Enbridge considering his position within Enbridge on an enterprise-wide basis.

The HRC Committee does not have responsibility for reviewing or approving compensation for employees, on an individual basis, who are not a part of Enbridge s executive leadership team. 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 HRC Committee for approval. Individual salary increases are implemented after the HRC Committee approves the overall budget. Compensation adjustments for senior leadership of the various business units are recommended by their supervisors and reviewed by the executive leadership team of Enbridge. The Enbridge executive leadership team and the President & Chief Executive Officer of Enbridge review the elements of compensation for all our NEOs. 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, his compensation is determined on the basis of his overall performance with respect to Enbridge and all of its affiliates and not solely based on his 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.

In 2013, the board of directors of Enbridge implemented an Incentive Compensation Clawback Policy that will enable 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 Enbridge board of directors. As a business unit of Enbridge, we contribute to its overall growth, earnings and attainment of performance goals. The following table presents our historical adjusted earnings, which excludes the impact of non-recurring and non-operating items, as a percentage of the adjusted earnings of Enbridge for the preceding five years:

2013	2012	2011	2010	2009
14%	14%	17%	17%	12%

The elements of total compensation in 2013 for senior management of Enbridge, which include Messrs. Wuori and Zupan, 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-based 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, performance-based compensation comprised of performance stock units, performance-based stock options and incentive stock options that are tied to the share price of Enbridge common shares, and are mostly 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 change of control.

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The elements of compensation for Messrs. Maki, McGill, Neyland and Adams are similar to those described above, except that none have an employment agreement, and they are not eligible for performance-based stock options. The HRC Committee makes determinations as to whether the enterprise-wide performance goals have been achieved, approves business unit results and if adjustments are 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 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. Enbridge corporate performance is a factor in determining incentive awards.

The following is a summary for 2013 of the incentive targets, payout range, and relative weightings between the Enbridge corporate, business unit and individual performance:

	Target STIP%[1]	Pay Out Range	Relative Weighting Corporate	Business Unit	Individual
Mark A. Maki *President of Enbridge Management, Senior Vice President of the General Partner and Director*	40%	0-80%	25%	50%	25%
Terrance L. McGill *President of the General Partner, Senior Vice President of Enbridge Management and Director*	40%	0-80%	25%	50%	25%
Stephen J. Neyland *Vice President Finance*	35%	0-70%	25%	50%	25%
Stephen J. Wuori *Executive Vice President Liquids Pipelines and Director*	65%	0-130%	25%	50%	25%
Leon A. Zupan[2] *Executive Vice President and Director*	60%	0-120%	25%	50%	25%
Richard L. Adams *Senior Vice President, Operations*	40%	0-80%	25%	50%	25%

(1) All values are expressed as percentages of base salary.

(2) Effective January 1, 2013, Mr. Zupan s STIP target increased from 50% to 60% as a result of a compensation benchmarking review conducted by Mercer in November 2012, to maintain his competitive market positioning.

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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.

The adjusted EPS metric represents a significant component of the named executives short-term incentive award at 25%. Enbridge s 2013 EPS guidance range was $1.74 CAD $1.90 CAD as approved by the Enbridge Board prior to the start of 2013. Actual performance was $1.78 CAD. Adjustments are made to ensure the result is a fair reflection of performance. Approximately $988 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.

During 2013, Enbridge management undertook, with Enbridge Board approval, a supplementary financing plan that included common equity and preferred equity pre-funding actions that were not provided for in the original budget, prompted by significant expansions to the company s five-year growth capital plan, which emerged over the course of the year. Although these actions had an adverse impact on Enbridge s 2013 EPS, they were necessary and prudent steps to support the medium and long-term objectives of Enbridge. At the same time, an unanticipated change in the account methodology applicable to three of Enbridge s contract pipelines, resulted in a small, but positive variance to 2013 budgeted EPS generated by these assets. The HRC Committee approved an adjustment to the calculated EPS result utilized for the corporate performance multiplier for short-term incentive purposes only, to better align the short-incentive awards for employees with the positive near-term and long-term outcomes for shareholders and Enbridge. Adjusting out the negative impact of the specific pre-funding actions and the positive impact of the change in accounting methodology noted above, resulted in an adjusted EPS of $1.815 CAD (versus $1.78 CAD per share) and a short-term corporate multiplier of 0.94 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. Mr. Maki s performance measure is calculated at 56% for the Gas Transportation business unit, 27% for the Gas Development business unit and 17% for the Shared Services business unit, resulting in a business unit multiplier of 1.17 out of 2.0. Mr. McGill s performance measure is calculated at 75% for the Gas Transportation business unit and 25% for the Gas Development business unit, resulting in a business unit multiplier of 1.18 out of 2.0. Mr. Neyland s performance measure is calculated at 100% for the Shared Services business unit, resulting in a business unit multiplier of 1.05 out of 2.0. Mr. Adams s performance measure is calculated at 100% for the Liquids business unit resulting in a business unit multiplier of 1.17 out of 2.0.

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Mr. Zupan s performance measure is calculated at 67% for the Liquids business unit, 20% for the Gas Transportation business unit and 13% for the Gas Development business unit, resulting in a business unit multiplier of 1.18 out of 2.0. Mr. Wuori s performance measure is calculated at 80% for the Liquids business unit and 20% for the Major Projects business unit, resulting in a business unit multiplier of 1.22 out of 2.0.

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 the Partnership, but also include portions of other Enbridge businesses.

Gas Transportation

Performance Measure	**Weight**	**Sub Measures & Weightings**		**Rating**	**Performance Multiplier**
Safety	20%	Health & Safety Training	6%	1.08	0.21
		Safety Observations	6%		
		Total Recordable Injury Frequency	4%		
		Contributory Motor Vehicle Accidents	4%		
Operations & Integrity	25%	Integrity Management & Process Safety	25%	1.56	0.39
Financial	40%	Budgeted Earnings	40%	0.60	0.24
Employee Engagement &	15%	Healthy Workforce Initiative	5%	1.91	0.29
Compliance		Employee Development	5%		
		SOX Compliance	5%		
		Business Unit Performance Multiplier			**1.13**

Gas Development

Performance Measure	**Weight**	**Sub Measures & Weightings**		**Rating**	**Performance Multiplier**
Operations, Safety & Integrity	25%	Asset Transition and Risk Reduction Management Plan	11%	1.25	0.31
		Safety Observations	6%		
		Total Recordable Injury Frequency	4%		
		Contributory Motor Vehicle Incidents	4%		
Financial	40%	Budget Earnings	40%	1.11	0.44
Business Development	35%	Contracting Strategies & New Investments	35%	1.64	0.58
		Business Unit Performance Multiplier			**1.33**

Shared Services

Performance Measure	Weight	Sub Measures & Weightings		Rating	Performance Multiplier
Safety	20%	Health & Safety Training	6%	1.08	0.21
		Safety Observations	6%		
		Total Recordable Injury Frequency	4%		
		Contributory Motor Vehicle Incidents	4%		
Operations & Integrity	25%	Integrity Management & Process Safety	25%	1.56	0.39
Financial	40%	Budgeted Earnings	40%	0.40	0.16
Employee Engagement & Compliance	15%	Healthy Workforce Initiative	5%	1.91	0.29
		Employee Development	5%		
		Sox Compliance	5%		
		Business Unit Performance multiplier			**1.05**

Liquids Pipelines

Performance Measure	Weight	Sub Measure % Weightings		Rating	Performance Multiplier
Leadership in Safety and Operations	40%	Safety Observations & Training	9%	1.3	0.52
		Total Recordable Injury Frequency	4%		
		Motor Vehicle Incidents	2%		
		Significant Off-Property Releases	10%		
		Leak Detection	5%		
		System Inspection Program	5%		
		Governance, Compliance & Ethics	5%		
Maximize Financial Performance	40%	Budgeted Earnings	40%	0.2	0.08
Outstanding People	5%	Overall Employee Retention	5%	2.0	0.10
Superior Customer Experience	5%	System Capacity Optimization	4%	1.4	0.07
		Product Quality	1%		
Business Growth	10%	Enbridge Liquids Pipelines Growth Opportunities	10%	2.0	0.20
		Business Unit Performance multiplier			0.97
		Management Adjustment[(1)]			0.20
		Business Unit Performance Multiplier			**1.17**

(1) An adjustment was approved at management s discretion.

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Major Projects

Performance Measure	Weight	Sub Measures & Weightings	Rating	Performance Multiplier
Safety	15%	Leading and lagging measures to achieving best-in-class performance	1.50	0.22
Quality	15%	Quality standards throughout lifecycle	1.89	0.28
Schedule	27.9%	Reach forecast in-service delivery and key project milestones	1.34	0.37
Cost	27.1%	Development and execution of projects relative to budget, complete forecasts and cash flow accuracy	1.03	0.28
Compliance	10%	Compliance with regulation and protection of the environment including incident frequency	1.65	0.17
People	5%	Employee and contractor retention	1.57	0.08
		Performance Multiplier		**1.40**

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. The level of attainment of individual performance goals is recommended to the HRC Committee by the President & Chief Executive Officer of Enbridge for Messrs. Wuori and Zupan. The level of attainment of individual performance goals for Messrs. Maki, McGill, Neyland and Adams are recommended by their respective leaders to the Enbridge executive leadership team.

Summary of 2013 Performance Multipliers

The following table summarizes the corporate, business unit and individual performance multipliers for each executive, 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)
Mark A. Maki	25% x 0.94 = 0.24	50% x 1.17 = 0.58	25% x 1.60 = 0.40	1.22
Terrance L. McGill	25% x 0.94 = 0.24	50% x 1.18 = 0.59	25% x 1.60 = 0.40	1.23
Stephen J. Neyland	25% x 0.94 = 0.24	50% x 1.05 = 0.53	25% x 1.70 = 0.42	1.19
Stephen J. Wuori	25% x 0.94 = 0.24	50% x 1.22 = 0.60	25% x 1.75 = 0.44	1.28
Leon A. Zupan	25% x 0.94 = 0.24	50% x 1.18 = 0.59	25% x 1.70 = 0.42	1.25
Richard L. Adams	25% x 0.94 = 0.24	50% x 1.17 = 0.58	25% x 1.60 = 0.40	1.22

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Based on the overall performance multiplier determined from the above table, short term incentive awards for our executives were calculated as follows:

NEO	Base Salary (a)	Target (b)	Overall Performance Multiplier (c)	Calculated STIP (1) =(a) x (b) x (c)	Actual STIP
Mark A. Maki	$ 348,712	40%	1.22	$ 170,170	$ 220,170
Terrance L. McGill	383,904	40%	1.23	188,110	188,120
Stephen J. Neyland	252,206	35%	1.19	104,600	134,610
Stephen J. Wuori(2)	706,815	65%	1.28	589,220	589,336
Leon A. Zupan(2)(3)	411,662	60%	1.25	309,076	309,076
Richard Adams(2)	305,834	40%	1.22	149,247	162,538

(1) The calculated STIP may differ from the amounts presented due to rounding.

(2) The dollar amounts presented for Messrs. Wuori, Zupan and Adams have been converted from Canadian dollars, or CAD, to United States dollars, or USD, using the average exchange rate for 2013 of $1.00 CAD = $0.9709 USD.

(3) Effective January 1, 2013, Mr. Zupan s STIP target increased from 50% to 60% as a result of a compensation benchmarking review conducted by Mercer in November 2012, to maintain his competitive market positioning.

The calculated STIP may be adjusted for Messrs. Wuori and Zupan by a recommendation of the President & Chief Executive Officer of Enbridge to the HRC Committee, which must approve any such recommendation. Any adjustments for Messrs. McGill, Neyland and Adams would be reviewed and approved by Enbridge s executive leadership team for fairness and consistency with enterprise-wide compensation; while any adjustment for Mr. Maki would be recommended and approved by the President & Chief Executive Officer of Enbridge. Messrs. Maki, Neyland and Adams received additional STIP awards above the computed amounts as a result of exceptional performance and contribution to Enbridge and the Partnership.

Medium and Long-Term Incentives

Enbridge has three 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-based stock option plan, or PSOP, that includes eight-year options to acquire Enbridge common shares with performance and time vesting conditions; and
- An incentive stock option plan, or ISOP, which includes 10-year stock options to acquire Enbridge common shares with time vesting conditions.

Only the Enbridge executive leadership team, which includes Messrs. Wuori and Zupan, are eligible to receive grants under the PSOP.

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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, share price hurdles under the PSOP and performance measures under the 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:

		Amount Each Plan Contributes to Total Target Grant[(1)]		
NEO	Target Medium & Long-term Incentive Grant[(1)]	Performance Stock Units	Performance-Based Stock Options	Incentive Stock Options
Mark A. Maki	85.0%	25.5%		59.5%
Terrance L. McGill	85.0%	25.5%		59.5%
Stephen J. Neyland	70.0%	21.0%		49.0%
Stephen J. Wuori	250.0%	87.5%	75.0%	87.5%
Leon A. Zupan	200.0%	70.0%	60.0%	70.0%
Richard L. Adams	70.0%	21.0%		49.0%

(1) All values are expressed as percentages of base salary.

With the exception of Mr. Wuori and Mr. Zupan, actual award values, expressed as a percentage of base salary, range between 0% and 225% of the target medium and long-term incentive opportunity, based on individual performance history, succession potential, retention considerations and market competitiveness.

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 the mid-term objectives of Enbridge in the execution of its strategic plan. 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 2013 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.

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The second performance criterion is the Enbridge P/E Ratio relative to a selected comparator 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 comparator group for the P/E Ratio.

Price/Earnings Ratio Comparator 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 Messrs. Wuori and Zupan, 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 Messrs. Wuori and Zupan in 2012. The performance criteria for the 2012 performance stock options are Enbridge common share price hurdles of $48.00 CAD, $53.00 CAD and $58.00 CAD, weighted at 40%, 40% and 20%, respectively, which must be met by February 2019. Performance stock options were also granted in 2007 to the executive officers at that time which included only Mr. Wuori. The performance criteria for the 2007 performance stock options are Enbridge common share price hurdles of $25.00 CAD and $27.50 CAD, split adjusted for Enbridge s May 2011 stock split, respectively, which must be met by February 2014. As of December 31, 2013, the common share price hurdles for the 2007 have been met, therefore 100% of the 2007 grant is exercisable. As of December 31, 2013, the common share price hurdles for the 2012 grant have not been met, therefore none of the grant is exercisable.

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.

Service Agreements and Allocation of Compensation to the Partnership

As discussed above, our General Partner, Enbridge Management and affiliates of Enbridge provide managerial, administrative, and operational and director services to us pursuant to service agreements and we reimburse them for the costs of such services. Through an operational services agreement among Enbridge, affiliates of Enbridge and us, we are charged for the services of executive management resident in Canada, including the services of Messrs. Wuori, Zupan and Adams. Through a general and administrative services agreement among us, our General Partner, Enbridge Management and Enbridge Employee Services, Inc., a subsidiary of our General Partner, which we refer to as EES, we are charged for the services of executive management resident in the United States, including Messrs. McGill, Maki and Neyland. See Item 13. *Certain Relationships and Related Transactions, and Director Independence Other Related Party Transactions* for a discussion of these two agreements.

In connection with our annual budget process, we determine a budgeted allocation rate, which represents an estimated average percentage of expected time that will be spent by each of the NEOs on our business during the succeeding year. The NEOs provide input as to what those estimated percentages should be. Those estimates are revised each year based on historical experience and business plans for the following year. The NEOs do not keep logs of their time spent on our matters. Since the allocation rate is estimated, the actual time spent by an NEO on our behalf may vary from the budgeted allocation rate, and we may be allocated more or less of that NEO s compensation than the actual percentage of his time spent on our behalf in a given year. There were no other adjustments recognized for the years ended December 31, 2013, 2012 and 2011, for amounts reimbursed to us by Enbridge and its affiliates for the portion of the NEOs compensation allocated to us. For 2013, the percentage of time estimated to be spent by each of the NEOs on our matters was:

Mark A. Maki	75%
Terrance L. McGill	74%
Stephen J. Neyland	90%
Stephen J. Wuori	25%
Leon A. Zupan	37%
Richard L. Adams	50%

For services provided under the operational services agreement, as part of the annual budget process, we, Enbridge and affiliates of Enbridge, which we refer to as the Canadian service providers, agree on the amount to be allocated to us, which represents an estimate of a pro-rata reimbursement of each Canadian service provider s estimated annual departmental costs, net of amounts charged to other affiliates and amounts identifiable as costs of that Canadian service provider. The Canadian service providers charge us a monthly fixed fee based on the budgeted amount.

For services provided under the general and administrative services agreement, base salary costs of EES are allocated to us based on the percentage of time spent by EES employees, including three of the NEOs, on our behalf compared with the total time of all EES employees. We are also allocated a portion of the equity-based compensation expense of EES as determined in accordance with U.S. GAAP. Pension expenses of EES, other than expenses under Enbridge s nonqualified supplemental pension plan for U.S. domiciled employees, which we refer to as the SPP, are allocated to us based on the proportion that the total headcount of EES employees assigned to us bears to the total headcount of EES. For this purpose, an employee of EES is deemed to be assigned to us if he or she works on assets we own. Pension expenses of EES attributable to the SPP are allocated to us based upon the average budgeted allocation rate. EES allocates to us that portion of its compensation expense for the STIP equal to the total salaries of employees who perform work for us multiplied by the average budgeted allocation rate divided by EES s total salary expense.

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The compensation of our NEOs included in the tables below is established by Enbridge as described above. We have included in the following tables the full amount of compensation and related benefits provided for each of the NEOs for 2013, 2012 and 2011, together with the budgeted estimate of the approximate time spent by each NEO on our behalf and the approximate amount of compensation cost allocated to us for the years ended December 31, 2013, 2012 and 2011, as applicable. Since the amount of NEO compensation allocated to us is based on estimates of time spent on our behalf by the particular NEO, the compensation amounts allocated to us may not exactly reflect the amount of time that a certain NEO devoted to our business.

SUMMARY COMPENSATION TABLE

Name and[1] Principal Position	Year	Salary ($)	Stock Awards[1] ($)	Option Awards[2] ($)	Non-Equity Incentive Plan Compen-sation[3] ($)	Change in Pension Value and Nonqualified Deferred Compen-sation Earnings[4] ($)	All Other Compen-sation[5] ($)	Total ($)	Approximate Percentage of Time Devoted to Enbridge Energy Partners, L.P.	Approximate Amount Allocated to Enbridge Energy Partners, L.P.
(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(%)	($)
Mark A. Maki	2013	383,336	429,868	338,047	220,170	(236,000)	34,496	1,169,917	75	808,311
President, Principal Executive	2012	344,475	590,857	289,938	183,630	813,000	34,246	2,256,146	95	1,896,178
Officer and Director	2011	336,588	535,317	237,103	216,340	781,000	33,996	2,140,344	86	1,974,238
Terrance L. McGill	2013	380,391	462,395	439,139	188,120	90,000	35,510	1,595,555	74	1,396,922
Senior Vice President and	2012	367,660	712,584	415,786	177,160	371,000	35,822	2,080,012	90	1,809,538
Director	2011	366,309	734,843	435,372	237,060	442,000	35,853	2,251,437	86	2,080,741
Stephen J. Neyland[10]	2013	257,788	272,116	200,840	134,610	3,000	34,496	902,850	90	780,931
Vice President Finance	2012	241,198	249,187	163,217	129,750	162,000	33,532	978,884	90	824,613
	2011	234,998	151,454	125,248	139,150	157,000	33,496	841,346	86	763,286
Stephen J. Wuori[6][7]	2013	700,019	1,371,277	1,173,303	589,336	(572,000)	81,370	3,343,305	25	411,862
Executive Vice President	2012	684,520	3,031,025	1,506,549	610,554	2,550,000	85,911	8,468,559	25	400,335
Liquids Pipelines and Director	2011	606,976	2,661,202	572,988	632,130	2,003,000	218,224	6,694,520	25	346,186
Leon A. Zupan[7][8]	2013	411,557	622,531	478,293	309,076	294,000	182,428	2,297,885	37	835,300
Executive Vice President and	2012	388,533	485,620	466,738	239,830	894,000	101,148	2,575,869	57	518,792
Director	2011									
Richard L. Adams[7][9]	2013	303,644	398,464	386,288	162,538	(113,000)	50,617	1,188,551	50	982,111
Senior Vice President	2012									
Operations	2011									

(1) The compensation expense associated with Performance Stock Units, or PSUs, for each NEO, that are reflected in this column represent one-third of the market value for each year the PSUs are outstanding and are measured based on the number of respective units granted, dividends reinvested, cliff-vested, the actual or forecast performance multiplier with respect to the PSUs, and the market value or payout amount at the end of each period. For example, 2013 includes one-third of the market values for PSUs issued in 2013, 2012 and 2011. In 2013, the compensation expense recorded for PSUs granted in 2013, 2012 and 2011 include performance multipliers for the respective years, which are estimated to be 2.0 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 market value for each PSU grant represents the weighted average closing price of an Enbridge common share as quoted on the NYSE for the USD denominated PSUs and the Toronto Stock Exchange, or TSX, for CAD denominated PSUs for the 20 consecutive days prior to the beginning of the new year. PSUs granted for 2013, 2012 and 2011 were denominated in both USD and CAD. The PSU expense in CAD is converted to USD based on the average exchange rate for the 20 trading days prior to the end of the term. The PSUs were granted on January 1, 2013, 2012 and 2011, respectively. The actual payout amounts for the 2011 PSUs that vested on December 31, 2013 were based on average share prices of $41.56 USD and $44.21 CAD, for the respective USD denominated PSUs and CAD denominated PSUs. Compensation expense as reported in the Summary Compensation Table above for Stock Awards has been determined using the following assumptions:

	2013	2012	2011	2010[(a)]	2009[(a)]
End of Period Market Value USD	$ 41.65	$ 42.27	$ 35.75	$ 27.71	$ 22.41

End of Period Market Value CAD	$ 44.30	$ 41.69	$ 36.38	$ 27.92	$ 23.57
20-day average $1CAD to USD exchange rates as of year end	$ 0.9399	$ 1.0104	$ 0.9768	$ 0.9927	$ 1.0544
Exchange rate on payout date	N/A	N/A	N/A	N/A	N/A
Performance multiplier	N/A	N/A	N/A	N/A	N/A
Assumed performance multiplier	2.00	2.00	2.00	2.00	2.00

(a) Where appropriate, prices adjusted for the May 2011 Enbridge stock split.

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(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. Enbridge granted PSOs to Messrs. Wuori and Zupan during 2012. 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			PSOP	
Assumption	**2013**	**2012**	**2011**	**2013**	**2012**	**2011**
Expected option term in years (USD)	6	6	6	N/A	N/A	N/A
Expected volatility (USD)	19.97%	22.80%	22.40%	N/A	N/A	N/A
Expected dividend yield (USD)	2.77%	2.95%	3.41%	N/A	N/A	N/A
Risk-free interest rate (USD)	1.05%	1.17%	2.80%	N/A	N/A	N/A
Expected option term in years (CAD)	6	6	6	N/A	8	N/A
Expected volatility (CAD)	16.78%	19.00%	17.80%	N/A	16.10%	N/A
Expected dividend yield (CAD)	2.77%	2.95%	3.41%	N/A	2.80%	N/A
Risk-free interest rate (CAD)	1.34%	1.45%	2.88%	N/A	1.60%	N/A

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 has been converted to USD using the exchange rates as set forth in the tables below.

		ISOP			PSOP	
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Exercise price in CAD	$ 44.83	$ 38.34	$ 28.78	N/A	$ 39.34	N/A
Exercise price in USD	$ 43.84	$ 38.65	$ 28.99	N/A	$ 39.77	N/A
Grant date exchange rate for $1 USD	$ 1.0250	$ 0.9888	$ 0.9885	N/A	$ 0.9891	N/A

		ISOP			PSOP	
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Vesting period in years	4	4	4	N/A	5	N/A
Option fair value on grant date in CAD	$ 5.45	$ 5.00	$ 4.00	N/A	$ 4.25	N/A
Option fair value on grant date in USD	$ 6.26	$ 6.11	$ 5.11	N/A	$ 4.30	N/A
Average full year exchange rate for $1 USD	$ 1.0299	$ 0.9996	$ 0.9891	N/A	$ 0.9884	N/A

(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. The Non-Equity Incentive Plan Compensation for Messrs. Maki, Neyland and Adams in 2013 includes an additional amount received during 2013 that was awarded for exceptional performance and contribution to Enbridge and the Partnership.

(4) Due to higher discount rates in 2013 compared to 2012, the higher discount rate reduced the present value of accumulated benefits.

(5) The table which follows labeled All Other Compensation sets forth the elements comprising the amounts presented in this column.

(6) Mr. Wuori was elected as an officer of Enbridge Management and our General Partner in January 2008, prior to which he held other responsibilities with Enbridge. Mr. Wuori is also an executive officer of Enbridge with responsibility for other affiliates of Enbridge in addition to those for our General Partner and Enbridge Management.

(7) Messrs. Wuori, Zupan and Adams are compensated by affiliates of Enbridge in CAD, which we have converted to USD using the weighted average exchange rates for the entire years ended December 31, 2013, 2012 and 2011 of $1.0299 CAD = $1USD, $0.9996 CAD = $1USD and $0.9891 CAD = $1USD, respectively. The costs associated with the PSUs and options Messrs. Wuori, Zupan and Adams granted in 2013, 2012 and 2011 were borne by Enbridge and other affiliates where they also officers. We are allocated a portion of the remaining elements of Messrs. Wuori, Zupan and Adams compensation pursuant to the terms of the Operational Services Agreement among Enbridge, Enbridge Operational Services, Inc., or EOSI, and Enbridge Pipelines, both subsidiaries of

Enbridge.

(8) Mr. Zupan was elected as Executive Vice President Chief Operating Officer of Enbridge in May 2013 prior to which he held the role of Executive Vice President Gas Pipelines.

(9) Mr. Adams was elected as an officer of Enbridge Management and our General Partner in May 2013, prior to which he held other responsibilities with Enbridge.

(10) The compensation expense associated with the Restricted Stock Units, or RSU s with respect to Mr. Neyland are reflected in column (e), Stock Awards, and represent one-third of the market value for each year the RSUs are outstanding. The RSUs are measured based on the number of respective units granted, dividends reinvested, cliff-vested, and the market value or payout amount at the end of each period. For example, 2012 and 2011 include one-third of the market values for the RSUs issued in 2010, while 2011 would also include one-

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third of the market value for RSUs issued in 2009. RSUs do not have performance multipliers used in determining the payout amount. 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. The market value for the RSU grant represents the weighted average closing price of an Enbridge common share as quoted on the NYSE for the USD denominated RSUs for the 20 consecutive days prior to the end of the performance period. The RSUs granted to Mr. Neyland for 2009 and 2010 were denominated in only USD. The actual payout amounts for the 2009 RSUs that vested on November 30, 2011 and the 2010 RSUs that vested on November 30, 2012 were based on average share prices of $34.57 USD and $39.39 USD, respectively.

ALL OTHER COMPENSATION

(For the years ended December 31, 2013, 2012 and 2011)

Name	Year	Flexible Benefits(2) $	401(k) Matching Contributions(3) $	Other Benefits(4) $	Total
Mark A. Maki	2013	20,000	12,750	1,746	34,496
	2012	20,000	12,500	1,746	34,246
	2011	20,000	12,250	1,746	33,996
Terrance L. McGill	2013	20,000	12,750	2,760	35,510
	2012	20,000	12,500	3,322	35,822
	2011	20,000	12,250	3,603	35,853
Stephen J. Neyland	2013	20,000	12,750	1,746	34,496
	2012	20,000	11,786	1,746	33,532
	2011	20,000	11,750	1,746	33,496
Stephen J. Wuori(1)	2013	73,449		7,921	81,370
	2012	74,481		11,430	85,911
	2011	72,028		146,196	218,224
Leon A. Zupan(1)	2013	46,619	10,277	125,532	182,428
	2012	65,138	7,039	28,971	101,148
	2011				
Richard L. Adams(1)	2013	25,692	11,012	13,913	50,617
	2012				
	2011				

(1) The amounts reported in this table for Mr. Wuori, who is domiciled in Canada, has been converted from CAD to USD using the average exchange rate for the years ended December 31, 2013, 2012 and 2011 of $1.0299 CAD = $1 USD, $0.9996 CAD = $1 USD and $0.9891 CAD = $1 USD, respectively. Mr. Zupan s amounts were converted using the same rates, excluding the 401k matching contribution amount and $30,000 in Flex Benefits, which were already denoted in USD. Mr. Adams s amounts were also converted using the same rates, excluding the 401k matching contribution amount and $20,000 in Flex Benefits, which were already denoted in USD.

(2) Flexible benefits for our U.S.-domiciled NEOs represent a perquisite allowance that is paid in cash as additional compensation. Our NEOs domiciled in Canada also receive flexible benefits based on their family status and base salary. For our NEOs that are domiciled in Canada, the flexible benefits can be used to purchase additional benefits, paid in cash, or be applied as contributions to the Enbridge Stock Purchase and Savings Plan.

(3) Our NEOs that are domiciled in the United States and 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.

(4) Other benefits include parking for our U.S. NEOs and professional financial services, medical, parking, fitness, home security, air travel, relocation and internet services for our Canadian NEOs.

Enbridge does not maintain any compensation plans for the benefit of the NEOs under which equity interests in us or Enbridge Management may be awarded. However, Enbridge allocates to us a portion of the compensation expense it

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recognizes in accordance with the authoritative guidance for share-based compensation in connection with recording the fair value of its performance and restricted stock units and outstanding stock options granted to certain of its officers, including the NEOs. The costs we are charged with respect to option grants represent a portion of the costs determined in accordance with U.S. GAAP.

The PSUs are granted to the NEOs pursuant to the PSUP 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 granted in 2011 through 2013 to our U.S. domiciled NEOs are denominated in USD while those granted to NEOs domiciled in Canada are denominated in CAD. The exceptions are Mr. Zupan and Mr. Adams, who have both transferred between the U.S. and Canada during the year; Mr. Zupan has both CAD and USD grants and Mr. Adams has only USD grants. The three tables which follow set forth information concerning performance stock units and stock options granted during the year ended December 31, 2013, outstanding at December 31, 2013 and the number of awards vested and exercised during the year ended December 31, 2013 by each of the NEOs.

GRANTS OF PLAN-BASED AWARDS

				Estimated Future Payouts Under Non-Equity Incentive Plan Awards[(2)]			Estimated Future Payouts Under Equity Incentive Plan Awards[(3)]			All Other Option Awards: Number of Securities Underlying Options[(4)]	Exercise or Base Price of Option Awards [(4)]	Date Fair Value of Stock and Option Awards [(3)(4)]
Name	**Plan Name[(1)]**	**Approval Date**	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**(#)**	**($/Sh)**	**($)**
(a)	**(b)**	**(b)**	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(j)**	**(k)**	**(l)**
Mark A. Maki	PSUP	13-Feb-13	1-Jan-13				2,438	3,900	7,800			164,853
	ISOP	13-Feb-13	27-Feb-13							63,600	43.84	398,136
	STIP	3-Feb-14	27-Feb-14		139,485	278,970						
Terrance L. McGill	PSUP	13-Feb-13	1-Jan-13				2,688	4,300	8,600			181,761
	ISOP	13-Feb-13	27-Feb-13							70,150	43.84	439,139
	STIP	3-Feb-14	27-Feb-14		153,562	307,123						
Stephen J. Neyland	PSUP	13-Feb-13	1-Jan-13				1,438	2,300	4,600			97,221
	ISOP	13-Feb-13	27-Feb-13							41,050	43.84	256,973
	STIP	3-Feb-14	27-Feb-14		88,272	176,544						
Stephen J. Wuori	PSUP	13-Feb-13	1-Jan-13				9,500	15,200	30,400			640,326
	ISOP	13-Feb-13	27-Feb-13							120,850	43.74	642,562
	STIP	3-Feb-14	27-Feb-14		459,430	918,860						
Leon A. Zupan	PSUP	13-Feb-13	1-Jan-13				4,594	7,350	14,700			310,685
	ISOP	13-Feb-13	27-Feb-13							53,150	43.84	332,719
	STIP	3-Feb-14	27-Feb-14		246,997	493,994						
Richard L. Adams	PSUP	13-Feb-13	1-Jan-13				2,031	3,250	6,500			137,378
	ISOP	13-Feb-13	27-Feb-13							53,150	43.84	332,719
	STIP	3-Feb-14	27-Feb-14		122,333	244,667						

(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. STIP refers to the Enbridge Short Term Incentive Plan (2006), a non-equity performance-based incentive plan.

(2) The estimated future payouts under non-equity incentive award plans represents 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. The initial PSUs granted are increased for quarterly dividends paid during the three-year period on an Enbridge common share that are

reinvested in additional PSUs. 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 the long range plan of the organization 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.

The threshold at which PSUs are paid out represents 62.5% of the number of PSUs initially granted increased by additional PSUs resulting from reinvested dividends and is the lowest level at which PSUs will be paid out based on the performance criteria discussed above. The target level at which PSUs are issued represents 100% of the number of PSUs initially granted increased by additional PSUs resulting from reinvested notional dividends 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 increased by additional PSUs resulting from reinvested dividends 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 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 U.S.-based NEOs in 2013 was $42.27 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, 2013. The grant date fair value for each PSU granted to each of our Canadian based NEOs was $41.69 CAD, representing the volume weighted average closing price of one Enbridge common share as quoted on the TSX for the 20 days immediately preceding the start of the performance period that began on January 1, 2013. We have converted the grant date fair value for the Canadian PSU grants made from CAD to USD using an exchange rate of $1.0104 CAD = $1 USD, representing the weighted average noon rate for 20 trading days immediately preceding the performance period that began on January 1, 2013.

(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 TSX or 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 2013, 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 $44.83 CAD for Canadian-domiciled NEOs and $43.84 USD for NEOs domiciled in the United States.

The amounts included as the grant date fair value for the 2013 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:

USD Option Value	**CAD Option Value**
6 years expected term;	6 years expected term;
19.97% expected volatility;	16.78% expected volatility;
2.77% expected dividend yield; and	2.77% expected dividend yield; and
1.05% risk free interest rate.	1.34% risk free interest rate.

The fair value of options granted as computed using these assumptions is $6.26 USD or $5.45 CAD. The $5.45 CAD option value and the $44.83 CAD exercise price have been converted to USD using an exchange rate of $1.0250 CAD = $1 USD representing the noon buying rate in New York for transfers of CAD on the grant date of February 27, 2013. The grant date fair value is expensed over the shorter of the vesting period for the options, generally 4 years, and in the year granted for employees age 55 and over and eligible for early retirement. Messrs. McGill, Zupan, and Wuori were 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 they were awarded is expensed in the year granted.

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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)(2) (c)	Option Exercise Price(3) ($) (e)	Option Expiration Date(1)(2) (f)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(4) (#) (i)	Equity Incentive Plan Awards: Market or Payout of Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
Mark A. Maki		63,600	43.84	27-Feb-23	4,013	334,309
	15,413	46,237	38.65	2-Mar-22	4,712	392,538
	38,200	38,200	28.99	14-Feb-21		
	25,500	8,500	21.97	16-Feb-20		
	45,700		15.80	25-Feb-19		
	5,200		20.17	19-Feb-18		
Terrance L. McGill		70,150	43.84	27-Feb-23	4,425	368,597
	17,013	51,037	38.65	2-Mar-22	5,242	436,643
	42,600	42,600	28.99	14-Feb-21		
	36,750	12,250	21.97	16-Feb-20		
	99,000		15.80	25-Feb-19		
	99,000		20.17	19-Feb-18		
Stephen J. Neyland		41,050	43.84	27-Feb-23	2,367	197,157
	399	5,573	38.65	2-Mar-22	3,812	317,559
	9,376	23,752	38.65	2-Mar-22		
	11,150	22,300	28.99	14-Feb-21		
	3,850	3,850	21.97	16-Feb-20		
	2,750		15.80	25-Feb-19		
Stephen J. Wuori		120,850	43.74	27-Feb-23	15,634	1,302,374
	29,325	87,975	38.77	2-Mar-22	17,781	1,481,147
	50,000	50,000	29.11	14-Feb-21		
		617,600	39.77	15-Aug-20		
	60,000	20,000	22.34	16-Feb-20		
	120,000		15.78	25-Feb-19		
	120,000		19.90	19-Feb-18		
	90,000		16.30	9-Feb-17		
	96,600		15.79	13-Feb-16		
	330,000		17.02	15-Aug-15		
	91,600		12.75	3-Feb-15		
	78,000		9.65	4-Feb-14		
Leon A. Zupan		53,150	43.84	27-Feb-23	7,564	630,044
	20,713	62,137	38.77	2-Mar-22	5,451	454,042
	54,300	54,300	29.11	14-Feb-21		
		169,400	39.77	15-Aug-20		
	25,050	8,350	22.34	16-Feb-20		
	46,400		15.78	25-Feb-19		
	46,400		19.90	19-Feb-18		

	17,000		16.30	9-Feb-17		
	16,200		15.79	13-Feb-16		
	18,400		12.75	3-Feb-15		
Richard L. Adams		53,150	43.84	27-Feb-23	3,344	278,591
	12,988	38,962	38.65	2-Mar-22	4,024	335,201
	23,600	23,600	28.99	14-Feb-21		
	25,500	8,500	21.97	16-Feb-20		
	64,000		15.80	25-Feb-19		

(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) PSOs were provided to certain of our NEOs on August 15, 2007 and August 15, 2012, 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 20% annually over five years. As of December 31, 2013, the common share price targets for the PSOs granted on August 15, 2007 were met, therefore 100% of the 2007 grant was vested or exercisable; however, none of the target common share prices were met for the PSOs in 2012 so no grants were vested or exercisable.

(3) The exercise prices of the ISOs and PSOs issued during 2007 and prior years are denominated in CAD and have been adjusted for the noon exchange rate on the date of grant. 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. Beginning in 2008, ISOs granted to NEOs domiciled in the United States are denominated in USD while those NEOs domiciled in Canada are denominated in CAD. PSOs are granted in CAD to NEOs domiciled in either Canada or the United States. The ISOs and PSOs denominated in CAD have been converted to USD using the exchange rate on the grant dates as set forth below:

Grant Date	Option Exercise Price CAD	Exchange Rate CAD/ USD	Option Exercise Price USD
February 4, 2004	12.8600	0.7504	9.6501
February 3, 2005	15.8400	0.8046	12.7449
February 13, 2006	18.2350	0.8660	15.7915
February 9, 2007	19.1300	0.8519	16.2968
August 15, 2007	18.2850	0.9306	17.0160
February 19, 2008	20.2100	0.9843	19.8927
February 25, 2009	19.8050	0.7964	15.7727
February 16, 2010	23.2950	0.9591	22.3422
February 14, 2011	28.7750	1.0116	29.1088
March 5, 2012	38.3400	1.0113	38.7732
August 15, 2012	39.3400	1.0110	39.7727
February 27, 2013	44.8300	0.9756	43.7361

(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 common share price of one Enbridge common share on the NYSE at the weighted average noon rate for 20 trading days at year end 2013 equating to $41.65 per share or on the TSX of $44.30 per common share converted to USD as $41.65 per share at the conversion rate of $1.0636 CAD = $1 USD. The market or payout values presented assume a performance multiplier of 2.0 for PSUs granted in 2013 and 2012, which amounts represent the maximum level attainable based on forecasts of performance at December 31, 2013.

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OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting[1] (#)	Value Realized on Vesting[2] ($)
(a)	(b)	(c)	(d)	(e)
Mark A. Maki			6,552	544,607
Terrance L. McGill			6,770	562,761
Stephen J. Neyland	5,000	127,837	3,494	290,457
Stephen J. Wuori	330,000	8,144,998	15,278	1,269,958
Leon A. Zupan			6,984	580,552
Richard L. Adams			3,713	308,611

(1) The number of common shares acquired on vesting for stock awards represents the number of PSUs issued in 2011 and the related dividends paid that were used to acquire additional PSUs, all of which matured on December 31, 2013. 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 2011 is expected to occur on or about March 14, 2014.

(2) The value realized on vesting is determined based on the final value of an Enbridge common share of $41.56 USD for the NEOs domiciled in the U.S. or $44.21 CAD for the NEOs domiciled in Canada. In each case the common share price is multiplied by a 2.0 performance factor multiplied by the number of PSUs, and is then converted to USD, as applicable, using an average exchange rate of $1.0637 CAD = $1USD for the 20 trading days prior to the maturity date of December 31, 2013.

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. 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 credits, based on the employees pensionable pay, age and years of service, 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; the Pension Plans provide a yearly pension payable in the normal form (60% joint and survivor) equal to: (a) 1.6% of the average of the participant s highest annual salary during three consecutive years out of the last ten years of credited service multiplied by (b) the number of credited years of service. The pension is offset, after age 65, by 50% of the participant s Social Security benefit, pro-rated by years in which the participant has both credited service and Social Security coverage. 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 United States and Canadian plans are indexed at 50% of the annual increase in the United States and Canadian consumer price index, respectively. For employees hired after January 1, 2002, the Pension Plans provide cash balance benefits.

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

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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, 2013 assuming the eligibility requirements for an unreduced pension have been satisfied. We have converted pensions payable in CAD into USD at the rate of $1.0299 CAD = $1.00 USD, the exchange rate for the year ended December 31, 2013. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	4.70% at year end 2013
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	PPA generational annuitant and non-annuitant tables (RP-2000 with generational mortality improvements)

(1) This is age 60 for all executives except for Messrs. Maki and Adams, who are eligible for an unreduced pension at age 55, and age 56 for Mr. Wuori.

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PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service[(1)] (#) (c)	Present Value of Accumulated Benefit ($) (d)
Mark A. Maki	EI RPP	1.92	82,000
	EI SPP	1.92	152,000
	US QPP	25.40	1,570,000
	US SPP	25.40	1,140,000
Terrance L. McGill	US QPP	11.50	231,000
	US SPP	11.83	1,789,000
Stephen J. Neyland	US QPP	11.50	181,000
	US SPP	9.00	385,000
Stephen J. Wuori[(2)]	EI RPP	19.67	1,063,000
	EI SPP	19.67	9,860,000
	US QPP	13.83	322,000
	US SPP	13.83	86,000
Leon A. Zupan	EI RPP	25.60	1,182,000
	EI SPP	25.60	2,143,000
	US QPP	0.98	65,000
	US SPP	0.98	93,000
Richard Adams	EI RPP	0.79	34,000
	EI SPP	0.79	57,000
	US QPP	26.41	1,000,000
	US SPP	11.71	1,361,000

(1) For Messrs. McGill, and Neyland, US SPP service represents years of service as a senior management employee. Mr. Adams has 12.50 years and Messrs. Maki, Wuori and Zupan each have 14.00 years of service as a senior management employee.

(2) Mr. Wuori s highest salary for service prior to January 1, 2000 includes bonuses.

Employment and Severance Agreements

Enbridge entered into an executive employment agreement with each of Stephen J. Wuori, Director and Executive Vice President Liquids Pipelines of Enbridge Management and our General Partner, and Leon A. Zupan, Executive Vice President. The term of each of the agreements continues until the earlier of the applicable 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. Messrs. Maki, McGill, Neyland and Adams do not have an employment agreement with us or any other Enbridge affiliate. Each of the agreements provides that Enbridge will pay severance benefits to each of Messrs. Wuori and Zupan as set forth in the table below, if such executive officer 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 agreement with Mr. Wuori was entered into prior to that time.

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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	None	Payable in full if executive has worked the entire calendar year. Otherwise none.	Performance options are prorated to resignation date. 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. Performance stock units are forfeited.	None	Credited service no longer earned.
Retirement	None	Current year s incentive is pro-rated based on retirement date.	Performance stock units are prorated to retirement date. 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.
Involuntary Termination (Not for Cause)	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.	Vested stock options are exercisable in accordance with their terms. Performance stock units are prorated to date of termination and the value is assessed and paid at the end of the term. 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 added to the final pension calculation.
Termination (Constructive Dismissal)					
Termination (Change of Control)			All stock options vest. All performance stock units mature and value is assessed and paid based on performance measures achieved to that time.		

[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;

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- 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 (any notice period for an involuntary not for cause termination is included as active employment) 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).

For purposes of each of the employment agreements of Mr. Wuori, a change of control means:

- The sale to a person or acquisition by a person not affiliated with Enbridge or its subsidiaries of net assets of Enbridge or its subsidiaries having a value greater than 50% of the fair market value of the net assets of Enbridge and its subsidiaries determined on a consolidated basis prior to such sale whether such sale or acquisition occurs by way of reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise;

- Any change in the holding, direct or indirect, of shares of Enbridge by a person not affiliated with Enbridge as a result of which such person, or a group of persons, or persons acting in concert, or persons associated or affiliated with any such person or group within the meaning of the Securities Act (Alberta), are in a position to exercise effective control of Enbridge whether such change in the holding of such shares occurs by way of takeover bid, reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise; and for the purposes of this Agreement, a person or group of persons holding shares or other securities in excess of the number which, directly or following conversion thereof, would entitle the holders thereof to cast 20% or more of the votes attaching to all shares of Enbridge which, directly or following conversion of the convertible securities forming part of the holdings of the person or group of persons noted above, may be cast to elect directors of Enbridge shall be deemed, other than a person holding such shares or other securities in the ordinary course of business as an investment manager who is not using such holding to exercise effective control, to be in a position to exercise effective control of Enbridge;

- Any reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction involving Enbridge where shareholders of Enbridge immediately prior to such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction hold less than 60% of the shares of Enbridge or of the continuing corporation following completion of such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, transfer, sale or other transaction;

- Enbridge ceases to be a distributing corporation as that term is defined in the Canada Business Corporations Act;

- Any event or transaction which the Enbridge board of directors, in its discretion, deems to be a change of control; or

The Enbridge board of directors no longer comprises a majority of incumbent directors, who are defined as directors who were directors immediately prior to the occurrence of the transaction, elections or

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appointments giving rise to a change of control and any successor to an incumbent director who was recommended for election at a meeting of Enbridge shareholders, or elected or appointed to succeed any incumbent director, by the affirmative vote of the directors, which affirmative vote includes a majority of the incumbent directors then on the board of directors.

Both Messrs. Wuori and Zupan are subject during his employment (and for two years 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 to Mr. Zupan, Enbridge would owe incremental benefits with a value of approximately $6 million, while Enbridge would owe $14 million for Mr. Wuori. Such amounts assume that termination was effective as of December 31, 2013, and as a result include amounts earned through such time and are estimates of the amounts which would be paid out to each of Messrs. Wuori and Zupan 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 Enbridge Management, as the delegate of our General Partner. The boards of directors of Enbridge Management and our General Partner, which are comprised of the same persons, perform 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 or Enbridge Management do not receive any additional compensation for serving in those capacities. Effective April 30, 2013, Leon A. Zupan resigned as member of the boards of directors of Enbridge Management and our General Partner. In addition, Mr. C. Gregory Harper was appointed to the boards of directors of Enbridge Management, our General Partner and Midcoast Holdings, L.L.C. effective January 30, 2014.

Under the Director Compensation Plan, directors shall receive an annual retainer of $115,000, with no additional fees for attending regular meetings. The annual retainer paid to the Chairman of the Board is $20,000 and the annual retainer paid to the Chairman of the Audit Committee is $15,000. The out-of-state travel fee is $1,500 per meeting. In addition, the Director Compensation Plan has set the retainer paid to a Director serving as Chairman of any Special Committee that may be constituted from time to time to $5,000 for each assignment plus additional amounts to be paid at the Board s discretion depending on the complexity of the project and time involved. Each member of the Special Committee receives $1,500 per meeting.

The Corporate Governance Guidelines provide an expectation that independent directors will hold a personal investment in either or both of us or Enbridge Management, 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 January 1, 2011 or five years from the date he or she became a director. All of our independent directors are in compliance with this requirement.

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DIRECTOR COMPENSATION

Name (a)	Fees Earned or Paid in Cash [(1)] ($) (b)
Jeffrey A. Connelly *Chairman of the Board*	186,500
J. Herbert England *Audit Committee Chairman*	139,000
Dan A. Westbrook	152,500
Rebecca B. Roberts	146,500

(1) First quarter retainer fees were, in each instance, paid in the fourth quarter of the year prior, thus the above fees represent the period of April 2013 thru March 2014.

Each director is indemnified for actions associated with being a director to the fullest extent permitted under Delaware law and we maintain errors and omissions insurance.

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COMPENSATION REPORT OF THE BOARD OF DIRECTORS

The Board of Directors of Enbridge Energy Management, L.L.C., as delegate of the General Partner of Enbridge Energy Partners, L.P., 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/ Mark A. Maki Mark A. Maki *President, Principal Executive Officer and* *Director*	/s/ Terrance L. McGill Terrance L. McGill *Senior Vice President and* *Director*
/s/ Stephen J. Wuori Stephen J. Wuori *Executive Vice President Liquids* *Pipelines and Director*	/s/ J. Richard Bird J. Richard Bird *Director*
/s/ Jeffrey A. Connelly Jeffrey A. Connelly *Director*	/s/ C. Gregory Harper C. Gregory Harper *Director*
/s/ J. Herbert England J. Herbert England *Director*	/s/ Dan A. Westbrook Dan A. Westbrook *Director*
/s/ Rebecca B. Roberts Rebecca B. Roberts *Director*	

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

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information as of February 14, 2014 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 Management, L.L.C.	i-units	64,984,750	100.0
1100 Louisiana St., Suite 3300			
Houston, TX 77002			
Enbridge Energy Company, Inc.	Class A common units	46,518,336	18.3
1100 Louisiana St., Suite 3300	Class B common units	7,825,500	100.0
Houston, TX 77002	Series 1 Preferred Units	48,000,000	100.0

We do not have any shares that have been approved for issuance under an equity compensation plan.

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SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 14, 2014 with respect to each class of our units and the listed shares of Enbridge Management beneficially owned by the NEOs and directors of the General Partner and Enbridge Management and all executive officers and directors of the General Partner and Enbridge Management as a group:

	Enbridge Energy Management, L.L.C.			Enbridge Energy Partners, L.P.		
Name	**Title of Class**	**Number of Shares[1]**	**Percent of Class**	**Title of Class**	**Amount and Nature of Beneficial Ownership[1]**	**Percent of Class**
Jeffrey A. Connelly[2]	Listed Shares		*	Class A common units	20,000	*
J. Herbert England	Listed Shares		*	Class A common units	8,626	*
Rebecca B. Roberts	Listed Shares		*	Class A common units	4,000	*
Dan A. Westbrook[3]	Listed Shares		*	Class A common units	23,000	*
J. Richard Bird[6]	Listed Shares	87,780	*	Class A common units		*
C. Gregory Harper	Listed Shares		*	Class A common units		*
Mark A. Maki[4]	Listed Shares	2,632	*	Class A common units	4,000	*
Terrance L. McGill	Listed Shares	4,635	*	Class A common units	8,000	*
Stephen J. Wuori	Listed Shares		*	Class A common units		*
Leon A. Zupan	Listed Shares		*	Class A common units		*
Richard L. Adams	Listed Shares		*	Class A common units		*
Stephen J. Neyland[7]	Listed Shares	8,016	*	Class A common units		*
All executive officers, directors and nominees as a group (21 persons)[5]	Listed Shares	106,340	*	Class A common units	76,215	*

* 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 or Listed Shares attributed to him or her.

(2) Of the 20,000 Class A common units deemed beneficially owned by Mr. Connelly, 20,000 Class A common units are held in the Susan K. Connelly Family Trust, of which Mr. Connelly is the trustee and a beneficiary.

(3) Of the 23,000 Class A common units deemed beneficially owned by Mr. Westbrook, 16,000 Class A common units are held by The Westbrook Trust, for which Mr. Westbrook is the trustee and beneficiary, and 7,000 Class A common units are held by the Mary Ruth Westbrook Trust, for which Mr. Westbrook is the sole trustee and beneficiary.

(4) Of the 4,000 Class A common units beneficially owned by Mr. Maki, 3,000 Class A common units are held directly by Mr. Maki, and 1,000 Class A common units are held by Mr. Maki as Personal Representative of his mother s estate.

(5) The 588.562 Class A common units beneficially owned by Ms. Coy are held in an Individual Retirement Account established for her benefit. The dividends were reinvesting into Class A units.

(6) The 87,780 Listed Shares owned by Mr. Bird are held by an investment holding corporation over which he exercises full control and direction.

(7) The 8,016 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.

Item 13. Certain Relationships and Related Transactions, and Director Independence

INTEREST OF THE GENERAL PARTNER IN THE PARTNERSHIP

At December 31, 2013, our General Partner had the following ownership interests in us:

	Quantity	Effective Ownership %
Series 1 preferred units representing partner interest	48,000,000	100.0%
Direct ownership		
Class A common units representing limited partner interest	46,518,336	14.0%
Class B common units representing limited partner interest	7,825,500	2.3%
General Partner interest	6,648,511	2.0%
Indirect ownership		
Enbridge Management shares (Listed and Voting)	7,449,431	2.2%
Total effective ownership	68,441,778	20.5%

INTEREST OF ENBRIDGE MANAGEMENT IN THE PARTNERSHIP

At December 31, 2013, Enbridge Management owned 63,743,099 i-units, representing a 19.2% limited partner interest in us. The i-units are a special class of our limited partner interests. All of our i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management s limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the partnership agreement and the provisions of Enbridge Management s limited liability company agreement, the number of outstanding Enbridge Management shares and the number of our i-units will at all times be equal.

CASH DISTRIBUTIONS

As discussed in Part II, Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations*, we make quarterly cash distributions of our available cash to our General Partner and the holders of our common units. The holders of our i-units and Class A common units received in-kind distributions under the partnership agreement. Our General Partner receives incremental incentive cash distributions on the portion of cash distributions that exceed certain target thresholds on a per unit basis as follows:

	Unitholders	General Partner
Quarterly Cash Distributions per Unit:		
Up to $0.295 per unit	98%	2%
First Target $0.295 per unit up to $0.35 per unit	85%	15%
Second Target $0.35 per unit up to $0.495 per unit	75%	25%
Over Second Target Cash distributions greater than $0.495 per unit	50%	50%

During 2013, we paid cash and incentive distributions to our General Partner for its general partner ownership interest of approximately $139.3 million and cash distributions of $101.1 million and $17.0 million in connection with its ownership of the Class A and Class B common units, respectively. The cash distributions we make to our General Partner for its general partner ownership interest exclude an amount equal to 2% of the i-unit distributions to maintain its 2% general partner interest.

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IN-KIND DISTRIBUTIONS

Enbridge Management, as owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our Class A and Class B common units, we issue additional i-units to Enbridge Management in an amount determined by dividing the cash amount distributed per limited partner unit by the average price of one of Enbridge Management s listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management s shares multiplied by the number of shares outstanding on the record date. In 2013, 2012 and 2011, distributed a total of 3,769,989, 2,632,090 and 2,402,228 i-units to Enbridge Management, on a split-adjusted basis, and retained cash totaling approximately $113.8 million, $85.0 million and $75.7 million in connection with these in-kind distributions.

GENERAL PARTNER CONTRIBUTIONS

Pursuant to our partnership agreement, our General Partner is at all times required to maintain its 2% general partner ownership interest in us. During 2013, 2012 and 2011, in connection with our various issuances and sales of Class A common units, our General Partner contributed approximately $10.8 million, $9.4 million and $18.2 million, respectively, to us to maintain its 2% general partner ownership interest.

OTHER RELATED PARTY TRANSACTIONS

We do not directly employ any of the individuals responsible for managing or operating our business, nor do we have any directors. We obtain managerial, administrative and operational services from our General Partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, Enbridge Management and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our General Partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

Administrative and Workforce Related Services

Enbridge and its affiliates provide management and 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, nor do we have any directors. We obtain managerial, administrative and operational services from our General Partner, Enbridge Management and affiliates of Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our General Partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

Service Agreements

Our General Partner, Enbridge Management, Enbridge and affiliates of Enbridge provide managerial, administrative, operational and director services to us pursuant to service agreements, and we reimburse them for the costs of those services. Through an operational services agreement among Enbridge, Enbridge Operational Services, Inc., or EOSI, and Enbridge Pipelines Inc., or Enbridge Pipelines, both subsidiaries of Enbridge, all of whom we refer to as the Canadian service providers, and us, we are charged for the services of Enbridge employees resident in Canada. Through a general and administrative services agreement among us, our General Partner, Enbridge Management and Enbridge Employee Services, Inc., a subsidiary of our General Partner, which we refer to as EES, we are charged for the services of employees resident in the United States. The charges related to these service agreements are included in Operating and administrative expenses on our consolidated statements of income.

Operational Services Agreement

We are charged an amount by the Canadian service providers for services we are provided under the operational services agreement. The amount we are charged is established as part of the annual budget and agreed upon by us and the Canadian service providers. The amount we are charged is computed based on an estimate of the pro-rata reimbursement of each Canadian service provider s estimated annual departmental costs, net of amounts charged to other affiliates and amounts identifiable as costs of that Canadian service provider. The Canadian service providers charge us a monthly fixed fee that is computed as one-twelfth of the annual budgeted amount. Under the operational services agreement, our General Partner and Enbridge Management pay the Canadian service providers a monthly fee determined in the manner described above. At the request of Enbridge Management, the fee for these operational services provided to it in its capacity as the delegate of our General Partner are billed directly to us.

Enbridge Management and our General Partner may request that the Canadian service providers provide special additional operational services for which each, as appropriate, agrees to pay costs and expenses incurred by the Canadian service provider in connection with providing the special additional operational services. The types of services provided under the operational services agreement include:

- Executive, administrative and other services on an as required basis;
- Monitoring transportation capacity, scheduling shipments, standardizing integrity, maintenance and other operational requirements;
- Addressing regulatory matters associated with the liquids pipeline operations;
- Providing monthly measurement information, forecasts, oil accounting, invoicing and related services;
- Computer application development and support services, including liquid pipelines control center operations;
- Electrical power requirements and costs for system operations;
- Patrol and aircraft services; and
- Any other operational services required to operate existing systems and any additional systems acquired by us.

Each year, the Canadian service providers prepare annual budgets by departmental cost center for their respective operations. After establishing a budget for the following year, the costs associated with each department are allocated to us, our General Partner, Enbridge Management and other Enbridge affiliates using one of the following three methods:

- Capital assets employed as a percentage of Enbridge-wide capital assets;

Time-based estimates; or

Full-time-equivalent (FTE)/headcount as a percentage of Enbridge-wide FTEs.

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The total amount we reimbursed the Canadian service providers pursuant to the operational services agreement for the years ended December 31, 2013, 2012 and 2011 was $154.9 million, $133.0 million and $97.3 million, respectively.

General and Administrative Services Agreement

We, Enbridge Management and our General Partner receive services from EES under the general and administrative services agreement. Under this agreement, EES provides services to us, Enbridge Management and our General Partner and charges each recipient for services, on a monthly basis, the actual costs that it incurs for those services. Our General Partner and Enbridge Management may request that EES provide special additional general services for which each, as appropriate, agrees to pay costs and expenses incurred by EES in connection with providing the special additional general services. The types of services provided under the general and administrative services agreement include:

- Accounting, tax planning and compliance services, including preparation of financial statements and income tax returns;
- Administrative, executive, legal, human resources and computer support services;
- Insurance coverage;
- All administrative and operational services required to operate existing systems and any additional systems acquired by us and operated by EES; and
- Facilitate the business and affairs of Enbridge Management and us, including, but not limited to, public and government affairs, engineering, environmental, finance, audit, operations and operational support, safety/compliance and other services.

EES captures all costs that it incurs for providing the services by cost center in its financial system. The cost centers are determined to be Shared Service , Enbridge Energy Partners, L.P. only or Non-Enbridge Energy Partners, L.P. Shared Service cost centers are used to capture costs that are not specific to a single United States Enbridge entity but are shared among multiple United States Enbridge entities. The costs captured in the cost centers that are specific to us are charged in full to us. The costs captured in cost centers that are outside of our business unit are charged to other Enbridge entities.

The general method used to allocate the Shared Service costs is established through the budgeting process and reimbursed as follows:

- Each cost center establishes a budget.
- Each cost center manager estimates the amount of time the department spends on us and entities that are not directly affiliated with us.
- Costs are accumulated monthly for each cost center.
- The actual costs accumulated monthly by each cost center are allocated to us or entities that are not directly affiliated with us based on the allocation model.
- We reimburse EES for its share of the allocated costs.

The total amount reimbursed by us for services received pursuant to the general and administrative services agreement for the years ended December 31, 2013, 2012 and 2011 was $284.1 million, $291.1 million and $264.3 million, respectively.

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of $51.7 million, $33.1 million and $24.9 million during 2013, 2012 and 2011, 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 it and its subsidiaries. In December 2012, the Partnership entered into an insurance allocation agreement with Enbridge and another Enbridge subsidiary, which was amended and restated on November 13, 2013 to add MEP as a party. Under this agreement, 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.

Sale of Accounts Receivable

Certain of our subsidiaries entered into a receivables purchase agreement, dated June 28, 2013, which we refer to as the Receivables Agreement, with an indirect wholly-owned subsidiary of Enbridge. The Receivables Agreement was amended on September 20, 2013 and again on December 2, 2013. The Receivables Agreement and the transactions contemplated thereby were approved by the special committee of the board of directors of Enbridge Management. Pursuant to the Receivables Agreement, the Enbridge subsidiary will purchase on a monthly basis, for cash, current accounts receivable and accrued receivables, or the receivables, of the respective subsidiaries initially up to a monthly maximum of $450.0 million. 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. The Partnership and MEP act in an administrative capacity as collection agents on behalf of the Enbridge subsidiary and can be removed at any time in the sole discretion of the Enbridge subsidiary. The Partnership has 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 Operating and administrative-affiliate expense in our consolidated statements of income. For the year-ended December 31, 2013, the cost stemming from the discount on the receivables sold was not material. For the year-ended December 31, 2013, we sold and derecognized $2,241.5 million of receivables to the Enbridge subsidiary. For the year-ended December 31, 2013, the cash proceeds were $2,235.7 million which was remitted to the Partnership through our centralized treasury system. As of December 31, 2013, $380.1 million of the receivables were outstanding from customers that had not been collected on behalf of the Enbridge subsidiary.

As of December 31, 2013, we have $69.4 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 as of December 31, 2013.

Line 6A and 6B Expense Reimbursement

For the years ended December 31, 2013, 2012 and 2011, we have reimbursed Enbridge $0.5 million, $4.1 million and $7.6 million, respectively, for its assistance with the administration and clean-up efforts for our Line 6A and 6B crude oil releases. For further details related to our Line 6A and 6B crude oil releases, refer to Note 13. *Commitments and Contingences Lakehead Lines 6A and 6B Crude Oil Releases*.

Affiliate Revenues and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale. We also record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates. Included in our results for the years ended December 31, 2013, 2012 and 2011, are operating revenues of $245.9 million, $414.6 million and $354.3 million, respectively, related to these transactions.

Facilities Cost Reimbursement Agreement

In 2007, we entered into an agreement with Enbridge Pipelines to install and operate certain sampling and related facilities for the purpose of improving the quality of crude oil and the transportation services on our Lakehead system, which directly increases the transportation services revenue of Enbridge Pipelines. As compensation for installing and operating these transportation facilities, Enbridge Pipelines makes annual payments to us on a cost of service basis. The income we recorded for providing these transportation services in 2013, 2012 and 2011 was approximately $0.8 million, $0.8 million and $0.8 million, respectively.

We also purchase natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Included in our results for the years ended December 31, 2013, 2012 and 2011, are costs for natural gas purchases of $119.5 million, $285.4 million and $200.8 million, respectively, related to these purchases.

Financing Transactions with Affiliates

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance the construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Pipeline, by issuing a promissory note payable to our General Partner, which we refer to as the A1 Term Note. At such time we also terminated the A1 Credit Agreement. The A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Pipeline that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the Alberta Clipper Pipeline that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline, with the unpaid balance due in 2020. The approved terms for the Alberta Clipper Pipeline are described in the Alberta Clipper United States Term Sheet, which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the Federal Energy Regulatory Commission, or FERC, by the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

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A summary of the cash activity for the A1 Term Note for the years ended December 31, 2013, 2012 and 2011 are as follows:

	A1 Term Note (in millions)
Balance at December 31, 2011	$ 342.0
Repayments	(12.0)
Balance at December 31, 2012	330.0
Borrowings	
Repayments	(12.0)
Balance at December 31, 2013	$ 318.0

The following table presents in millions, the scheduled maturities of the A1 Term Note based upon the $318.0 million outstanding at December 31, 2013.

	(in millions)
2014	$ 12.0
2015	12.0
2016	12.0
2017	12.0
2018	12.0
Thereafter	258.0
Total	$ 318.0

Our General Partner also made equity contributions totaling $3.3 million to the OLP during the year ended December 31, 2011 to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline. There were no similar equity contributions associated with the Alberta Clipper Pipeline for the years ended December 31, 2013 or 2012.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $52.6 million, $53.9 million and $53.2 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the years ended December 31, 2013, 2012 and 2011, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in Net income attributable to noncontrolling interest on our consolidated statements of income.

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Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the years ended December 31, 2013, 2012 and 2011, representing the noncontrolling interest in the Series AC and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount Paid to the noncontrolling interest (in millions)	Total Series AC Distribution
2013				
October 31	November 14	$ 7.0	$ 14.1	$ 21.1
July 29	August 14	5.5	11.0	16.5
April 30	May 15	7.5	14.9	22.4
January 30	February 14	6.9	13.8	20.7
		$ 26.9	$ 53.8	$ 80.7
2012				
October 31	November 14	$ 6.5	$ 12.9	$ 19.4
July 30	August 14	7.2	14.4	21.6
April 30	May 15	8.4	16.8	25.2
January 30	February 14	7.9	15.8	23.7
		$ 30.0	$ 59.9	$ 89.9
2011				
October 28	November 14	$ 7.7	$ 15.3	$ 23.0
July 28	August 12	8.8	17.7	26.5
April 28	May 13	10.8	21.6	32.4
January 28	February 14	10.9	21.8	32.7
		$ 38.2	$ 76.4	$ 114.6

Joint Funding Arrangement for Eastern Access Projects

In May 2012, we amended and restated partnership agreement of the OLP to establish an additional series of partnership interests, which we refer to as the EA interests. The EA interests were created to finance projects to increase access to refineries in the United States Upper Midwest and in Ontario, Canada for light crude oil produced in western Canada and the United States, which we refer to as the Eastern Access Projects. From May 2012 through June 27, 2013, our General Partner indirectly owned 60% all assets, liabilities and operations related to the Eastern Access Projects. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding of the Eastern Access Projects from 40% to 25%. Additionally, within one year of the in-service date, scheduled for early 2016, we have the option to increase our economic interest by up to 15 percentage points. We received $90.2 million from our General Partner in consideration for our assignment to it of this portion of our interest, determined based on the capital we had funded prior to June 28, 2013 pursuant to Eastern Access Projects.

Our General Partner has made equity contributions totaling $609.2 million and $347.9 million to the OLP for the year ended December 31, 2013 and 2012, respectively to fund its equity portion of the construction costs associated with the Eastern Access Projects.

We allocated earnings from the Eastern Access Projects in the amount of $32.1 million to our General Partner for its 60% ownership of the EA interest for the year ended December 31, 2013. We allocated earnings

derived from the Eastern Access Projects in the amount of $3.4 million to our General Partner for the year ended 2012. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Joint Funding Arrangement for the U.S. Mainline Expansion

In December 2012, the OLP further amended and restated its limited partnership agreement to establish another series of partnership interests, which we refer to as the ME interests. The ME interests were created to finance projects to increase access to the markets of North Dakota and western Canada for light oil production on our Lakehead System between Neche, North Dakota and Superior, Wisconsin, which we refer to as our Mainline Expansion Projects. From December 2012 through June 27, 2013, the projects were jointly funded by our General Partner at 60% and the Partnership at 40%, under the Mainline Expansion Joint Funding Agreement, which parallels the Eastern Access Joint Funding Agreement. On June 28, 2013, we and our affiliates entered into an agreement with our General Partner pursuant to which we exercised our option to decrease our economic interest and funding in the projects from 40% to 25%. Additionally, within one year of the in-service date, currently scheduled for 2016, we have the option to increase our economic interest held at that time by up to 15 percentage points. All other operations are captured by the Lakehead interests. We received $12.0 million from our General Partner in consideration for our economic interest.

Our General Partner has made equity contributions totaling $159.9 million and $3.0 million to the OLP for the year ended December 31, 2013 and year ended 2012, respectively to fund its equity portion of the construction costs associated with the U.S. Mainline Expansion Projects.

We allocated earnings from the Mainline Expansion Projects in the amount of $4.3 million to our General Partner for its ownership of the ME interest for the year ended December 31, 2013. We have presented this amount we allocated to our General Partner in Net income attributable to noncontrolling interest on our consolidated statements of income.

Midcoast Energy Partner, L.P.

On November 13, 2013, MEP completed its initial public offering of Class A common units, representing limited partner interests in MEP. On the same date, in connection with the closing of that offering, certain transactions, among others, occurred pursuant to which we effectively conveyed to MEP all of our limited liability company interests in the general partner of the operating subsidiary of MEP, or Midcoast Operating and a 39% limited partner interest in Midcoast Operating, in exchange for certain MEP Class A common units and MEP Subordinated Units, approximately $304.5 million in cash as reimbursement for certain capital expenditures with respect to the contributed businesses, and a right to receive $323.4 million in cash. Also in connection with the closing of that offering, on November 13, 2013, we entered into the following agreements:

Omnibus Agreement

We, Midcoast Holdings, L.L.C., the general partner of MEP (the MEP General Partner), MEP, and Enbridge Inc. (Enbridge), entered in the Omnibus Agreement to which we agreed to indemnify MEP for certain matters, including environmental, right-of-way and permit matters, and we granted MEP a license to use the Enbridge logo and certain other trademarks and tradenames. The Omnibus Agreement may be terminated by the mutual agreement of the parties, or by either Enbridge or MEP in the event that we cease to control the MEP General Partner, provided that our indemnification obligations will remain in full force and effect until they expire in accordance with their respective terms.

Under the Omnibus Agreement, we also agreed to indemnify MEP for all known and certain unknown environmental liabilities that are associated with the ownership or operation of MEP s assets arising prior to the closing of that offering, in each case that are identified prior to the third anniversary of the closing of that offering. Our obligation to indemnify MEP for any environmental liabilities is subject to a $500,000 aggregate deductible before MEP is entitled to indemnification. We will also indemnify MEP for failure to have certain rights-of-way, consents, licenses and permits necessary to own and operate its assets in substantially the same manner in which they were owned and operated prior to the closing of the Offering, including the cost of curing certain such failures that do not allow its assets to be operated in accordance with prudent industry practice, in each case that are identified prior to the third anniversary of the closing of the Offering. Our obligation to indemnify MEP for any right-of-way, consent, license or permit matters will be subject to a $500,000 aggregate deductible before MEP is entitled to indemnification. There will be a $15 million aggregate cap on the amounts for which we will indemnify MEP for environmental, right-of-way, consents, licenses and permit matters under the Omnibus Agreement.

Intercorporate Services Agreement

We entered into an Intercorporate Service Agreement (the Intercorporate Services Agreement) with MEP, pursuant to which we will provide MEP with the following services:

- executive, management, business development, administrative, legal, human resources, records and information management, public affairs, investor relations, government relations and computer support services;

- accounting and tax planning and compliance services, including preparation of financial statements and income tax returns, unitholder tax reporting and audit and treasury services;

- strategic insurance advice, planning and claims management and related support services, and arrangement of insurance coverage as required;

- facilitation of capital markets access and financing services, cash management and related banking services, financial structuring and advisory services, as well as credit support for MEP s subsidiaries and affiliates on an as-needed basis for projects, transactions or other purposes;

- operational and technical services, including integrity, safety, environmental, project management, engineering, fundamentals analysis and regulatory, and pipeline control and field operations; and

- such other services as MEP may request.

Under the Intercorporate Services Agreement, MEP will reimburse the Partnership and its affiliates for the costs and expenses incurred in providing such services to MEP; however, we have 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.

Financial Support Agreement

We entered into a Financial Support Agreement with Midcoast Operating (the Financial Support Agreement), pursuant to which we 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, our support of Midcoast Operating s and its wholly owned subsidiaries obligations will terminate on the earlier to occur of (1) November 13, 2017 and (2) the date on which EEP owns, directly or indirectly (other than through its ownership interests in MEP), less than 20% of the total outstanding limited partner interests in Midcoast Operating.

The Financial Support Agreement also provides that if MEPs bank credit agreement is secured, the Financial Support Agreement also will be secured to the same extent on a second-lien basis. We also have agreed to subordinate our right to payment on obligations owed under the Financial Support Agreement and Working Capital Credit Facility (defined below) and liens, if secured, to the rights of the lenders under the MEP credit agreement.

Amended and Restated Allocation Agreement

On November 13, 2013, in connection with the closing of the Offering, MEP entered into an Amended and Restated Allocation Agreement (the Insurance Allocation Agreement), by and among MEP, Enbridge, EEP and Enbridge Income Fund Holdings Inc., in order to participate in the comprehensive insurance program that is maintained by Enbridge for it and its subsidiaries. Under the Insurance Allocation Agreement, in the unlikely event that multiple insurable incidents occur that exceed coverage limits within the same insurance period, the total insurance coverage available to Enbridge and its subsidiaries under the insurance program will be allocated among the participating Enbridge entities on an equitable basis.

Working Capital Credit Facility

We entered into a $250.0 million Working Capital Loan Agreement (the Working Capital Credit Facility), by and between Midcoast Operating, as borrower, and the Partnership, as lender. The facility is available exclusively to fund Midcoast Operating working capital borrowings. Borrowings under the facility are scheduled to mature on November 13, 2017 and accrue interest at a per annum rate of LIBOR plus 2.5%. The Partnership s commitment to lend pursuant to the Working Capital Credit Facility will end on the earlier of the facility s maturity (by acceleration or otherwise) and the date on which we own less than 20% of the outstanding limited partner interests in Midcoast Operating. If our commitment to lend has terminated before the facility has matured (by acceleration or otherwise), then the aggregate amount of all outstanding borrowings under the facility will automatically convert to a term loan that will bear interest at LIBOR (calculated as of the conversion date) plus 2.5%. Midcoast Operating has agreed to pay a commitment fee on the unused commitment at a per annum rate of 0.4250%, payable each fiscal quarter.

General Partner Equity Transactions

Our General Partner owns an effective 2% general partner interest in us. Pursuant to our partnership agreement we paid cash distributions to our General Partner of $139.3 million, $122.3 million and $95.0 million for the years ended December 31, 2013, 2012, and 2011, respectively. The cash distributions we make to our General Partner exclude an amount equal to 2% of the i-units and until the conversion to Class A common units, the Class C unit distributions, which we retain from the General Partner to maintain its 2% general partner interest in us.

As of December 31, 2013 and 2012, our General Partner owned 46,518,336 Class A common units, representing a 14.0% and 16.0% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $101.1 million, $100.1 million and $97.3 million for the years ended December 31, 2013, 2012 and 2011, respectively, with respect to its ownership of Class A common units.

As of December 31, 2013 and 2012, our General Partner also owned 7,825,500 Class B common units, representing a 2.4% and 2.5% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $17.0 million, $16.8 million and $16.4 million for the years ended December 31, 2013, 2012, and 2011, respectively, with respect to its ownership of Class B common units.

As of December 2013, our General Partner also owned 48,000,000 Series 1 Preferred Units, representing limited partner interests in the partnership.

For further discussion of these and other related party transactions, refer to Note 12. *Related Party Transactions* in the consolidated financial statements of this Annual Report on Form 10-K.

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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 or Enbridge Management, 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 Enbridge Management and 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.

During 2013, 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 Jan Connelly, the sister of Jeffrey A. Connelly, a member of the Board of Directors. Ms. Connelly is employed in our Houston office as an Optimization Advisor. During 2013, she received total cash compensation of $216,926.41 and benefits estimated at approximately 32% of her base compensation for a total of $260,373.87.

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 member of the Board of Directors. Mr. McGill is employed in our Houston office as a Gas Supply Representative. During 2013, he received total cash compensation of $97,172.29 and benefits estimated at approximately 32% of his base compensation for a total of $123,822.49.

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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, 2013	2012
Audit fees[(1)]	$ 6,385,000	$ 3,894,000
Tax fees[(2)]	755,000	775,500
Total	$ 7,140,000	$ 4,669,500

(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.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit Committee of Enbridge Management s board of directors; however, services up to $50,000 may be approved by the Chairman of the Audit Committee, under the board of directors delegated authority. All services in 2013 and 2012 were approved by the Audit 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* beginning on page 133 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, 2013, 2012 and 2011.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011.

e. Consolidated Statements of Financial Position as of December 31, 2013 and 2012.

f. Consolidated Statements of Partners Capital for the years ended December 31, 2013, 2012 and 2011.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

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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 on page 266, which is hereby incorporated into this Item.

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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.

ENBRIDGE ENERGY PARTNERS, L.P.

(Registrant)

By: Enbridge Energy Management, L.L.C.,

as delegate of the General Partner

By: /s/ Mark A. Maki
Mark A. Maki
(President and Principal Executive Officer)

Date: February 18, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 18, 2014 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ Mark A. Maki Mark A. Maki *President, Principal Executive Officer and* *Director*	/s/ Terrance L. McGill Terrance L. McGill *Senior Vice President and* *Director*
/s/ Stephen J. Wuori Stephen J. Wuori *Executive Vice President Liquids* *Pipelines and Director*	/s/ J. Richard Bird J. Richard Bird *Director*
/s/ Stephen J. Neyland Stephen J. Neyland *Vice President Finance* *(Principal Financial Officer)*	/s/ C. Gregory Harper C. Gregory Harper *Director*
/s/ Noor S. Kaissi Noor S. Kaissi *Controller*	/s/ Jeffrey A. Connelly Jeffrey A. Connelly *Director*
/s/ J. Herbert England J. Herbert England *Director*	/s/ Dan A. Westbrook Dan A. Westbrook *Director*

/s/ Rebecca B. Roberts
Rebecca B. Roberts

Director

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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 the Partnership (incorporated by reference to Exhibit 3.1 of our Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 of our Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed on August 16, 2006).
3.4	Amendment No. 1 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on January 3, 2008).
3.5	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 6, 2008 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 7, 2008).
3.6	Amendment No. 3 to Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated April 21, 2011 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on April 25, 2011).
3.7	Fifth Amended and Restated Agreement of Limited Partnership of the Partnership, dated May 8, 2013 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K, filed on May 13, 2013).
4.1	Form of Certificate representing Class A common units (incorporated by reference to Exhibit 4.1 of our Amendment to Annual Report on Form 10-K/A for the year ended December 31, 2000, filed on October 9, 2001).
4.2	Registration Rights Agreement, dated April 2, 2007, among Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P., Tortoise Energy Infrastructure Corporation and Tortoise Energy Capital Corporation (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed on April 2, 2007).
4.3	Series 1 Preferred Unit Purchase Agreement, dated May 7, 2013 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on May 13, 2013).
10.1	Intercorporate Services Agreement, dated as of November 13, 2013, by and between Midcoast Energy Partners, L.P. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on November 19, 2013).
10.2	Financial Support Agreement, dated as of November 13, 2013, by and between Midcoast Operating, L.P. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on November 19, 2013).
10.3	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership (incorporated by reference to Exhibit 10.1 of our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 19, 2009).

Exhibit Number	Description
10.4	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership (incorporated by reference to Exhibit 10.2 of our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 19, 2009).
10.5	Contribution Agreement (incorporated by reference to Exhibit 10.1 of our Registration Statement on Form S-3/A, filed on July 8, 2002).
10.6	First Amendment to Contribution Agreement (incorporated by reference to Exhibit 10.8 of our Registration Statement on Form S-1/A, filed on September 24, 2002).
10.7	Second Amendment to Contribution Agreement (incorporated by reference to Exhibit 99.3 of our Current Report on Form 8-K, filed on October 31, 2002).
10.8	Contribution Agreement among Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C., the OLP, the Partnership, Enbridge Pipelines (Lakehead) L.L.C. and Enbridge Pipelines (Wisconsin) Inc. dated July 17, 2009 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on July 22, 2009).
10.9	Contribution Agreement among Enbridge Energy Company, Inc., Enbridge Pipelines (Eastern Access) L.L.C., the OLP, the Partnership, and Enbridge Pipelines (Lakehead) L.L.C. dated May 17, 2012 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on May 18, 2012).
10.10	Contribution Agreement among Enbridge Energy Company, Inc., Enbridge Pipelines (Mainline Expansion) L.L.C., the OLP, the Partnership, and Enbridge Pipelines (Lakehead) L.L.C. dated December 6, 2012 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on December 6, 2012).
10.11	Contribution, Conveyance and Assumption Agreement, dated as of November 13, 2013, by and among Enbridge Energy Partners, L.P., Midcoast Energy Partners, L.P., Midcoast Holdings, L.L.C., Midcoast Operating, L.P. and Midcoast OLP GP, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on November 19, 2013).
10.12	Third Amended and Restated Agreement of Limited Partnership of the OLP among Enbridge Pipelines (Lakehead) L.L.C., Enbridge Pipelines (Wisconsin) Inc., Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C. and the Partnership dated July 31, 2009 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on August 5, 2009).
10.13	Fourth Amended and Restated Agreement of Limited Partnership of the OLP among Enbridge Pipelines (Lakehead) L.L.C., Enbridge Pipelines (Wisconsin) Inc., Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C., Enbridge Pipelines (Eastern Access) L.L.C., and the Partnership dated May 17, 2012 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on May 18, 2012).
10.14	Fifth Amended and Restated Agreement of Limited Partnership of the OLP among Enbridge Pipelines (Lakehead) L.L.C., Enbridge Pipelines (Wisconsin) Inc., Enbridge Energy Company, Inc., Enbridge Pipelines (Alberta Clipper) L.L.C., Enbridge Pipelines (Eastern Access) L.L.C., Enbridge Pipelines (Mainline Expansion) L.L.C. and the Partnership dated December 6, 2012 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on December 6, 2012).
10.15	First Amending Agreement to the Delegation of Control Agreement, dated February 21, 2005 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q, filed on May 5, 2005).
10.16	Amended and Restated Treasury Services Agreement (incorporated by reference to Exhibit 10.3 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).

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Exhibit Number	Description
10.17	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.18	General and Administrative Services Agreement (incorporated by reference to Exhibit 10.5 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.19	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.20	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 Current Report on Form 8-K, filed on November 19, 2013).
10.21	Commercial Paper Dealer Agreement between the Partnership, as Issuer, and Banc of America Securities LLC, as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on May 3, 2005).
10.22	Commercial Paper Dealer Agreement between the Partnership, as Issuer, and Deutsche Bank Securities Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on May 3, 2005).
10.23	Commercial Paper Dealer Agreement between the Partnership, as Issuer, and Goldman, Sachs & Co., as Dealer, dated April 21, 2005 (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K, filed on May 3, 2005).
10.24	Commercial Paper Dealer Agreement between the Partnership, as Issuer, Merrill Lynch, Pierce, Fenner, and Smith Incorporated and Merrill Lynch Money Markets Inc., as Dealer, dated April 21, 2005 (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K, filed on May 3, 2005).
10.25	Commercial Paper Issuing and Paying Agent Agreement between the Partnership and Deutsche Bank Trust Company Americas, dated April 21, 2005 (incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K, filed on May 3, 2005).
10.26	Commercial Paper Issuing and Paying Agent Agreement between the Partnership and Citigroup Global Markets Inc., dated December 15, 2010 (incorporated by reference to Exhibit 10.20 of our Annual Report on Form 10-K for the year ended December 31, 2010, filed on February 18, 2011).
10.27	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (incorporated by reference to Exhibit 10.19 of our Annual Report on Form 10-K for the year ended December 31, 2008, filed on February 19, 2009).
10.28	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy (incorporated by reference to Exhibit 10.17 of our 1996 Annual Report on Form 10-K for the year ended December 31, 1996, filed on February 28, 1997).
10.29	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program Phase II and Terrace Expansion Project (incorporated by reference to Exhibit 10.21 of our Annual Report on Form 10-K for the year ended December 31, 1998, filed on March 22, 1999).
10.30	Offer of Settlement, dated December 21, 2005, as filed with the Federal Energy Regulatory Commission for approval to implement an additional component of the Facilities Surcharge to permit recovery by Enbridge Energy, Limited Partnership of the costs for the Southern Access Mainline Expansion and approval of the Offer of Settlement dated March 16, 2006 (incorporated by reference to Exhibit 10.3 of our Quarterly Report on Form 10-Q, filed on July 31, 2007).
*+10.31	Executive Employment Agreement, entered into February 11, 2014, between C. Gregory Harper, the Executive, and Enbridge Employee Services, Inc., effective January 30, 2014.

Exhibit Number	Description
+10.32	Executive Employment Agreement, dated December 20, 2012, between Leon Zupan, the Executive, and Enbridge Inc., the company effective August 1, 2012. (incorporated by reference to Exhibit 10.1 on Form 10-K for the year ended December 31, 2012, filed on February 15, 2013).
+10.33	Executive Employment Agreement between Stephen J. Wuori and Enbridge Inc., dated April 14, 2003, (incorporated by reference to our Current Report on Form 8-K, filed on January 28, 2008).
+10.34	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.27 of our Annual Report on Form 10-K, filed on March 28, 2003).
+10.35	Enbridge Incentive Stock Option Plan (2002), dated May 3, 2002 (incorporated by reference to Exhibit 10.2 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).
+10.36	Enbridge Incentive Stock Option Plan (2007) dated January 1, 2007 (incorporated by reference to Exhibit 10.3 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).
+10.37	Enbridge Performance Stock Option Plan (2007) dated January 1, 2007 (incorporated by reference to Exhibit 10.4 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).
+10.38	Enbridge Performance Stock Option Plan (2007), amended and restated in 2011, further amended November 2012 (incorporated by reference to Exhibit 10.40 of our Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 15, 2013).
+10.39	Enbridge Performance Stock Unit Plan (2007), dated January 1, 2007 (incorporated by reference to Exhibit 10.5 or our Quarterly Report on Form 10-Q, filed on July 27, 2009).
+10.40	Enbridge Performance Stock Unit Plan (2007), as amended November 2012 (incorporated by reference to Exhibit 10.40 of our Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 15, 2013).
10.41	Indenture, dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.5 of our Registration Statement on Form S-4, filed on June 30, 2003).
10.42	Second Supplemental Indenture, dated May 27, 2003, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.7 of our Registration Statement on Form S-4, filed on June 30, 2003).
10.43	Fourth Supplemental Indenture, dated December 3, 2004, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on December 3, 2004).
10.44	Fifth Supplemental Indenture, dated December 3, 2004, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K, filed on December 3, 2004).
10.45	Sixth Supplemental Indenture, dated December 21, 2006, between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on December 21, 2006).
10.46	Seventh Supplemental Indenture, dated April 3, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on April 7, 2008).
10.47	Eighth Supplemental Indenture, dated April 3, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K, filed on April 7, 2008).
10.48	Ninth Supplemental Indenture, dated December 22, 2008, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on December 22, 2008).
10.49	Tenth Supplemental Indenture, dated March 2, 2010, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership s Current Report on Form 8-K, filed on March 2, 2010).

Exhibit Number	Description
10.50	Eleventh Supplemental Indenture, dated September 13, 2010, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership s Current Report on Form 8-K, filed on September 13, 2010).
10.51	Twelfth Supplemental Indenture, dated September 15, 2011, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership s Current Report on Form 8-K, filed on September 15, 2011).
10.52	Indenture for Subordinated Debt Securities, dated September 27, 2007, between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K, filed on September 28, 2007).
10.53	First Supplemental Indenture to the Indenture, dated September 27, 2007, between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (including form of Note) (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K, filed on September 28, 2007).
10.54	Replacement Capital Covenant, dated September 27, 2007, by Enbridge Energy Partners, L.P. in favor of the debt holders designated therein (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on September 28, 2007).
10.55	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of our Current Report on Form 8-K, filed on February 10, 2005).
10.56	Class A Common Unit Purchase Agreement, dated November 17, 2008, between the Partnership and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on November 18, 2008).
10.57	International Joint Tariff Agreement, dated May 6, 2011, by and between Enbridge Pipelines Inc. and Enbridge Energy, Limited Partnership (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on June 29, 2011).
10.58	A1 Credit Agreement between the Partnership, as Borrower, and Enbridge Energy Company, Inc., as Lender, dated July 31, 2009 (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on August 5, 2009).
10.59	Commercial Paper Dealer Program [4(2) Program] dated as of December 15, 2010 between the Partnership, as Issuer, and Citigroup Global Markets Inc., as Dealer (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K, filed on February 18, 2011).
10.60	Credit Agreement, dated September 26, 2011, between the Partnership, as Borrower, and Bank of America, N.A., as Administrative Agent and the other lenders a party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on September 29, 2011).
10.61	First Amendment to Credit Agreement, dated as of September 30, 2011, between the Partnership, as Borrower, the lenders parties thereto, and Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q, filed on November 1, 2012).
10.62	Extension Agreement and Second Amendment to Credit Agreement, as of September 26, 2012, between the Partnership, as Borrower, the lenders parties thereto, and Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q, filed on November 1, 2012).
10.63	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, 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 to our of our Current Report on Form 8-K, filed on November 19, 2013).

Exhibit Number	Description
10.64	Subordination Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., Midcoast Operating, L.P., the other credit parties from time to time party thereto, Enbridge Energy Partners, L.P. and Bank of America, N.A. (incorporated by reference to Exhibit 10.8 to our of our Current Report on Form 8-K, filed on November 19, 2013).
10.65	Working Capital Loan Agreement, dated as of November 13, 2013, by and between Midcoast Operating, L.P. and Enbridge Energy Partners, L.P. (incorporated by reference to Exhibit 10.7 to our of our Current Report on Form 8-K, filed on November 19, 2013).
10.66	Allocation Agreement, dated December 31, 2012, by and between Enbridge Inc., the Partnership and Enbridge Income Fund Holdings Inc., (incorporated by reference to Exhibit 10.70 of our Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 15, 2013).
10.67	Amended and Restated Allocation Agreement, dated as of November 13, 2013, by and among Midcoast Energy Partners, L.P., Enbridge Inc., Enbridge Energy Partners, L.P. and Enbridge Income Fund Holdings Inc. (incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K, filed on November 19, 2013).
10.68	Amended and Restated Limited Liability Company Agreement of North Dakota Pipeline Company LLC, dated as of November 25, 2013, by and between Enbridge Energy Partners, L.P. and Williston Basin Pipe Line LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K, filed on December 2, 2013).
10.69	Operating and Construction Management Agreement, dated as of November 25, 2013, by and between North Dakota Pipeline Company LLC and Enbridge (U.S.) Inc. (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K, filed on December 2, 2013).
10.70	Credit Agreement dated as of July 6, 2012, by and among the Partnership, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on February 14, 2013).
10.71	Amendment No. 1 to Credit Agreement, dated as of February 8, 2013, by and among the Partnership, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on February 14, 2013).
10.72	Amendment No. 2 to Credit Agreement and Extension and Increase Agreement, dated as of July 3, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on July 5, 2013).
10.73	Option Interests Purchase Agreement, dated as of June 28, 2013, between Enbridge Energy Partners, L.P. and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on July 5, 2013).
10.74	Form of Indemnification Agreement, and Schedule of Omitted Agreements (incorporated by reference to Exhibit 10.6 of our Quarterly Report on Form 10-Q/A, filed on August 6, 2013).
10.75	Form of Guarantee, and Schedule of Omitted Agreement (incorporated by reference to Exhibit 10.7 of our Quarterly Report on Form 10-Q/A, filed on August 6, 2013).
10.76	Registration Rights Agreement, dated as of May 7, 2013, by and between the Partnership and Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K, filed on May 13, 2013).
10.77	Incremental Commitment Activation Notice to Credit Agreement, dated July 24, 2013, between the Partnership, the Borrower, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.8 of our Quarterly Report on Form 10-Q, filed on July 31, 2013).

Exhibit Number	Description
10.78	New Lender Supplement to Credit Agreement, dated July 24, 2013, between the Partnership, the Borrower, JP Morgan Chase Bank, National Association, as administrative agent for the lenders, letter of credit issuer, swing line lender and lender and the other lenders from time to time parties thereto (incorporated by reference to Exhibit 10.8 of our Quarterly Report on Form 10-Q, filed on July 31, 2013).
10.79	Extension Agreement and Third Amendment to Credit Agreement, dated as of October 28, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q, filed on October 31, 2013).
10.80	Amendment No. 3 to Credit Agreement, dated as of October 28, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q, filed on October 31, 2013).
*10.81	Amendment No. 4 to Credit Agreement, dated as of December 23, 2013, by and among Enbridge Energy Partners, L.P., the lenders parties thereto and JPMorgan Chase Bank, National Association, as administrative agent.
*10.82	Fourth Amendment to Credit Agreement, dated as of December 23, 2013, Enbridge Energy Partners, L.P., the lenders parties thereto and Bank of America, N.A., as Administrative Agent.
14.1	Code of Ethics for Senior Financial Officers (incorporated by reference to Exhibit 14.1 of our Annual Report on Form 10-K, filed on March 12, 2004).
*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.
*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.
99.1	Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C. (incorporated by reference to Exhibit 99.1 of our Annual Report on Form 10-K, filed February 25, 2005).

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, Texas 77002.