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

FORM 10-K

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

For the fiscal year ended December 31, 2012

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 ☒ No ☐

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

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

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

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

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

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

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

The aggregate market value of the registrant's Class A common units held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2012, was $5,893,123,201.

As of February 14, 2013 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. 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 Lines 6A and 6B; (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, or 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
AIDC	Allowance for interest during 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
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
ERCB	Energy Resource Conservation Board, a successor regulatory body to the Alberta Energy Utility Board
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
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
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
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
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

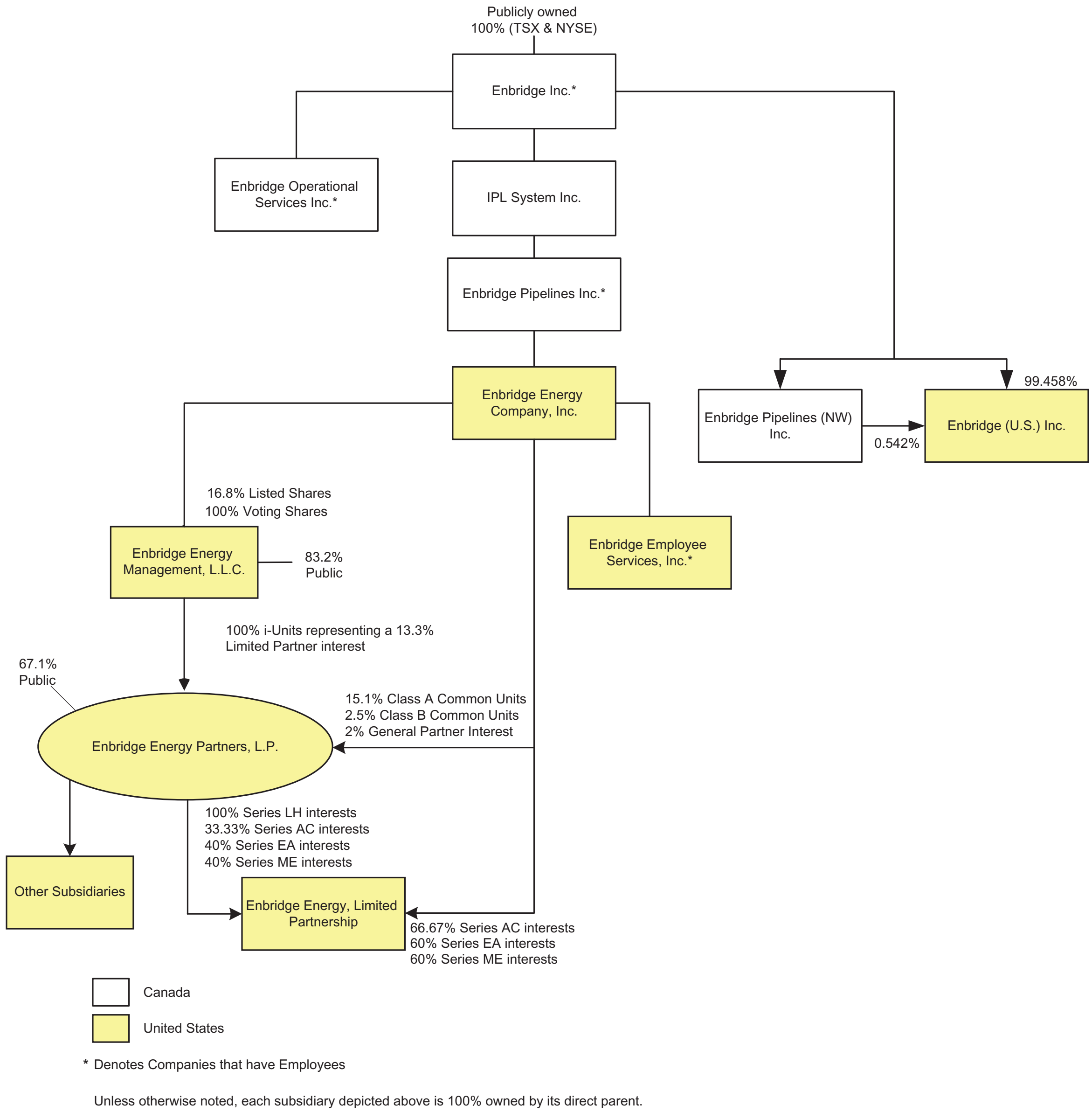
PART I

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, 2012. The ownership percentages referred to below illustrate the relationships between us, Enbridge Management, our General Partner and Enbridge and its affiliates:



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, 2012, our portfolio of assets included the following:

- Approximately 6,500 miles of crude oil gathering and transportation lines and 35 million barrels, or MMBbl, of crude oil storage and terminaling capacity;
- Natural gas gathering and transportation lines totaling approximately 11,400 miles;
- Eight active natural gas treating plants and 25 active natural gas processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants, with a total aggregate capacity of approximately 3,105 million cubic feet per day, or MMcf/d, and plants we may idle from time to time based on current volumes;
- Trucks, trailers and railcars for transporting natural gas liquids, or NGLs, crude oil and carbon dioxide; 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.

BUSINESS STRATEGY

Our primary objective is to provide stable and sustainable cash distributions to our unitholders, 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 the 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.

Liquids

The map below presents the locations of our current Liquids systems' assets and projects being constructed. This map depicts some 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 2012, 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 2012 from the United States Department of Energy's Energy Information Administration, or EIA, Canada supplied approximately 2.4 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, which we refer to as CAPP, in their June 2012 forecast of future production from the Alberta Oil Sands, continued to expect steady growth in supply during the next 18 years with an additional 3.4 million Bpd of incremental supply available 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 Alberta Oil Sands to our existing and new markets.

North Dakota, Montana and Saskatchewan, Canada have 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 August 2012 by the EIA showed 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 that the proved reserve base is substantially higher than what the EIA published.

Along with Enbridge, we are actively working with our customers to develop 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 growing production of North Dakota and western Canada light oil production. Together, our existing and future plans advance our vision of being North America's first choice for liquids deliveries.

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. One of the projects involves the expansion of our Line 5 light crude line between Superior, Wisconsin and Sarnia, Ontario by 50,000 Bpd. Complementing the Line 5 expansion, Enbridge announced plans to reverse portions of its Line 9A and Line 9B in western Ontario to permit crude oil movements eastbound from Sarnia to Westover, Ontario and as far as Montreal, Quebec. The Line 5 expansion is targeted to be in service during the first quarter of 2013, and the Line 9A and Line 9B reversal is targeted to be in service in late 2013 and in 2014, respectively. In May 2012, we and Enbridge announced further plans to expand access to Eastern markets. The projects pursued by the Partnership include: (1) expansion of the Spearhead North pipeline, or Line 62, between Flanagan, Illinois and the Terminal at Griffith, Indiana by adding horsepower to increase capacity from 130,000 Bpd to 235,000 Bpd, and an additional 330,000 barrel crude oil tank at Griffith; and (2) replacement of additional sections of the Partnership's Line 6B in Indiana and Michigan to increase capacity from 240,000 Bpd to 500,000 Bpd. Portions of the existing 30-inch diameter pipeline will be replaced with 36-inch diameter pipe. Subject to customary regulatory approvals, these projects are expected to be placed in-service during 2013 and 2014. These projects are collectively referred to as the Eastern Access Projects.

In December 2012, we and Enbridge also announced 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. Additionally, 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. Additionally, the capacity of our Southern Access pipeline, or Line 61, will be expanded to its full 1,200,000 Bpd potential with additional tankage requirements. Some of the overall expansion is expected to begin service in mid-2015, with additional tankage expected to be completed in 2016.

In North Dakota, oil production levels rose to approximately 733,000 Bpd by December 2012 an approximate 37% increase since December 2011. Capitalizing on this growth, we continue to develop options to access key refinery markets for the Bakken region. Our Bakken Pipeline Expansion, Bakken Access Program and Berthold Rail Project are all projects that will allow Bakken crude oil further access to markets. For further discussion on these projects see BUSINESS SEGMENTS—*North Dakota System* in this Item.

A key strength of the Partnership is our relationship with Enbridge. Enbridge has announced two major United States Gulf Coast market access pipeline projects and their Southern Access Extension Project, which when completed will pull more volume through the Lakehead system.

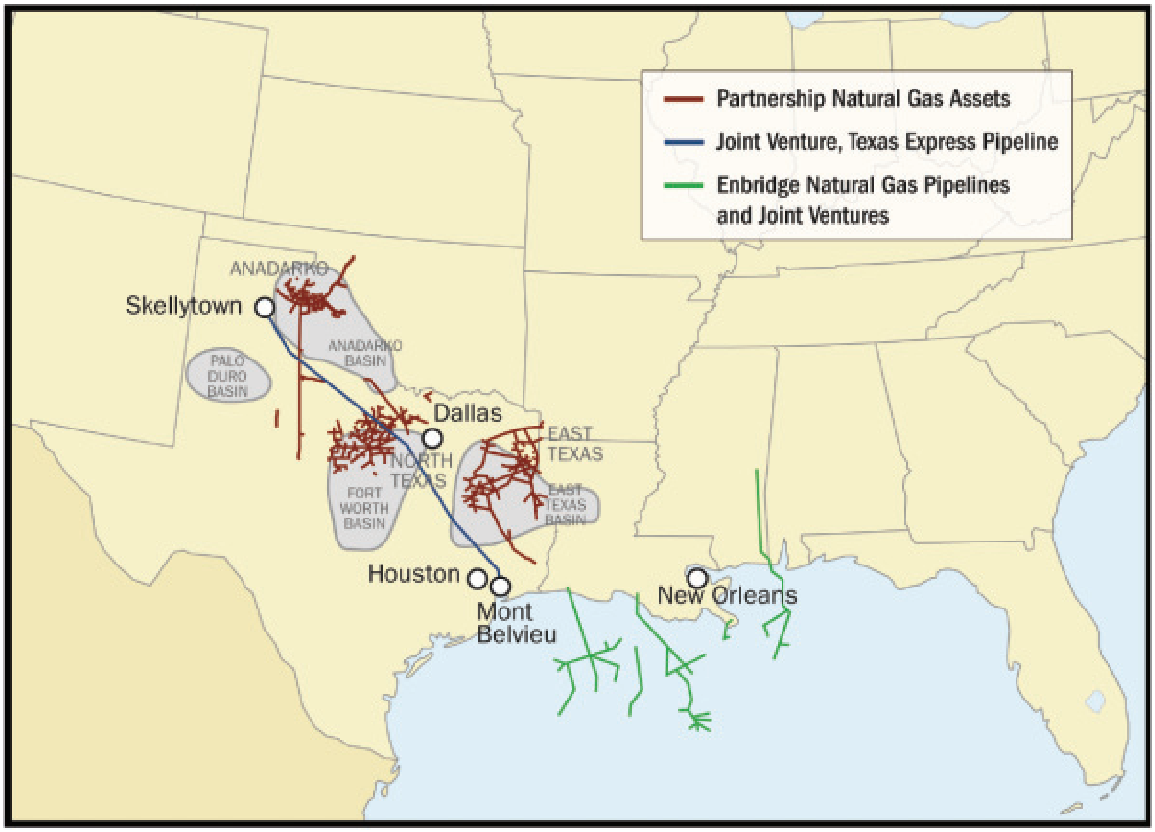
- Enbridge's Flanagan South Pipeline project will transport more volumes into Cushing, Oklahoma and twin its existing Spearhead pipeline, which starts at the hub in Flanagan, Illinois and delivers volumes into the Cushing hub. The 36-inch diameter pipeline will have an initial capacity of approximately 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 is 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 which serves refineries in Houston and Texas City areas. In the second quarter of 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 to approximately 400,000 Bpd, depending upon the mix of light and heavy grades of crude oil. In addition, in March 2012, plans were announced to construct an 85-mile pipeline from Enterprise Product's ECHO Terminal to a Port Arthur/Beaumont, Texas refining center, which will offer incremental capacity of 560,000 Bpd and is expected to be available in mid-2014.

- Southern Access Extension—In December 2012, Enbridge announced a binding open season to solicit commitments from shippers for capacity on the proposed Southern Access Extension pipeline to be constructed, owned and operated by a U.S. subsidiary. The pipeline will transport crude oil from Pontiac, Illinois at Enbridge's Flanagan Terminal where it will receive crude oil from the Lakehead System to Patoka, Illinois. The 165-mile, 24-inch diameter, crude oil pipeline is expected to be placed into service in 2015, subject to regulatory approval.

Natural Gas

The map below presents the locations of our current Natural Gas systems assets' and projects being constructed, including joint ventures. 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 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 producers focusing 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 incenting 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 118 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 seven 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 1,200,000 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 3.4 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 1,900 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 61 pump station locations with a total of approximately 900,000 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 in excess of 55 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 2012, approximately 42 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 3.1 million Bpd in 2012 and 2.8 million in 2011. Meanwhile, strong production growth from the Bakken formation has increased tight oil available from North Dakota to nearly 570,000 Bpd in 2012, as compared to 380,000 Bpd in 2011. 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 169 billion barrels according to the Energy Resources Conservation Board, or ERCB. Additionally, remaining established conventional oil reserves in Western Canada were estimated to be approximately 3.2 billion barrels at the end of 2012. Canada’s total combined conventional and oil sands estimated proved reserves of approximately 175 billion barrels at the end of 2011 compares with Saudi Arabia’s estimated proved reserves of approximately 265 billion barrels.

According to CAPP, an estimated total $262 billion Canadian dollars, or CAD, has been spent on oil sands development from 1997 through 2010. 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 2012 Growth Forecast estimates that the future production from the Alberta Oil Sands is expected to grow steadily during the next 18 years, with an additional 3.4 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 2012 delivered production of four major Alberta Oil Sands producers is detailed as follows:

1. Synthetic production from one of Suncor Energy Inc.'s, or Suncor's, upgraders with a capacity of approximately 350,000 Bpd, averaged approximately 324,000 Bpd in 2012, which was 19,000 Bpd higher than in 2011, and consistent with Suncor's annual target. Suncor completed its Firebag Stage 3 expansion in the first quarter of 2012 thereby allowing the targeted increase in the production of bitumen of approximately 62,500 Bpd, over the following 18 month period. Since Firebag Stage 3 is now complete, Suncor intends to shift its focus to Firebag Stage 4, which has the same expected production capacity and has an expected in-service date in early 2013. In 2011, Suncor announced its strategic partnership with Total E&P Canada, which will enable both companies to jointly develop the Joslyn and Fort Hills oil sands mining projects, as well as resume construction on the Voyageur upgrader.

2. Syncrude Canada Ltd.'s, or Syncrude's, synthetic production in 2012 averaged 286,500 Bpd, matching production levels in 2011. 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 will 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.

3. In September 2012, Cenovus began production at Phase D of its Christina Lake Project. Phase D is expected to yield an additional 40,000 Bpd of production and brings the project's production capacity up to 98,800 Bpd at the end of 2012. Construction of Phase E is on schedule for a fourth quarter 2013 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 300,000 Bpd.

4. Imperial Oil's Kearl Lake oil sands project is expected to start up in early 2013. Initial production will ramp up to approximately 110,000 Bpd. First production had originally been slated for fourth quarter 2012, however was pushed back due to weather delays. 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 open-pit 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 Suncor's North Steepbank Extension, Athabasca Oil Corporation's Hangingstone and Canadian Natural Resources' Kirby South. Based on the CAPP Production forecast, unblended bitumen production is expected to increase by roughly 264,000 Bpd by the end of 2013 and then increase by an additional 163,000 Bpd by the end of 2014.

Although the crude oil and liquid petroleum delivered through our Lakehead system originates primarily in oilfields in Western Canada, our Lakehead system also receives approximately 8% 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 Unites States domestic supply mix. Conservative estimates from the United States Energy Information Administration expects production to reach 800,000 Bpd by 2015 and over 1 million Bpd by 2021.

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 average approximately 2 million Bpd in 2013, which is 200,000 Bpd higher than the 1.8 million Bpd of actual deliveries in 2012. 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, 2012 demand for crude oil in PADD II averaged 3.5 million Bpd, an increase of 78,000 Bpd from 2011. At the same time, production of crude oil within PADD II increased by 264,000 Bpd to 1.1 million Bpd.

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) and the United States Gulf Coast (PADD III). 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 2012, the latest data available shows that PADD II total demand was 3.5 million Bpd while it produced only 1.1 million Bpd and thus imported 2.4 million Bpd from Canada and other regions of the United States. The 2012 data indicates PADD II imported approximately 1.7 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 2012 were approximately 90,000 Bpd higher than delivery volumes for 2011. Total deliveries from our Lakehead system averaged just under 1.8 million Bpd in 2012, meeting approximately 88% of the refinery capacity in the greater Chicago area; 80% of the Minnesota refinery capacity; and 80% of Ontario refinery demand in 2012.

Considering all of the transportation systems that transport crude oil out of Canada, the Mainline system transported over half of all Canadian crude oil imports to the United States in 2012. The remaining production was transported by systems serving the British Columbia, PADD II, PADD IV and PADD V markets. There are a number of smaller competing pipelines located in PADD IV that transport Canadian crude oil into production facilities within the United States. However, the production facilities located within the Rocky Mountain states have significantly less refining capacities in relation to the facilities we serve that are located within the Midwest region of the United States.

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 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 an emerging 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. The Northern Gateway Pipeline has an expected in-service date in the 2018 timeframe, depending on the length of the regulatory review process. 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 proposed 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 extension 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. The construction of the extension 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, which may be received as early as March 2013.

- 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 expected to be 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 660,000 Bpd. A final decision on this expansion is expected by the end of March 2013.

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

The following table sets forth average deliveries per day and barrel miles of our Lakehead system for each of the periods presented.

	2012	2011	2010	2009	2008
	(thousands of Bpd)				
United States					
Light crude oil	521	473	458	467	388
Medium and heavy crude oil	879	850	841	834	876
NGL	5	4	3	4	3
Total United States	1,405	1,327	1,302	1,305	1,267
Ontario					
Light crude oil	228	220	223	197	183
Medium and heavy crude oil	85	84	57	73	80
NGL	72	69	73	75	90
Total Ontario	385	373	353	345	353
Total Deliveries	1,790	1,700	1,655	1,650	1,620
Barrel miles (billions per year)	480	450	439	423	432

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 and El Dorado, Kansas. Our Mid-Continent system includes over 435 miles of crude oil pipelines and 20.5 million barrels of crude oil storage capacity. 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 105 individual storage tanks ranging in size from 55,000 to 575,000 barrels with three new tanks under various stages of construction that will add 936,000 barrels of incremental shell capacity for service during 2013. Of the 20.5 million barrels of storage shell capacity on our Mid-Continent system, the Cushing terminal accounts for 19.2 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 2012, approximately 54 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 223,000 Bpd for 2012 and 226,000 Bpd for 2011.

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 2012, PADD II imported 2.5 million Bpd from outside of the PADD II region. The 2012 data indicates PADD II imported approximately 1.7 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 gap between local supply and demand for crude oil in PADD II to continue to widen, encouraging imports of crude oil from Canada, PADD III and 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 is increasing 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 transportation system servicing the Williston basin in North Dakota and Montana, which includes the Bakken and Three Forks formations. The crude oil gathering pipelines of our North Dakota system collect crude oil from points near, approximately, 4,600 producing wells in North Dakota and Montana. Most deliveries from our North Dakota system are made at Clearbrook to our Lakehead system and to a third-party pipeline system. Our North Dakota system includes approximately 240 miles of crude oil gathering lines connected to a transportation line that is approximately 730 miles long, with a capacity of approximately 210,000 Bpd at the end of 2012. Our North Dakota system also has 21 pump stations, one delivery station and 10 storage facilities with an aggregate working storage capacity of approximately 891,000 barrels.

The following are Bakken Projects that will allow Bakken crude oil to access our markets:

- Bakken Pipeline Expansion—In August 2010, to further solidify our position as the primary transportation provider for crude oil production from the Bakken and Three Forks formations located in the states of Montana and North Dakota and the Canadian provinces of Saskatchewan and Manitoba., we announced the Bakken Pipeline Expansion project, or the Bakken Project, a joint crude oil pipeline expansion project with Enbridge Income Fund Holdings Inc., a partially-owned subsidiary of Enbridge. Upon completion in the first quarter of 2013, the Bakken Project will provide capacity of 145,000 Bpd. This project, with the North Dakota mainline, will result in a total takeaway capacity for this region of 355,000 Bpd. Of the 145,000 Bpd, 100,000 Bpd is in the form of firm commitments with multiple shippers who have committed to the project. For the first year 85,000 Bpd of these commitments we will receive 75% of their shipper-pay payments which are made regardless of shipment of volumes, and 100% thereafter. The term of these contracts are 5 or 10 years with the majority at 10 years.

- Bakken Access Program—In October 2011, we announced the Bakken Access Program, a series of projects which represent an upstream expansion that will further complement our Bakken Project, as discussed above. This access program will substantially enhance our gathering capabilities on the North Dakota system by 100,000 Bpd. This program, expected to be in-service by mid-2013, involves increasing pipeline capacities, construction of additional storage tanks and addition of truck access facilities at multiple locations in western North Dakota.

- Berthold Rail Project—In December 2011, we announced the Berthold Rail Project that will provide an alternative transportation solution to shipper needs in the Bakken region. The project will expand capacity into the Berthold terminal by 80,000 Bpd and includes 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 an additional capacity of 10,000 Bpd to the Berthold Terminal. The loading facility and the crude oil tankage are expected to be placed into service during the first quarter of 2013.

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 the 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 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 has seen increased production levels up to 572,000 Bpd as of December 2012, an approximate 52% increase in production levels since December 2011. 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. Competitors of our North Dakota system include 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 some existing rail loading facilities.

In recent years rail transportation has also emerged as an alternative method of shipping crude to market. While historically rail has not been considered an economically viable transportation solution for producers looking for market access, price spreads driven by limited transportation infrastructure to key markets and the lead time required to get new pipelines into service has opened up opportunities for the railway industry. These transportation and market access constraints have resulted in large crude oil price differences between the North Dakota supply basin and refining market centers. As a result, crude oil producers have begun moving increasing amounts of oil by rail which has increased competition to our North Dakota system and decreased our system utilization. We expect this competition to decrease our 2013 volumes, compared to our volumes for the year ended December 31, 2012. 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. Crude oil producers are expected to then shift their volumes back to pipelines as the primary transportation option since pipeline transportation costs are significantly less costly than rail. We continue to solidify our long term position in the Bakken formation, and the announcement of several expansion projects should increase our available capacity within this region.

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.

Natural Gas Segment

We own and operate natural gas gathering, treating, processing and transportation systems as well as trucking, rail and liquids marketing operations. We purchase and gather natural gas from the wellhead and deliver it to plants for treating and/or processing and to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies.

Natural gas treating potentially involves the removal of hydrogen sulfide, carbon dioxide, water and other substances from raw natural gas so that it will meet the standards for pipeline transportation. Natural gas processing involves the separation of raw natural gas into residue gas and NGLs. Residue gas is the processed natural gas that ultimately is consumed by end users. NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a process known as fractionation and sold as their individual components, including ethane, propane, butanes and natural gasoline. At December 31, 2012, we had eight active treating plants and 25 active processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants. We may idle some of these plants from time to time based on current volumes. Our treating facilities have a combined capacity that approximates 1,090 MMcf/d while the combined capacity of our processing facilities approximates 2,015 MMcf/d, including 350 MMcf/d provided by the HCDP plants.

Our natural gas business consists of the following systems:

- East Texas system: Includes approximately 3,900 miles of natural gas gathering and transportation pipelines, eight natural gas treating plants and five natural gas processing plants, including two HCDP plants.

- Anadarko system: Consists of approximately 2,900 miles of natural gas gathering and transportation pipelines in southwest Oklahoma and the Texas panhandle and 11 natural gas processing plants, which includes the assets we obtained in September 2010 when we acquired the Elk City system.

- North Texas system: Includes approximately 4,600 miles of natural gas gathering pipelines and nine natural gas processing plants located in the Fort Worth basin.

Customers. Our natural gas pipeline systems serve customers predominantly in the United States Gulf Coast region and include both purchasers and producers of natural gas. Purchasers are comprised of large users of natural gas, such as power plants, industrial facilities, local distribution companies, large consumers seeking an alternative to their local distribution company, and shippers of natural gas, such as natural gas producers and marketers, including our Marketing business. Producers served by our systems consist of small, medium and large independent operators and large integrated energy companies. We sell NGLs resulting from our processing activities to a variety of customers ranging from large petrochemical and refining companies to small regional retail propane distributors.

Supply and Demand. Demand for our gathering, treating and processing 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 2012, overall natural gas prices were at levels below the prices experienced in recent years due to excess supplies of natural gas in the United States. While NGL prices were down from prior years, they remained above historical averages most of the year. Ethane and propane prices declined throughout the current year, but the heavier components of NGLs were sustained throughout the 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 natural gas assets are in basins that have the opportunity to grow in an improved pricing environment. All three of our natural gas 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.

Our East Texas system is primarily located in the East Texas basin. The Bossier Trend, which is located on the western side of our East Texas system within the East Texas basin, has been a driver of growth on our East Texas system for the past several years. Production in the Bossier Trend grew from 650 MMcf/d in 1997 to a peak of 2,400 MMcf/d in March of 2009. However, with the decline in natural gas prices, the Bossier Trend has seen a decrease in development with production falling to 1,400 MMcf/d as of August 2012. Low natural gas prices have also lead to decreased drilling activity in and around the Haynesville Shale. The Haynesville Shale is a formation that runs from western Louisiana into eastern Texas, and is one of the largest natural gas discoveries in the United States. Due to lower levels of producer activity, in light of weak natural gas prices, we have deferred portions of our previously announced Haynesville natural gas expansion pending increases in drilling activity. Consistent with trends observed elsewhere, an increase in activity has been noted in the East Texas basin related to horizontal drilling of the Cotton Valley formation which has a high content of NGLs and condensate.

A substantial portion of natural gas on our North Texas system is produced in the Barnett Shale area within the Fort Worth basin conglomerate. The Fort Worth basin conglomerate is a mature zone that is experiencing slow production decline. In contrast, the Barnett Shale area became one of the more active natural gas plays in North America. While abundant natural gas reserves have been known to exist in the Barnett Shale area since the early 1980s, recent technological advances in fracturing the shale formation allows commercial production of these natural gas reserves. Based on the latest information available for 2012, Barnett Shale production has risen from approximately from 110 MMcf/d in 1999 to approximately 5,700 MMcf/d by August 2012. We anticipate that throughput on the North Texas system will be steady in each of the next several years as a result of modest Barnett Shale development due to low natural gas prices. This is a result of producers deploying their resources to other natural gas shale plays with higher liquids content.

Our Anadarko system is located within the Anadarko basin and has experienced considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. Favorable pricing for NGLs relative to the lower prices for natural gas has encouraged producers to increase production in the Granite Wash formation due to the high content of NGLs and condensate present in the natural gas stream. Rig counts have increased steadily since late 2009 with an increased emphasis by producers to use horizontal drilling and multistage hydraulic fracturing technologies. Exploitation of the Granite Wash formation by our customers is primarily due to the successful application of horizontal drilling and fracturing technologies.

In response to the increased supply of natural gas and NGLs and the increased demand for our services in the Anadarko region, we acquired the Elk City system in September 2010. The Elk City system includes one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 MMcf/d, and a combined current NGL production capability of approximately 30,000 Bpd, enabling us to process greater volumes of natural gas resulting from the increased production in the Granite Wash formation. This acquisition enhanced the processing capacity and expansion capability of our Anadarko system. In an effort to further alleviate the capacity constraints resulting from the increasing supplies of natural gas in the areas served by our Anadarko system, we constructed a cryogenic processing plant, which we refer to as the Allison Plant. The Allison Plant was placed into service in November 2011 and is intended to accommodate the increase of horizontal drilling activity that exists in the Granite Wash formation. With the completion of additional third party NGL takeaway capacity to the Allison Plant in April 2012, we can now fully utilize its capacity. In August 2011, we announced plans to construct an additional processing plant and other facilities, including compression and gathering infrastructure, on our Anadarko system, anticipated to be in service in mid-2013 which we refer to as our Ajax Plant. The Allison and Ajax plants, when operational, will increase the total processing capacity on our Anadarko system to approximately 1,200 MMcf/d. Several of our competitors have announced gathering and processing expansions in the Anadarko region which are in various stages of completion. We expect our large geographic footprint, competitively priced services and favorable producer drilling economics will enable us to keep our facilities well utilized for the foreseeable future.

Other potential expansions may arise as more producers begin further developing the Granite Wash, Barnett Shale, Haynesville Shale and other areas in the basins served by our systems and commit for additional capacity. We will opportunistically evaluate strategic prospects to further expand the service capabilities of our existing systems.

Results of our Natural Gas business depend upon the drilling activities of natural gas producers in the areas we serve. We anticipate that volume growth will be modest or flat until forward natural gas prices improve. We expect that natural gas production will continue to rise in areas with high liquids content gas and to decline in our dry gas basins due to low natural gas prices.

In the second half of 2013, a joint venture among us, Enterprise Products, DCP Midstream and Anadarko Petroleum Corporation, or Anadarko, to design and construct a new NGL pipeline and two new NGL gathering systems, collectively referred to as the Texas Express Pipeline project, or TEP will begin service. The pipeline originates at Skellytown, Texas and extends approximately 580 miles to NGL fractionation and storage facilities in Mont Belvieu, Texas and will have an initial capacity of approximately 280,000 Bpd. TEP will assist us in fulfilling our strategic objective of expanding our presence in the natural gas and NGL value chain and provide us with a new source of strong and stable cash flow. For further discussion of TEP see also Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations-Future Prospects for Natural Gas*.

Competition. Competition from other pipeline companies is significant in all the markets we serve. Competitors of our gathering, treating and processing systems include interstate and intrastate pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs. 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 natural gas producers and owners 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 the sour natural gas systems, such as a component of our East Texas system, competition is more limited in certain locations due to the infrastructure required to treat sour natural gas.

Competition for customers in the marketing of residue natural gas is based primarily upon the price of the delivered natural gas, the services offered by the seller and the reliability of the seller in making deliveries. Residue natural gas also competes on a price basis with alternative fuels such as crude oil and coal, especially for customers that have the capability of using these alternative fuels, and on the basis of local environmental considerations. Competition in the marketing of NGLs comes from other NGL marketing companies, producers, traders, chemical companies and other asset owners.

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 pipelines. 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 pipeline systems. 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. These operations include the transportation of NGLs, crude oil and other products by pipeline, truck and railcar from wellheads and treating, processing and fractionation facilities to wholesale customers, such as distributors, refiners and chemical facilities. In addition, our trucking and NGL marketing operations resell these products. A key component of our business is ensuring market access for the liquids extracted at our processing facilities. On average, this accounts for approximately 40% of the volumes marketed or transported by our trucking and NGL marketing business and is a major source of its growth in this area.

Our services are provided using trucks, trailers and rail cars, pipeline capacity, fractionation agreements, product treating and handling equipment. Our trucking operations transport NGLs, condensate and crude oil from our processing facilities and from third party producers to our United States Gulf Coast customers. In October 2010, we acquired the assets of a common carrier trucking company for $10.3 million to meet the growing supply of NGLs, condensate and crude oil, as well as to capitalize on the opportunity to better serve our United States Gulf Coast customers. As a result of the acquisition, our fleet expanded in excess of 250 trucks and in excess of 300 trailers, as of December 31, 2012.

NGL Marketers. Most of the customers of our trucking and NGL marketing operations are wholesale customers, such as refineries and propane distributors. Our trucking and NGL marketing operations also market products to wholesale customers such as petrochemical plants.

Supply and Demand. Supply is sourced from a variety of areas in the United States Gulf Coast, with a significant amount of the NGL volume coming from our own gathering and processing facilities. Crude oil and natural gas prices and production levels affect the supply of these products. The demand for our services is affected by the demand for NGLs and crude oil by large industrial refineries and similar customers in the regions served by this business.

Competition. Our trucking and NGL marketing operations have a number of competitors, including other trucking and railcar operations, pipelines, and, to a lesser extent, marine transportation and alternative fuels. In addition, the marketing activities of our trucking and NGL marketing operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Marketing Segment

Our Marketing segment's primary objectives are to maximize the value of the natural gas purchased by our gathering systems and the throughput on our gathering and intrastate wholesale customer pipelines and to mitigate financial risk. To achieve this objective, our Marketing segment transacts with various counterparties to provide natural gas supply, transportation, balancing, storage and sales services.

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.

REGULATION

Regulation by the FERC of Interstate Common Carrier 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.

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 beginning at page 118 of this annual report on Form 10-K for additional discussion.

Regulation by the FERC 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 intrastate pipeline activities of Enbridge to the jurisdiction of the Texas Railroad Commission via its Informal Complaint Process.

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. In addition, under FERC regulations we are subject to market manipulation and transparency rules. This includes the public posting of certain contract information pursuant to FERC Order No. 735 *et al.*

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-A. Additionally, several of our gathering systems fall under the definition of "major non-interstate pipeline." These systems were previously subject to FERC Order No. 720 *et al.,* however on October 24, 2011 the U.S. Court of Appeals for the Fifth Circuit issued an Opinion vacating the FERC rule (RM08-2) promulgated by Order Nos. 720 and 720-A, which required major intrastate pipelines to post their system's flow information. The Fifth Circuit entered its final mandate on December 30, 2011. In keeping with that mandate, Enbridge ceased posting of capacity and flow information for its major intrastate pipelines on January 3, 2012.

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. Also, some states have, or are considering providing, greater regulatory scrutiny over the commercial regulation of the natural gas gathering business. 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. Certain regulations implemented by the FERC in recent years could increase the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other marketers of these products.

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 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, 2012 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	$ 0.3471	$ 0.3665	$ 0.4008
To Superior, Wisconsin	$ 0.7121	$ 0.7590	$ 0.8410
To Chicago, Illinois area	$ 1.5308	$ 1.6449	$ 1.8451
To Marysville, Michigan area	$ 1.8400	$ 1.9789	$ 2.2225
To Buffalo, New York area	$ 1.8849	$ 2.0275	$ 2.2770
Clearbrook, Minnesota to Chicago	$ 1.3742	$ 1.4688	$ 1.6348

(1) Pursuant to FERC Tariff No. 43.10.0 as filed with the FERC and with an effective date of July 1, 2012 (converted from $/m3 to $/Bbl).

The transportation rates as of December 31, 2012 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 us 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 surcharge, which is added to the base transportation rates, is a cost-of-service based calculation that is trued-up annually (usually in April) for actual costs and throughput from the previous calendar year and is not subject to indexing. The initial term of the SEP II portion of the Settlement Agreement was for 15 years, beginning in 1999 and expiring December 31, 2013.

Terrace Surcharge

Under the 1998 Settlement Agreement, the Lakehead system implemented a transportation rate surcharge for the Terrace expansion program which is referred to as the Terrace Surcharge, of approximately $0.013 per barrel for light crude oil from the Canadian border to Chicago and will remain at this level through 2013, when the Terrace Surcharge ends. In addition to the Terrace Surcharge, included in the tariff agreement are the Terrace Schedule B and C adjustments. The Schedule B adjustment to the Terrace Surcharge is required if the current multi-pipeline cost of equity exceeds the 1998 multi-pipeline rate of return by plus or minus 200 basis points. In 2012, since the current multi-pipeline rate of return plus or minus 200 basis points was less than the 1998 multi-pipeline rate of return, an adjustment to the Terrace Surcharge was made. The Schedule C adjustment to the Terrace Surcharge is required when Terrace Phase III facilities are in service and the annual actual average pumping exiting Clearbrook is less than 225,000 cubic meters, or m^3, per day. In the 2012 Surcharge Filing, the actual annual average pumping for 2011 was slightly below the volume threshold. However, no adjustment was made to the Terrace Surcharge.

Facilities Surcharge

In June 2004, the FERC approved an Offer of Settlement in Docket No. OR04-2-000 between the Lakehead system and CAPP, for a facilities surcharge to be implemented separately from and incrementally to the then-existing surcharges in its tariff rates, which we refer to as the Facilities Surcharge. *Enbridge Energy, Limited Partnership*, 107 FERC ¶ 61,336 (2004). The Facilities Surcharge was intended to be utilized to include additional projects negotiated and agreed upon between the Lakehead system 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 1st 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.

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.

The Line 6B Pipeline Replacement and Dig Program Project, or Project 15 above, consists of two parts:

a. The first is a pipeline replacement which is designed to recover an estimated $288 million in capital cost, including contingency, escalation and Allowance for funds used during construction, or AFUDC. The project includes the replacement of five 5-mile sections of pipe downstream of the pump station between Griffith and Stockbridge and one 50-mile segment of pipe downstream of Stockbridge.

b. The second is a 2012 dig program which permits Enbridge to recover the average capital cost per dig undertaken in 2012 for digs in excess of 100 digs per year. These costs are to be included in the Facilities Surcharge for 2012. A dig program involves rehabilitation of sections of pipeline to extend its useful life, and lessen the potential for a pipeline release.

The Griffith Terminal Expansion Project, or Project 16 above, is designed to recover an estimated $21.8 million in capital cost, including contingency and market escalation.

Enbridge Energy and CAPP have agreed that the costs associated with Line 6B Replacement and Dig Program Project and Griffith Terminal Expansion Project should be recovered through the FSM. Since the filing was uncontested, the Commission accepted the Supplement to the Settlement on the grounds that it is fair, reasonable, and in the public interest.

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.

The Flanagan Tank Replacement Project, or Project 17 above, has an overall estimated capital cost of $38.7 million and includes the replacement of two out of service tanks with two new tanks.

The Eastern Access Phase 1 Mainline Expansion, or Project 18 above, has an overall estimated capital cost of $1.5 billion which is a decrease from the filing of $1.7 billion, including contingency, market escalation, and AFUDC. It has three main components:

a. The Line 5 Mainline Expansion will provide an additional 50,000 Bpd of light crude oil capacity on Line 5 from Superior, Wisconsin to Sarnia, Ontario, at an estimated capital cost of $101.8 million, which is an increase from the filing of $95.3 million. The quoted annual capacity of Line 5 is 490,000 Bpd;

b. The Line 62 Spearhead North Expansion involves adding two new pump stations and one new 333,000-barrel tank in Flanagan, Illinois, which will provide an additional 105,000 Bpd of capacity on Line 62 between Flanagan, Illinois and Hartsdale, Indiana, at an estimated capital cost of $315 million, which is an increase from the filing of $280 million; and

c. The Line 6B Replacement involves installation of 160 miles of 36-inch pipeline from Griffith, Indiana to Stockbridge, Michigan. This upsized pipeline will provide an additional 260,000 Bpd of capacity on that line segment at an estimated capital cost of $1.1 billion, which is a decrease from the filing of $1.3 billion.

As of December 31, 2012, the Facilities Surcharge was $0.5712 per barrel for light crude oil movements from the International border near Neche, North Dakota to Chicago, Illinois.

Other Tariff and Transportation Rate Cases

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. The damage claim portion of the PBF complaint is redacted, so an estimate of damages cannot be provided. 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. PBF filed an answer to Enbridge on June 26, 2012, and Enbridge filed a further reply on July 3, 2012, re-stating that this is a long held practice and to order it to be changed would have negative consequences on other shippers. On August 9, 2012, FERC set the matter for hearing, first ordering a settlement process. The first settlement meeting was September 25, 2012. The second settlement meeting was held on November 7, 2012, at which time Enbridge and PBF expressed that they were unable to settle the matter. On November 16, 2012, the settlement judge issued an order terminating the settlement process and appointing an Administrative Law Judge for the hearing. The case is on a Track III schedule, meaning the hearing will commence within 42 weeks (i.e., by September 6, 2013), and the initial decision must be issued within 63 weeks (i.e., by January 2014).

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. High Prairie filed its answer on June 20, 2012, alleging that Enbridge misstated the facts and the law. Enbridge filed its response on July 5, 2012, reiterating that the law is clear and that High Prairie is trying to obfuscate that fact by focusing on its version of the facts. High Prairie filed a further response on July 13, 2012. A FERC decision has not yet been issued.

On October 22, 2012, Enbridge filed FERC Tariff No. 41.3.0 canceling FERC Tariff No. 41.2.0. The proposed tariff revises Enbridge's downstream nomination verification procedure in Enbridge's Rules and Regulations tariff by eliminating a frozen 24-month historical period and substituting it with the capability of the 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 establishing a technical conference. The first technical conference session will likely be held at FERC on February 6, 2013.

International Joint Tariff

FERC Tariff No. 45.1.0, issued May 31, 2012, revised the International Joint Tariff, or IJT, effective July 1, 2012, by increasing the transportation tolls by 2.447% and including a credit for the Line 5 Claim of $0.263 per cubic meter for movements of heavy crude from Hardisty, Alberta to the U.S. border near Gretna, Manitoba. 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 comprised of pipeline, terminaling and storage infrastructure located in the Mid-Continent region of the United States. Specifically, the system originates in Cushing and offers transportation service to Wood River, and other Mid-Continent system facilities, local area refineries and to other interconnected non-affiliated pipelines. The transportation rate for light crude oil from Cushing to principal delivery points are set forth below:

	Published Transportation Rate Per Barrel
To Wood River	$ 0.5948[1]
Transfer charge at Cushing	$ 0.1305[2]

(1) Pursuant to FERC Tariff No. 48.2.0 as filed with the FERC on May 31, 2012, with an effective date of July 1, 2012.

(2) Pursuant to FERC Tariff No. 51.2.0 as filed with the FERC on May 31, 2012, with an effective date of July 1, 2012.

The transportation rates as of December 31, 2012, 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 January 4, 2012, the North Dakota system filed an amendment to its Rules and Regulations in order to enhance and clarify the quality specifications contained within the tariff to be effective February 4, 2012. The tariff established new volumetric penalties for Sulfur, API Gravity, and Basic Sediment and Water. In response to a protest that was filed, the Commission rejected the tariff on the basis that Enbridge North Dakota had not provided evidence to support the need for and the levels of the proposed penalties.

On February 29, 2012, notice was provided by the North Dakota system of the extension of the temporary, partial embargo for deliveries to Clearbrook, Minnesota from the Berthold, North Dakota receipt point due to vibration issues that had occurred at Berthold. Initial notice of the temporary, partial embargo was provided on October 28, 2011.

On March 1, 2012, the North Dakota system filed to provide notice of the lifting of the temporary, partial embargo, to establish an initial rate for a gathering service at Alexander and to incorporate an updated calculation of the surcharges on the two previously approved Phase 5 and 6 expansions. The tariff went into effect April 1, 2012.

On May 31, 2012, the North Dakota system amended its Rules and Regulations tariff by implementing a revised mid-month call for crude process. The tariff went into effect July 1, 2012.

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 August 31, 2012, the North Dakota system filed to establish initial gathering and truck unloading services and charges at Alexander, North Dakota and Tioga, North Dakota. The two $0.10/Bbl interconnection rates resulted from shippers' requests for pipeline interconnections with two shippers to facilitate receipts into Enbridge North Dakota at Alexander and Tioga. The tariff became effective October 1, 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 will result 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. At the time of this filing our Petition for Declaratory Order process is ongoing.

In the first quarter of 2013, the Bakken Project will go into service and will transport 145,000 Bpd of Bakken crude from the North Dakota system to Cromer, Manitoba, Canada.

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, Newberg, and Sherwood, North Dakota to Clearbrook, Minnesota	$1.2265
From Berthold, North Dakota to Clearbrook, Minnesota or the International boundary near Portal, North Dakota	$1.2265
From Stanley, North Dakota to Clearbrook or the International boundary near Portal, North Dakota	$1.2265
From Grenora, North Dakota to Clearbrook, Minnesota or the International boundary near Portal, North Dakota	$1.3718
From Flat Lake and Reserve, Montana to Clearbrook, Minnesota or the International boundary near Portal, North Dakota	$1.4039
From Tioga, North Dakota to Clearbrook, Minnesota or the International boundary near Portal, North Dakota	$1.2584
From Trenton, North Dakota to Clearbrook, Minnesota or the International boundary near Portal, North Dakota	$1.8893
From Alexander, North Dakota to Clearbrook, Minnesota or the International boundary near Portal, North Dakota	$1.9374
From Reserve, Montana to Tioga, North Dakota	$0.7104
From Trenton, North Dakota to Tioga, North Dakota	$0.9533
From Alexander, North Dakota to Tioga, North Dakota	$1.0013
From (pump-over) Stanley, North Dakota to Stanley, North Dakota	$0.2500
From Tioga, North Dakota to Stanley, North Dakota	$0.9411
From Grenora, North Dakota to Stanley, North Dakota	$1.0455
From Reserve, Montana to Stanley, North Dakota	$1.0751
From Trenton, North Dakota to Stanley, North Dakota	$1.5502
From Alexander, North Dakota to Stanley, North Dakota	$1.5945
Gathering from Newburg, North Dakota or Flat Lake, Montana	$0.8233

(1) Pursuant to FERC Tariff No. 72.20.0 as filed with the FERC on August 31, 2012, with an effective date of October 1, 2012.

(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.

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. For example, the Marshall release resulted in a record $3.7 million civil penalty and multiple recommendations from the resultant NTSB investigation. 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 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 SO2, emissions from the Oil and Natural Gas Sector. The final standards were published and became effective on August 16, 2012. The compliance dates range from October 15, 2012, to October 15, 2013, dependent on the affected equipment. 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-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. 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, 2013. 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 another Enbridge subsidiary.

The coverage limits and deductible amounts at December 31, 2012 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 $660.0	$ 0.1
Pollution liability	Up to $660.0	$ 5.0

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.

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.

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, referred to as 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, 2012, we have provided $231.8 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, 2012, we would have been required to provide additional letters of credit in the aggregate amount of $45.4 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, 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;
- 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 and 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;
- 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 being heard have been towards 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 factor.

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, Minnesota, Chicago, Detroit, Michigan, Toledo, Buffalo, New York, 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.

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 and NGLs in connection with our marketing activities. Our exposure to commodity price volatility is inherent to our natural gas and NGL purchase and resale activities, in addition to our natural gas processing activities. 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 fees we derive from 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 financial performance.

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, 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.

In June of 2009, the United States House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which was then placed on the United States Senate legislative calendar for consideration. However, the Senate never acted on the legislation during the 111th Congress, which ended at the end of 2010. The U.S Environmental Protection Agency (EPA) is working on regulations to limit greenhouse gas emissions within its existing statutory authority under the Clean Air Act. In addition, more than one-third of the states already have begun implementing legal measures to reduce emissions of greenhouse gases. Further, on April 2, 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an “air pollutant” under the federal CAA. In July 2008, the EPA released an Advanced Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the CAA and other potential methods of regulating greenhouse gases. On December 7, 2009, the EPA finalized its response to the Massachusetts, et al. v. EPA decision by issuing its “endangerment finding” that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change. Moreover, on September 22, 2009, the EPA finalized 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 finalized 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. Finally, the May 2010 promulgation of regulations to control the greenhouse gas emissions from light-duty motor vehicles (the “tailpipe rule”) automatically triggered CAA provisions that, in general, require stationary source facilities that emit more than 25,000 tons per year of greenhouse gas 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 finalized the “tailoring rule,” which served to increase the greenhouse gas emissions threshold that triggers the permitting requirements for stationary sources. Under a phased-in approach, for most purposes, new permitting provisions are required for facilities that emit 100,000 tons per year or more of carbon dioxide equivalent. On June 26, 2012, the Circuit Court of Appeals for the District of Columbia circuit upheld the endangerment finding, as well as the tailpipe rule, and ruled that no petitioners had standing to challenge the timing and tailoring rules. Although it is not possible at this time to predict whether proposed legislation or regulations will be enforced as initially written, if at all, or how legislation or new regulation that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions.

The United States Congress has been considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs as discussed above. Any additional costs or operating restrictions associated with 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 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.

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.

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 security 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 security 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.

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.

These exceptions also expressly permitted the reversal by Enbridge in 1999 of one of its pipelines that extends from Sarnia to Montreal, Quebec. As a result of this reversal, Enbridge competes with us to supply crude oil to the Ontario market.

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.

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.

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, 2013. 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 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.

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 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.

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.

PART II

Item 5. Market for Registrant's Common Equity and Related Unitholder Matters

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 2012 and 2011 are summarized as follows:

	First	Second	Third	Fourth
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
2011 Quarters				
High	$ 33.86	$ 34.58	$ 30.24	$ 33.22
Low	$ 30.25	$ 28.50	$ 25.03	$ 24.66
Cash distributions paid	$ 0.51375	$ 0.51375	$ 0.53250	$ 0.53250

On February 13, 2013, the last reported sales price of our Class A common units on the NYSE was $29.47. At January 31, 2013, there were approximately 90,000 Class A common unitholders, of which there were approximately 1,200 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.

Other Matters. In January 2011, we issued 50,650 Class A common units in connection with a land acquisition, and in May 2012 we issued 64,464 Class A units in connection with another land acquisition. Both unit issuances were exempted from registration pursuant to Section 4(c) of the Securities Act of 1933, as amended.

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 beginning at page 118. See also Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

	December 31, 2012	2011	2010	2009	2008
	(in millions, except per unit amounts)				
Income Statement Data:(2)(5)(6)(7)(8)(9)(10)(11)					
Operating revenues	$ 6,706.1	$ 9,109.8	$ 7,736.1	$ 5,731.8	$ 9,898.7
Operating expenses	5,812.9	8,113.0	7,608.8	5,115.2	9,318.1
Operating income	893.2	996.8	127.3	616.6	580.6
Interest expense	345.0	320.6	274.8	228.6	180.6
Other income	10.0	6.5	17.5	13.4	1.9
Income tax expense	8.1	5.5	7.9	8.5	7.0
Noncontrolling interest	57.0	53.2	60.6	11.4	—
Income (loss) from continuing operations attributable to general and limited partnership interests	$ 493.1	$ 624.0	$ (198.5)	$ 381.5	$ 394.9
Income (loss) from continuing operations per limited partner unit (basic and diluted)(1)	$ 1.27	$ 1.99	$ (1.09)	$ 1.12	$ 1.78
Cash distributions paid per limited partner unit	$ 2.1520	$ 2.0925	$ 2.0240	$ 1.9800	$ 1.9400
Financial Position Data (at year end):(2)(3)(4)(5)(6)(7)(8)(9)					
Property, plant and equipment, net	$ 10,937.6	$ 9,439.4	$ 8,641.6	$ 7,716.7	$ 6,722.9
Total assets	12,796.8	11,370.1	10,441.0	8,988.3	8,300.9
Long-term debt, excluding current maturities	5,501.7	4,816.1	4,778.9	3,791.2	3,223.4
Notes payable to General Partner	330.0	342.0	347.4	269.7	130.0
Partners' capital:					
Class A common units	3,590.2	3,386.7	2,641.0	2,884.9	2,104.0
Class B common units	83.9	82.2	64.9	78.6	85.0
Class C units(12)	—	—	—	—	886.5
i-units	801.8	728.6	579.1	588.8	553.8
General Partner	299.0	285.6	256.8	251.1	84.7
Accumulated other comprehensive income (loss)	(320.5)	(316.5)	(121.7)	(74.6)	12.9
Noncontrolling interest	793.5	445.5	465.4	341.1	—
Partners' capital	$ 5,247.9	$ 4,612.1	$ 3,885.5	$ 4,069.9	$ 3,726.9
Cash Flow Data:(2)(3)(4)(5)(6)(7)(8)					
Cash flows provided by operating activities	$ 851.0	$ 1,045.6	$ 377.9	$ 728.4	$ 543.3
Cash flows used in investing activities	1,906.6	1,099.0	1,427.8	1,173.6	1,428.3
Cash flows provided by financing activities	860.6	331.4	1,051.2	248.9	1,174.4
Additions to property, plant and equipment and acquisitions included in investing activities, net of cash acquired	1,826.2	1,143.2	1,429.5	1,292.1	1,387.1

(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: 2012, $129.3 million; 2011, $104.5 million; 2010, $61.6 million; 2009, $57.1 million; and 2008, $49.5 million.

(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
December 2008	9.875% Senior Notes	$500
April 2008	6.500% Senior Notes	$400
April 2008	7.500% Senior Notes	$400

- 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.
- For the year ended December 31, 2008 we made the following debt repayments:
  – $31.0 million of our First Mortgage Notes; and
  – $25.0 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
December 2008	Class A	32,500,000	$ 509.8
March 2008	Class A	9,200,000	$ 221.8

- 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
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
2008	$ 54.2	$ 72.2	$ 2.6	$ 286.7

- The quarterly in-kind distributions of 2.6 million, 2.4 million, 2.5 million, 3.3 million and 2.4 million i-units during 2012, 2011, 2010, 2009 and 2008, respectively, in lieu of cash distributions; and

- The quarterly in-kind distributions of 1.6 million Class C units during both 2009 and 2008, 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, 2012, 2011 and 2010, 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, 2012, 2011 and 2010 we will incur aggregate gross costs of $55.0 million, $218.0 million and $595.0 million, respectfully, 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, 2012, and 2011 we recognized $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, 2012, Enbridge and its affiliates, including us, have exceeded the limits of coverage under this insurance policy, but expect to recover the remaining $145.0 million balance of our aggregate insurance coverage.

(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, will cost approximately $2.6 billion and will be undertaken on a cost-of-service basis and will be funded 60% by our General Partner and 40% by the Partnership under the Eastern Access Joint Funding Agreement. In conjunction with our application of the provisions of regulatory accounting, we recorded AEDC of $4.7 million for the year ended December 31, 2012, 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.

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

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes 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.

The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31, 2012, 2011 and 2010.

	December 31,		
	2012	2011	2010
		(in millions)	
Operating Income (loss)			
Liquids	$ 706.8	$ 816.2	$ (24.7)
Natural Gas	200.1	183.6	152.4
Marketing	(11.4)	(0.8)	3.7
Corporate, operating and administrative	(2.3)	(2.2)	(4.1)
Total Operating Income	893.2	996.8	127.3
Interest expense	345.0	320.6	274.8
Other income	10.0	6.5	17.5
Income tax expense	8.1	5.5	7.9
Net income (loss)	550.1	677.2	(137.9)
Less: Net income attributable to noncontrolling interest	57.0	53.2	60.6
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 493.1	$ 624.0	$ (198.5)

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, 2012 decreased $109.4 million, as compared with the same period in 2011, primarily due to the following:

- Increased average daily volumes resulting in $25.1 million additional operating revenue;
- Increased operating revenue of $17.0 million due to higher indexed tariff rates for our Lakehead, North Dakota and Ozark systems;
- Increased operating revenue of $14.9 million for fees collected from our Cushing storage terminal facility;
- Increased operating revenue of $11.8 million due to higher recovery of capital costs in our annual tolls related to the Line 6B Pipeline Integrity Plan;
- Increased environmental costs, net of insurance recoveries, of $21.6 million for the year ended December 31, 2012 when compared to the same period of 2011;
- Decreased unrealized, non-cash, mark-to-market net gains of $13.1 million for the year ended December 31, 2012, on derivative financial instruments that do not qualify for hedge accounting treatment;
- Increased "Operating and administrative" expenses of $79.4 million primarily due to:
    - — Increased workforce related costs and other allocated expenses of $28.2 million;
    - — Increased supporting 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
    - — Increased pipeline integrity costs of $11.2 million.
- Increased Oil measurement adjustments due to a $52.2 million settlement with a shipper on our Lakehead crude oil pipeline system in 2011 that did not occur in 2012;
- Increased power costs of $4.0 million primarily associated with the higher volumes of crude oil transported on our Lakehead system; and
- Increased depreciation expense of $12.9 million for the year ended December 31, 2012, directly attributable to additional assets placed into service since 2011.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines as well as natural gas treating and processing plants and related facilities. The revenues of our Natural Gas segment are associated with services we provide to gather and process natural gas and to transport natural gas on our pipelines. Generally, our revenues are in the form of fee for service arrangements and sales of natural gas and NGLs.

The operating income of our Natural Gas business for the year ended December 31, 2012 increased $16.5 million, as compared with the same period in 2011, primarily due to the following:

- Decreased gross margin due to the significant decline in natural gas and NGL prices for the year ended December 31, 2012 when compared to the same period in 2011;
- Increased operating revenue less the cost of natural gas derived from keep-whole processing earnings of $49.2 million;
- Increased operating income of approximately $33.0 million due to "accounting misstatements" and "accounting errors" for NGL product purchases and sales made by our trucking and NGL marketing subsidiary for the year ended December 31, 2010 that were recorded for the year ended December 31, 2011 with no such misstatements or errors recorded for the year ended December 31, 2012;
- Increased operating income of approximately $13.0 million due to unusually adverse weather conditions and plant downtime for the year ended December 31, 2011 that negatively impacted gross margin relative to typical weather related upsets experienced in 2012;
- Increased fee-based operating income of approximately $13.0 million on our East Texas, Anadarko, and Oklahoma systems due to higher fees resulting from lower field operating pressures, contract changes, and additional Haynesville volumes;
- Increased operating income of approximately $11.2 million from improved Anadarko NGL processing efficiencies and higher NGL content in the natural gas processing stream;
- Increased operating income of approximately $10.8 million from our condensate marketing business due to higher realized margins from facilities placed into service during 2012;
- Decreased operating income of $11.5 million in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment, as compared with the same period of 2011;
- Increased operating and administration costs of $67.2 million for the year ended December 31, 2012, as compared with the same period in 2011 primarily due to:
  - — 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 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 2011;
  - — Increased current year costs of $7.5 million for investigation costs related to accounting misstatements at our trucking and NGL marketing subsidiary;
  - — Increased 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;
  - — Increased current year costs of $4.3 million for the write down of surplus materials associated with the deferred portions of the Haynesville expansion within our East Texas system; and
- Decreased depreciation expense of $7.8 million, for the year ended December 31, 2012, primarily due to a revision in depreciation rates for the Anadarko, North Texas and East Texas systems in 2011.

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 income of our Marketing business for the year ended December 31, 2012 decreased $10.6 million, as compared with the same period of 2011. Primarily contributing to the operating loss of our Marketing business were lower and relatively stable natural gas prices during the year ended December 31, 2012, when compared to the same period of 2011, which limited opportunities to benefit from price differentials between market centers.

Additionally, the operating results of our Marketing business for the year ended December 31, 2012 included unrealized, non-cash, mark-to-market, net losses of $3.1 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with $0.7 million of unrealized, non-cash, mark-to-market, net gains for the year ended December 31, 2011.

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

	December 31,		
	2012	2011	2010
		(in millions)	
Liquids segment			
Non-qualified hedges	$ 1.3	$ 14.4	$ (2.8)
Natural Gas segment			
Hedge ineffectiveness	3.1	(5.3)	3.5
Non-qualified hedges	1.2	21.1	0.9
Marketing			
Non-qualified hedges	(3.1)	0.7	(6.7)
Commodity derivative fair value net gains (losses)	2.5	30.9	(5.1)
Corporate			
Hedge ineffectiveness	(20.5)	(0.3)	—
Non-qualified interest rate hedges	(0.5)	(0.5)	(1.0)
Derivative fair value net gains (losses)	$ (18.5)	$ 30.1	$ (6.1)

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,		
	2012	2011	2010
		(in millions)	
Operating Results			
Operating revenues	$1,345.8	$1,285.4	$1,171.8
Environmental costs, net of recoveries	(91.3)	(112.9)	600.8
Oil measurement adjustments	(11.5)	(63.4)	5.6
Operating and administrative	383.0	303.6	259.9
Power	148.8	144.8	141.1
Depreciation and amortization	210.0	197.1	178.8
Impairment charge	—	—	10.3
Operating expenses	639.0	469.2	1,196.5
Operating income (loss)	$ 706.8	$ 816.2	$ (24.7)
Operating Statistics			
Lakehead system:			
United States[1]	1,405	1,327	1,302
Province of Ontario[1]	385	373	353
Total Lakehead system delivery volumes[1]	1,790	1,700	1,655
Barrel miles (billions)	480	450	439
Average haul (miles)	732	725	727
Mid-Continent system delivery volumes[1][2]	223	226	212
North Dakota system:			
Trunkline	203	193	159
Gathering	3	4	6
Total North Dakota system delivery volumes[1]	206	197	165
Total Liquids segment delivery volumes[1]	2,219	2,123	2,032

(1) Average barrels per day in thousands.

(2) Includes average system deliveries of 7,000 Bpd for the year ended 2010, from the West Tulsa crude oil pipeline which was removed from service in September 2010.

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. Additional environmental costs and insurance recoveries are discussed below under *Operating Impact of Lines 6A and 6B Crude Oil Release*s. 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, 2012, 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.

The increase in depreciation expense of $12.9 million for the year ended December 31, 2012 is directly attributable to the additional assets we have placed in service since the same period in 2011.

Operating Impact of Lines 6A and 6B Crude Oil Releases

We continue to perform necessary remediation, restoration and monitoring of the areas affected by the crude oil release from Line 6B of our Lakehead system. With respect to the Line 6B incident, we expect to make payments for additional costs associated with submerged oil and recovery operations, including remediation and restoration of the area, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All the initiatives we are undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. Primarily due to an estimate of extended oversight by regulators and additional legal costs associated with various lawsuits, we have revised our total cost estimate to $820 million for the Line 6B incident, before insurance recoveries, for the year ended December 31, 2012, reflecting an increase of $55 million from our estimate at December 31, 2011. Our total cost estimate for the Line 6A crude oil release remains unchanged at approximately $48 million, before insurance recoveries and excluding additional fines and penalties. We continue to monitor this estimate to determine if our estimate should be updated. We have the potential of incurring additional costs in connection with these incidents including modified remediation requirements, other fines and penalties, as well as expenditures for litigation and settlement of claims. Our estimated costs for these incidents are based on currently available information and will be updated as considered necessary to incorporate material new information as it becomes available.

On July 2, 2012, we received a Notice of Probable Violation, or NOPV, from the PHMSA, related to the Line 6B crude oil release, which indicated a $3.7 million civil penalty that we paid during the third quarter of 2012. We have included the amount of the penalty in our total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012, the NTSB discussed the results of its investigation into the Line 6B crude oil release and subsequently publicly posted its final report on July 26, 2012. We provided a reply to the NTSB on October 22, 2012 stating that we have either already or will soon be, fully implementing all of the NTSB recommendations.

On October 3, 2012, we received a letter from the EPA regarding a proposed order, which we refer to as the Proposed Order, for potential incremental containment and active recovery of submerged oil. We are in discussions with the EPA regarding the agency's intent with respect to certain elements of the Proposed Order and the appropriate scope of these activities. The nature and scope of any additional remediation activities that regulators may require is currently uncertain. Studies and additional technical evaluation by the EPA, the Partnership and other regulatory agencies may need to be completed before a final determination of any additional remediation activities can be determined. We have accrued the estimated costs we deem likely to be incurred. However, when a final determination of the appropriate nature and scope of any additional remediation is made, it could result in significant cost being accrued.

The claims for the crude oil release for Lines 6B were covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650.0 million for pollution liability. We have exceeded the limits of coverage under this insurance policy. 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.

Enbridge's current comprehensive insurance program, which became effective May 1, 2012 has a current liability aggregate limit of $660.0 million, including pollution liability, and will remain effective through April 30, 2013.

Year ended December 31, 2011 compared with year ended December 31, 2010

The operating revenue of our Liquids business increased for the year ended December 31, 2011 when compared with the same period in 2010 partially due to higher average daily delivery volumes on all three of our systems, when compared to the same period in 2010. The overall increase in average delivery volumes on our systems increased operating revenues by approximately $40.7 million for our Liquids segment. The total average daily deliveries from our liquid systems increased over four %, to 2.123 million barrels per day, or Bpd, for the year ended December 31, 2011 from 2.032 million Bpd for the same period in 2010. The increase in average deliveries on our liquid systems was partly attributable to the operation of Lines 6A and 6B, which were shut down for part of 2010 due to the Line 6A and Line 6B crude oil releases.

Average daily delivery volumes on our North Dakota system increased 19% during the year ended December 31, 2011 to 197,000 Bpd from 165,000 Bpd during the same period in 2010. The additional volumes were the result of an increase in capacity on our North Dakota system resulting from the elimination of segregated sour service on the system.

Further contributing to the increase in operating revenue was the completion of our Alberta Clipper Pipeline in April 2010. The Alberta Clipper Pipeline contributed approximately $34.8 million of additional operating revenue for the year ended December 31, 2011, when compared with the same period in 2010.

Another contributing factor to the increase in operating revenue is a $17.2 million increase in unrealized, non-cash, mark-to-market net gains related to derivative financial instruments as compared with the same period in 2010. In March 2010, we began to 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 executed 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.

Our transportation tariffs allow our pipelines to deduct an allowance from our customers for the transportation of their crude oil. We recognize revenue for this allowance at the prevailing market price for crude oil. The average prices of crude oil during the year ended December 31, 2011 were higher than the average prices for the same period of 2010. For example, the average allowance oil prices for North Dakota increased approximately 30% for the year ended December 31, 2011, as compared with the same period in 2010. Coupled with the increased liquids volumes, we have experienced an approximate $15.5 million increase in allowance oil revenues.

The operating results of our Liquids business were significantly affected by the crude oil releases from Lines 6A and 6B of our Lakehead system. At December 31, 2011, we revised our total estimate for this crude oil release to $765.0 million, an increase of $215.0 million from December 31, 2010. At December 31, 2011, we had made payments totaling $570.2 million for costs associated with the Line 6B crude oil release, $276.6 million of which relates to the year ended December 31, 2011. The decrease of $713.7 million in environmental expenses, net of recoveries for the year period ended December 31, 2011 when compared to the same period in 2010, is primarily due to recognizing $595.0 million of costs for the Line 6A and Line 6B incidents for the year of 2010 compared to $218.0 million of cost for these incidents offset by insurance recoveries of $335.0 million for the year ended December 31, 2011.

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 June 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.

The "Operating and administrative" expenses of our Liquids business increased $43.7 million from the year ended December 31, 2011, when compared with the same period in 2010 primarily due to the following:

- Higher costs related to our pipeline integrity program;
- Additional workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our systems;
- Property tax increases associated with assets we constructed and placed in service;
- Higher costs for repair and maintenance activities; and
- Increases in other variable costs incurred in relation to our expanded pipeline systems.

Power costs increased $3.7 million for the year ended December 31, 2011, compared with the same period in 2010. The increase in power costs is primarily associated with the higher volumes of crude oil transported on all three of our liquids systems coupled with utility rate increases for power used by our Lakehead system.

The increase in depreciation expense of $18.3 million is directly attributable to the additional assets we have placed in service since the same period in 2010.

In September 2010, our West Tulsa crude oil pipeline was abandoned due to a significant decrease in throughput on the pipeline and, as a result, we recognized a $10.3 million impairment charge during the third quarter of 2010 to reduce the carrying amount of the asset to zero, as compared to no such impairments in the same period in 2011.

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. Historically, western Canada has been a key source of oil supply serving the United States' energy needs. Canada's oil sands, one of the largest oil reserves in the world, are an increasingly prominent source of supply. Over the last several years, as conventional crude oil production has declined, development of the Alberta Oil Sands has more than offset this reduction. The NEB estimates that total WCSB production averaged approximately 3.1 million Bpd in 2012 and 2.8 million Bpd in 2011. Volumes of WCSB crude oil production are comparable with production volumes from Iraq and Venezuela, key members of OPEC. The CAPP in June 2012 estimated future production from the Alberta Oil Sands to continue to grow steadily during the next 18 years, with an additional 3.4 million Bpd of incremental supply available by 2030, based on a subset of currently approved applications and announced expansions. We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets in the United States.

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 average approximately 2 million Bpd in 2013, which is 200,000 Bpd higher than the 1.8 million Bpd of actual deliveries in 2012. The ability to increase deliveries and to expand the Lakehead system in the future will ultimately depend upon a number of factors including crude oil prices, related development activities by crude oil producers in the region and competing pipelines.

North Dakota and Montana in the United States and the province of Saskatchewan in Canada have experienced tremendous growth in the development of crude oil and natural gas reserves from the Bakken formation. The latest data released in August 2012 by the EIA shows that proved reserves of crude oil in North Dakota have increased to 1.8 billion barrels at December 31, 2010, a 73% increase from December 31, 2009. Further, the Three Forks formations, located underneath the Bakken, is thought to be the next natural step in the development of this region.

In recent years rail transportation has emerged as an alternative method of shipping crude to market. While historically rail has not been considered an economically viable transportation solution for producers looking for market access, price spreads driven by limited transportation infrastructure to key markets and the lead time required to get new pipelines into service has opened up opportunities for the railway industry. These transportation and market access constraints have resulted in large crude oil price differences between the North Dakota supply basin and refining market centers. As a result, crude oil producers have begun moving increasing amounts of oil by rail which has increased competition to our North Dakota system and decreased our system utilization. We expect this competition to decrease our 2013 volumes, compared to our volumes for the year ended December 31, 2012. Future pipeline expansions and enhanced market access to eastern Canadian markets and eastern PADD II are expected to decrease current crude oil price differentials. Crude oil producers are expected to then shift their volumes back to pipelines as the primary transportation option since pipeline transportation costs are significantly less costly than rail. We continue to solidify our long term position in the Bakken formation, and the announcement of several expansion projects should increase our available capacity within this region.

The table below summarizes the Partnership's commercially secured projects for the Liquids segment, which will be placed into service in future periods.

Projects	Total Estimated Capital Costs	Expected In-Service Date	Funding
	(in millions)		
Eastern Access Projects			
Line 5, Line 62 Expansion, Line 6B Replacement	$ 2,050	2013—2014	Joint[(1)]
Eastern Access Upsize—Line 6B Expansion	364	Early 2016	Joint[(1)]
U.S. Mainline Expansions			
Line 67 & Line 61 (phase 1)	420	Q3 2014	Joint[(2)]
Chicago Area Connectivity (Line 62 twin)	495	Mid 2015	Joint[(2)]
Line 61 (phase 2)	1,250	Mid 2015, 2016	Joint[(2)]
Line 67 (phase 3)	240	2015	Joint[(2)]
Berthold Rail	145	Q1 2013	EEP
Bakken Pipeline Expansion	300	Q1 2013	EEP
Bakken Access Program	100	Mid 2013	EEP
Sandpiper Project	2,500	Early 2016	EEP
Line 6B 75-mile Replacement Program	317	Q4 2013	EEP

(1) Jointly funded 40% by the Partnership and 60% by our General Partner under Eastern Access Joint Funding agreement. Estimated capital costs presented are before our General Partner's contributions.

(2) Jointly funded 40% by the Partnership and 60% by our General Partner under Mainline Expansion Joint Funding agreement. Estimated capital costs presented are before our General Partner's contributions.

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 expansion will involve construction of an approximately 600-mile 24-inch diameter line from Beaver Lodge, North Dakota, to the Superior, Wisconsin, mainline system terminal. The new line will twin the 210,000 Bpd North Dakota system mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 225,000 Bpd of capacity on the twin line between Beaver Lodge and Clearbrook and 375,000 Bpd between Clearbrook and Superior. The Sandpiper Project is estimated to cost approximately $2.5 billion and will be fully funded by the Partnership. The capital cost will be rolled into the existing North Dakota System rate base, with the associated cost-of-service to be recovered in tolls. The pipeline is expected to begin service in early 2016, subject to regulatory approvals.

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 in Canada in the provinces of Ontario and Quebec for light crude oil produced in western Canada and the United States. One of the projects involves the expansion of the Partnership's Line 5 light crude line between Superior, Wisconsin and Sarnia, Ontario by 50,000 Bpd. Complementing the Line 5 expansion, Enbridge announced plans to reverse portions of its Line 9A and Line 9B in western Ontario to permit crude oil movements eastbound from Sarnia to Westover, Ontario and as far as Montreal, Quebec. The Line 5 expansion is targeted to be in service during the first quarter of 2013, and the Line 9A and Line 9B reversal is targeted to be in service in late 2013 and in 2014, respectively. 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 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.

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, between Flanagan, Illinois and the Terminal at Griffith, Indiana by adding horsepower to increase capacity from 130,000 Bpd to 235,000 Bpd, and an additional 330,000 barrel crude oil tank at Griffith; and 2) replacement of additional sections of the Partnership's Line 6B in Indiana and Michigan to increase capacity from 240,000 Bpd to 500,000 Bpd. Portions of the existing 30-inch diameter pipeline will be replaced with 36-inch diameter pipe. Subject to customary regulatory approvals, these projects are expected to be placed in-service during 2013 and 2014. These projects, including the previously announced Line 5 expansion, 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 is until July 2021.

As part of The Light Oil Market Access Program announced in December 2012, the Partnership will upsize the Eastern Access projects, which includes further expansion of the Line 6B component with increasing capacity from 500,000 Bpd to 570,000 Bpd, at an expected cost of approximately $364 million. This further expansion of the Line 6B component is expected to begin service in early-2016.

These projects collectively referred to as the Eastern Access Projects, will cost approximately $2.5 billion and will be undertaken on a cost-of-service basis and will be funded 60% by our General Partner and 40% by the Partnership under a Eastern Access Joint Funding Agreement. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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.

U.S. Mainline Expansion

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 finalization of scope and regulatory and shipper 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 third quarter of 2014.

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 $1,250 million. Some of the overall expansion is expected to begin service in mid-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 line pipe construction. Subject to regulatory approvals, the pipeline is expected 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. The projects will be jointly funded by our General Partner at 60% and the Partnership at 40%, under a Mainline Expansion Joint Funding Agreement which parallels the Eastern Access Joint Funding Agreement. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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.

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

Enbridge, the ultimate parent of our General Partner, also announced in May 2012 complementary Eastern Access and Mainline Expansion Projects which included: (1) 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; (2) subject to regulatory approval, a reversal of Enbridge's Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec, (3) expansions to add horsepower on existing lines on the Enbridge Mainline system from western Canada to the U.S. border.

Berthold Rail

In December 2011, we announced that we will be proceeding with the Berthold Rail Project, a $145 million investment that will provide an interim solution to shipper needs in the Bakken region. The project will expand pipeline capacity into the Berthold, North Dakota Terminal by 80,000 Bpd and includes 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 an additional capacity of 10,000 Bpd to the Berthold Terminal. The loading facility and the crude oil tankage are expected to be placed into service during the first quarter of 2013.

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 the states of Montana and North Dakota and the Canadian provinces of Saskatchewan and Manitoba. The Bakken Project will follow 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 will expand 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 calls for an expansion at our existing terminal and station in Berthold, North Dakota. Upon completion in the first quarter of 2013, the Bakken Project will provide capacity of 145,000 Bpd. This project, with the North Dakota mainline, will result in a total takeaway capacity for this region of 355,000 Bpd. The United States portion of the Bakken Project will have an estimated cost of approximately $300 million. We commenced construction in July of 2011 with an expected in-service date in the first quarter of 2013. In February 2012, we and Enbridge Income Fund Holdings in Canada, announced a second open season for the Bakken Project to allow shippers the option of securing future capacity once the expansion is completed. The open season resulted in additional term commitments to support the Bakken Project.

Bakken Access Program

In October 2011, we announced the Bakken Access Program, a series of projects totaling approximately $100 million, which represents an upstream expansion that will further complement our Bakken Project, as discussed above. This expansion program will substantially enhance our gathering capabilities on the North Dakota system by 100,000 Bpd. This program is expected to be in service by mid-2013, and it involves increasing pipeline capacities, constructing additional storage tanks and adding truck access facilities at multiple locations in western North Dakota.

Cushing Terminal Storage Expansion Project

In July 2012, engineering design commenced on three new tanks and associated infrastructure totaling 936,000 barrels of incremental shell capacity at our Cushing terminal. The three additional tanks will have an estimated cost of $39 million and are targeted to be in service by the fourth quarter-2013.

In January 2012, we began construction on four new tanks at our Cushing South Terminal with an approximate shell capacity of 1.2 million barrels. As of December 31, 2012, estimated costs on the project were $33 million, and all four tanks were completed and placed into service.

During late 2010, we began construction on nine new storage tanks at our Cushing terminal with an approximate shell capacity of 3.2 million barrels. As of December 31, 2012, we spent approximately $60 million and all nine tanks were completed and placed in service.

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 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 of pipeline are targeted to be placed in service during 2013 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 Facilities Surcharge Mechanism, or 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.

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.

Flanagan South Pipeline

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 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

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 from Freeport, Texas to Cushing, Oklahoma, as well as a Texas City Terminal and Distribution System which serves refineries in Houston and Texas City areas. Seaway also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast. In the second quarter of 2012, the direction of the 500-mile Seaway pipeline was reversed to enable transportation of 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, has increased the capacity to approximately 400,000 Bpd, depending upon the mix of light and heavy grades of crude oil.

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. In addition, 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 560,000 Bpd, and subject to regulatory approval, is expected to be available in mid-2014.

Southern Access Extension

In December 2012, Enbridge announced that they will 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 a binding open season to solicit commitments from shippers for capacity on the proposed pipeline. The open season closed in January 2013 and Enbridge is evaluating the results. Prior to launching the open season, Enbridge already received sufficient capacity commitments from an anchor shipper to support the 24-inch pipeline as proposed. Subject to regulatory approval, the project is expected to be placed into service in 2015.

Other Matters

Line 6B Pipeline Integrity Plan

We completed on schedule all the work required by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, that we agreed to perform as part of our restart of Line 6B in September 2010. Additionally, a new line was installed beneath the St. Clair River in March 2011 and tied into the existing pipeline during June 2011, and we announced plans for the pipeline replacement plan discussed under *Line 6B 75-mile Replacement Program* above. Additional integrity expenditures, which could be significant, may be required after this initial remediation program. The total cost of these integrity measures is separate from the remediation, restoration and monitoring costs 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. We expect to incur ongoing operating costs for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems.

We included in the supplement to our FSM, which was effective April 1, 2011, recovery of $175 million of capital costs and $5 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 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. The pressure restrictions will remain in place until such time we can demonstrate that the root cause of the incident has been remediated.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, as well as treating and processing plants and related facilities. Collectively, these systems include:

- Approximately 11,400 miles of natural gas gathering and transmission pipelines;
- Eight active treating plants and 25 active processing plants, including two hydrocarbon dewpoint control facilities, or HCDP plants. We may idle some of these plants from time to time based on current volumes; and
- Trucks, trailers and railcars used for transporting NGLs, crude oil and other products.

The following tables set forth the operating results of our Natural Gas segment assets and approximate average daily volumes of our major systems in millions of British Thermal Units per day, or MMBtu/d, for the periods presented.

	December 31,		
	2012	2011	2010
		(in millions)	
Operating revenues	$ 3,967.7	$ 5,692.5	$ 4,230.1
Cost of natural gas	3,172.7	4,973.8	3,641.9
Environmental costs, net of recoveries	—	(0.4)	—
Operating and administrative	460.1	392.9	303.6
Depreciation and amortization	134.8	142.6	132.2
Operating expenses	3,767.6	5,508.9	4,077.7
Operating Income	$ 200.1	$ 183.6	$ 152.4
Operating Statistics (MMBtu/d)			
East Texas	1,266,000	1,378,000	1,259,000
Anadarko	1,017,000	1,013,000	711,000
North Texas	330,000	337,000	356,000
Total[1]	2,613,000	2,728,000	2,326,000

(1) Average daily volumes for the years ended December 31, 2012, 2011 and 2010 include 255,000 MMBtu/d, 251,000 MMBtu/d, and 66,000 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 derive revenue in our Natural Gas segment from the following types of arrangements:

Fee-Based and Take-or-Pay Arrangements

Under a fee-based contract, we receive a set fee for gathering, treating, processing and transporting raw natural gas and providing other similar services. These revenues correspond with the volumes and types of services we provide and do not depend directly on commodity prices. Revenues of our Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission 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 transmission volumes. Reservation fees are required to be paid whether or not the shipper delivers the volume, thus referred to as a take-or-pay arrangement. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transmission services.

Other Arrangements

We also use other types of arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales of natural gas, NGLs and condensate, and by 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 other types of arrangements we use to derive revenues for our Natural Gas business 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 then sell at market prices and retain as our fee.

- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGLs and we generally contractually provide the customer their share of NGLs regardless of actual NGL production. This type of contract may also require the processor to provide a guaranteed NGL recovery percentage to the customer.

- Percentage-of-Index Contracts—Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.

- Keep-Whole Contracts—Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw natural gas at the wellhead, we also sell for our own account at market prices, the resulting residue gas. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue natural gas with an energy content equivalent to the original raw natural gas we received as measured in British thermal units, or Btu.

Under the terms of each of these contract structures, we retain a portion of the natural gas and NGLs as our fee in exchange for providing these producers with our services. As of December 31, 2012, we are exposed to fluctuations in commodity prices in the near term on approximately 20% to 30% 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 processed natural gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate during that time. 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 unrealized 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, 2012 compared with year ended December 31, 2011

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. For the year ended December 31, 2012, prices for natural gas and NGLs declined significantly when compared to prices for the same period in 2011. Average natural gas prices declined approximately 31% per MMBtu based upon the New York Mercantile Exchange, or NYMEX, Henry Hub pricing index, for the year ended December 31, 2012, when compared to the same period in 2011. NGLs declined approximately 30% and 28% per composite barrel, for the year ended December 31, 2012 as compared to the same period in 2011, based upon the Conway and Mont Belvieu pricing hubs, respectively.

Changing industry fundamentals have resulted in significant downward pressure in current and forward NGL prices, specifically in ethane and propane. We expect the near term outlook for our Natural Gas segment will be negatively impacted by this recent decline in NGL prices, resulting in a reduction to our 2013 gross margin and the overall earnings of the Natural Gas segment.

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, 2012 increased $49.2 million from the same period in 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.

Operating income for the year ended December 31, 2012, when compared to the same period in 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 the prior year, our volumes were negatively impacted due to uncharacteristically cold weather and freezing precipitation in February 2011 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 business for the year ended December 31, 2011.

For the year ended December 31, 2012, operating income increased $13.0 million, when compared to the same period during 2011, due to fee-based contracts on our East Texas, Anadarko, and Oklahoma systems. The increase in fee-based operating income is 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.

Operating income also increased $11.2 million, for the year ended December 31, 2012 when compared to the same period in 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, operating income from our condensate marketing business for the year ended December 31, 2012 increased approximately $10.8 million, from the same period in 2011, due to higher realized margins from enhancements of facilities that were placed into service during 2012.

Operating income of our Natural Gas business experienced unrealized, 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 that caused their related earnings to become reclassified as realized, non-cash, mark-to-market gains rather than unrealized. 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 same period of 2011. 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.

The following table depicts the effect that unrealized, non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the years ended December 31, 2012 and 2011:

	For the years ended December 31,	
	2012	2011
	(in millions)	
Hedge ineffectiveness	$ 3.1	$ (5.3)
Non-qualified hedges	1.2	21.1
Derivative fair value gains	$ 4.3	$ 15.8

Operating and administrative costs of our Natural Gas segment were $67.2 million higher for the year ended December 31, 2012 compared to the same period in 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 to write down project line pipe to net realizable value, as well as, expense development, engineering and other costs associated with a project in East Texas. Due to lower levels of producer activity in the East Texas region, this project was deferred to a later date and it was determined that these costs and line pipe have uncertain future benefit. As such, these costs were expensed and the line pipe written down for the year ended December 31, 2012. There were no similar adjustments for the same period in 2011.

Depreciation expense for our Natural Gas segment decreased $7.8 million, for the year ended December 31, 2012 compared with the same period of 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 same period of 2011. This decrease was offset with an increase in depreciation expense associated with additional assets that were put in service during late 2011.

Year ended December 31, 2011 compared with year ended December 31, 2010

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. We were exposed to fluctuations in commodity prices in the near term on approximately 30% to 40% of the natural gas, NGLs and condensate we expected to receive as compensation for our services. As a result of 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. NGL prices were higher for the year ended December 31, 2011 compared to prices in the same period in 2010, which positively impacted our operating income by $58.9 million due to the move favorable pricing environment.

Our volumes and revenues are the result of wellhead supply contracts and drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend, Barnett Shale, Granite Wash and the Haynesville Shale. During the year ended December 31, 2011, natural gas volumes on our systems increased approximately 17%, in relation to the same period of 2010, primarily due to production increases in the Granite Wash and new assets placed in service to capture the growing production from the Haynesville shale play. Volumes on our Anadarko system increased 42% for the year ended December 31, 2011 compared with the same period in 2010, of which the majority of the increase was associated with the Elk City system we acquired in September 2010 representing an additional 185,000 MMBtu/d.

Although volumes were higher on the majority of our systems for the year ended December 31, 2011 compared with the same period of 2010, in February 2011 uncharacteristically cold weather and freezing precipitation moved through Oklahoma and north Texas with temperatures dropping below freezing for extended periods. These conditions resulted in mechanical issues with our producers' equipment and impacted their ability to flow natural gas. Producers shut in significant volumes during this period, which reduced the average daily volumes on our systems by approximately 56,000 MMBtu/d, in the first quarter of 2011, or approximately 14,000 MMBtu/d for the year ended December 31, 2011. 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 business for year ended December 31, 2011.

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, 2011 was $41.5 million, representing a decrease of $24.4 million from the $65.9 million we produced for the same period in 2010.

The reduction in keep-whole earnings was a result of the increasing production of liquids rich natural gas on our Anadarko system, excluding the Elk City acquisition, where a significant number of our contracts are POL type arrangements. This earnings decrease is largely attributable to paying natural gas producers for liquids we were unable to recover due to gas volume increasing faster than our available capacity. The rapid increase in supply exceeded our processing capacity as evidenced by the 18% increase in average daily volumes from 645,000 MMBtu/d to 762,000 MMBtu/d on the system for the year ended December 31, 2011 compared to the same period last year.

Changes in the average forward prices of natural gas, NGLs and condensate from December 31, 2010 to December 31, 2011 produced unrealized, non-cash, mark-to-market net gains of $15.8 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. The net gains resulted primarily from the fractionation hedge gains on the settlement of our 2011 hedge losses as well as gains on the market movement on new fractionation hedges, offset by losses on the settlement of 2011 gas hedges.

Comparatively, changes in the average forward prices of natural gas, NGLs and condensate from December 31, 2009 to December 31, 2010, produced unrealized, non-cash, mark-to-market net gains of $4.4 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. The average forward and daily prices for natural gas at December 31, 2010 were lower relative to natural gas prices at December 31, 2009, while the average forward and daily prices of NGLs were higher though the end of 2012 and lower thereafter relative to NGL prices at December 31, 2009. As a result of the lower natural gas forward prices, we experienced unrealized mark-to-market net gains on derivatives we use to fix the price of natural gas we sell. Partially offsetting the gains were unrealized mark-to-market net losses on the derivatives that we use to hedge our fractionation margins, which represent the relative difference between the price we receive from the sale of NGLs and the corresponding cost of natural gas we purchase for processing. As a result of lower natural gas forward prices and the higher NGL forward prices, fractionation margins widened producing these derivative losses.

The following table depicts the effect that unrealized, non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the years ended December 31, 2011 and 2010:

	For the years ended December 31,	
	2011	**2010**
	(in millions)	
Hedge ineffectiveness	$ (5.3)	$ 3.5
Non-qualified hedges	21.1	0.9
Derivative fair value gains	$ 15.8	$ 4.4

Operating and administrative costs of our Natural Gas segment were $89.3 million higher for the year ended December 31, 2011 compared to the same period in 2010, primarily due to the expansion of our systems, including the Elk City system we acquired in September 2010 and a common carrier trucking company we acquired in October 2010. Increased maintenance costs and workforce related costs for the year ended December 31, 2011 when compared to the same period in 2010 also contributed to the increased operating and administrative costs.

Depreciation expense for our Natural Gas segment increased $10.4 million for the year ended December 31, 2011 compared to the same period in 2010, primarily due to an increase in depreciation associated with the Elk City system we acquired in September 2010 and additional assets that were put in service during 2010. This increase was partially offset by a revision in depreciation rates for the Anadarko, North Texas and East Texas systems effective July 1, 2011, which extended the depreciable lives of the systems and lowered depreciation expense approximately $17.0 million.

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 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 will be placed into service in future periods.

Project	Estimated Capital Costs (in millions)	Expected In-service Date	Funding
Texas Express Pipeline	$385	Mid 2013	Joint[1]
Ajax Cryogenic Processing Plant	$230	Mid 2013	EEP

(1) Our ownership of the Texas Express Pipeline is 35%. Estimated capital cost presented is only our portion of the costs.

Texas Express Pipeline

In September 2011, we announced a joint venture among us, Enterprise Products, and Anadarko Petroleum Corporation, or Anadarko, to design and construct a new NGL pipeline and two new NGL gathering systems, collectively referred to as the Texas Express Pipeline project, or TEP. In April 2012, DCP Midstream LLC, or DCP, announced plans to purchase a 10% ownership in the NGL pipeline portion of TEP from Enterprise Products. After DCP's purchase, the NGL pipeline portion of TEP is owned 35% by Enterprise Products, 35% by us, 20% by Anadarko and 10% by DCP, while the ownership in the two new NGL gathering systems will be owned 45% by Enterprise Products, 35% by us and 20% by Anadarko. Our portion of the total estimated cost is

$385 million. The pipeline will originate at Skellytown, Texas and extend approximately 580-miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. The pipeline will have an initial capacity of approximately 280,000 Bpd and will be readily expandable to approximately 400,000 Bpd. Approximately 250,000 Bpd of capacity has been subscribed on the pipeline.

In addition, the TEP joint venture project will include two new NGL gathering systems. The first will connect TEP NGL pipeline to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and Western Oklahoma. The second NGL gathering system will connect the new pipeline to central Texas, Barnett Shale processing plants. Volumes from the Rockies, Permian Basin and Mid-Continent regions will be delivered to the TEP 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 will be able to access TEP through the connecting Front Range Pipeline as proposed by Enterprise Products, DCP and Anadarko. Enterprise Products will construct and serve as the operator of the pipeline, while we will build and operate the new gathering systems. The pipeline and portions of the gathering systems are expected to begin service in mid-2013, subject to regulatory approvals and finalization of commercial agreements.

TEP will serve as a link between growing supply sources of NGLs in the Anadarko region and the primary end use market on the United States Gulf Coast and will provide guaranteed NGL access to the primary United States petrochemical market located in Mont Belvieu. TEP will assist us in fulfilling our strategic objective of expanding our presence in the natural gas and NGL value chain and provide us with a new source of strong and stable cash flow.

Ajax Cryogenic Processing Plant

In August 2011, we announced plans to construct an additional processing plant and other facilities, including compression and gathering infrastructure, on our Anadarko system at a cost of $230 million, which we refer to as our Ajax Plant. The Ajax Plant has a planned capacity of 150 million cubic feet per day, or MMcf/d, and is intended to meet the continued strength of horizontal drilling activity in this area. The Ajax Plant is anticipated to be in service in mid-2013.

The Ajax plant, when operational, in addition to the Allison Plant, will increase the total processing capacity on our Anadarko system to approximately 1,200 MMcf/d.

South Haynesville Shale Expansion

In February 2010, we announced plans to expand our East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville Shale, together with a large diameter lateral pipeline from Shelby County to Carthage which will further expand our recently completed Shelby County Loop. The expansion into the Haynesville Shale area increased the capacity of our East Texas system by 900 MMcf/d. We completed construction of a portion of the pipeline for the project during the second quarter of 2010 and the main trunkline to Carthage in December 2010. Construction of the facilities was completed in the second quarter of 2012.

In April 2011, we announced plans to invest an additional $175 million to expand our East Texas system. We have signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville Shale to provide gathering, treating and transmission services in Shelby, San Augustine and Nacogdoches counties. The projects involve construction of gathering and related market outlet pipelines and related treating facilities in the Texas Haynesville Shale. Due to lower levels of producer activity, in light of weak natural gas prices, the Partnership has deferred portions of its Haynesville natural gas expansion pending increases in drilling activity.

Other Matters

Elk City System Acquisition

On September 16, 2010, we acquired 100% ownership of the entities that comprise the Elk City system for $686.1 million in cash, including amounts for working capital. The Elk City system extends from southwestern Oklahoma to Hemphill County in the Texas Panhandle. The Elk City system consists of approximately 800 miles of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 million cubic feet per day, or MMcf/d, and a combined current natural gas liquid production capability of 20,000 barrels per day. The acquisition of the Elk City system complements our existing Anadarko natural gas system by providing additional processing capacity and expansion capability. The results of operations of the Elk City system have been included in our consolidated financial statements within our Natural Gas segment from the September 16, 2010 acquisition date.

Marketing

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

	December 31,		
	2012	2011	2010
		(in millions)	
Operating revenues	$ 1,392.6	$ 2,131.9	$ 2,334.2
Cost of natural gas	1,397.4	2,126.3	2,321.4
Operating and administrative	6.6	6.3	8.9
Depreciation and amortization	—	0.1	0.2
Operating expenses	1,404.0	2,132.7	2,330.5
Operating income (loss)	$ (11.4)	$ (0.8)	$ 3.7

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, 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 same period in 2011 primarily due to the continued erosion of natural gas prices and associated differentials.

Natural gas prices during 2012 were lower and relatively stable as compared to the same period of 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 same period in 2011.

Included in the operating results of our Marketing segment for the year ended December 31, 2012 were unrealized, non-cash, mark-to-market net losses of $3.1 million as compared with $0.7 million of unrealized non-cash, mark-to-market net gains for the same period in 2011 associated with derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. This increase in unrealized, non-cash, mark-to-market net losses for the year ended December 31, 2012, as compared to the same period in 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.

Year ended December 31, 2011 compared with year ended December 31, 2010

The operating results of our Marketing segment for the year ended December 31, 2011 decreased by $4.5 million when compared to the same period in 2010.

Included in the operating results of our Marketing segment for the year ended December 31, 2011 were unrealized, non-cash, mark-to-market net gains of $0.7 million associated with derivative financial instruments that did not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the $6.7 million of unrealized non-cash, mark-to-market net losses for the same period in 2010. For the year ended December 31, 2011, the non-cash, mark-to-market net gains primarily resulted from financial instruments that we used to hedge our storage positions. The net gains associated with our storage derivative instruments resulted from the narrowing 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. Comparatively, for the year ended December 31, 2010, the non-cash, mark-to-market net loss primarily resulted from the realizations of financial transactions entered into in prior years and realized in 2010.

Offsetting the unrealized, non-cash, mark-to-market net gains and contributing to the operating loss of our Marketing segment were relatively stable natural gas prices during 2011, which limited opportunities to benefit from significant price differentials between market centers.

Operating income for the year ended December 31, 2011 was also negatively affected by non-cash charges of $2.8 million we recorded to reduce the cost basis of our natural gas inventory to net realizable value compared to $1.0 million of similar charges in the comparable period of 2010.

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.

	December 31,		
	2012	2011	2010
		(in millions)	
Operating and administrative expenses	$ 2.3	$ 2.2	$ 4.1
Operating loss	(2.3)	(2.2)	(4.1)
Interest expense	345.0	320.6	274.8
Other income	10.0	6.5	17.5
Income tax expense	8.1	5.5	7.9
Net loss	(345.4)	(321.8)	(269.3)
Net loss attributable to Noncontrolling interest	57.0	53.2	60.6
Net loss attributable to general and limited partners	$ (402.4)	$ (375.0)	$ (329.9)

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	**2011**
	(in millions)	
Interest expense	$ 345.0	$ 320.6
Interest capitalized	36.3	13.6
Interest cost incurred	$ 381.3	$ 334.2
Interest cost 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*.

Year ended December 31, 2011 compared with year ended December 31, 2010

The increase in our net loss in 2011 was mostly attributable to the increase in interest expense as compared to the same period in 2010. This increase in interest expense is primarily the result of a higher weighted average outstanding debt balance during the year ended December 31, 2011 as compared with the same period in 2010. The increased weighted average outstanding debt balance was primarily a result of the following:

- An increase in our weighted average balance of commercial paper outstanding for the year ended December 31, 2011 of $706.3 million compared to $328.3 million during the same period in 2010; and

- 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.

For the year ended December 31, 2011, we recorded $0.8 million of unrealized, non-cash, mark-to-market net losses associated with the changes in fair value of these derivatives that resulted from the decrease in interest rates from December 31, 2010 to December 31, 2011. For the year ended December 31, 2010, we recorded $1.0 million of unrealized, non-cash, mark-to-market net losses associated with the changes in fair value of these derivatives that resulted from the decrease in interest rates from December 31, 2009 to December 31, 2010.

Our interest cost for the years ended December 31, 2011 and 2010 is detailed below:

	December 31,	
	2011	**2010**
	(in millions)	
Interest expense	$ 320.6	$ 274.8
Interest capitalized	13.6	8.7
Interest cost incurred	$ 334.2	$ 283.5
Interest cost paid	$ 314.3	$ 257.6
Weighted average interest rate	*6.4%*	*6.4%*

Our income tax expense is $5.5 million and $7.9 million for the years ended December 31, 2011 and 2010, respectively, 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.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement and Regulatory Accounting

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 $53.9 million, $53.2 million and $60.6 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the years ended December 31, 2012, 2011 and 2010, 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.

In connection with our application of the regulatory accounting provisions to our Alberta Clipper Pipeline, we recorded AEDC in "Other income (expense)" on our consolidated statement of income. For the year ended December 31, 2010, we recorded $15.3 million and $4.8 million, of AEDC and AIDC, or allowance for interest during construction, respectively, on our consolidated statements of income related to the Alberta Clipper Pipeline. There were no additional costs recorded in 2012 or 2011 as all assets were placed into service as of December 31, 2010.

Proceeds from Claim Settlements

We received proceeds of $11.6 million, in 2011, 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. There were no similar transactions in 2012.

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 $2.0 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 $675.0 million credit agreement with JPMorgan Chase Bank as administrative agent, and a syndicate of 12 lenders, 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 access our commercial paper program 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.

As set forth in the following table, we had approximately $1.5 billion of liquidity available to us at December 31, 2012 to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental costs resulting from the crude oil releases on Lines 6A and 6B.

	(in millions)
Cash and cash equivalents	$ 227.9
Total credit available under Credit Facilities	2,675.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper issuances	1,160.0
Letters of credit outstanding	231.8
Total	$ 1,511.1

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. 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, 2012, we had a working capital deficit of approximately $546.1 million and over $1.5 billion of liquidity to meet our ongoing operational, investing and finance needs as of December 31, 2012 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.

Issuance of Class A Common Units

The following table presents the net proceeds from our Class A common unit issuances for cash for the years ended December 31, 2012, 2011 and 2010 other than pursuant to the Equity Distribution Agreement, or EDA, and the Amended and Restated Equity Distribution Agreement, or Amended EDA described below.

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
2010					
November[(5)(6)]	11,960,000	$30.06	$ 347.4	$ 7.4	$ 354.8

(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.

(5) The proceeds from the November 2010 equity issuance were used to repay short term indebtedness incurred to finance the Elk City system acquisition and capital expansion projects.

(6) Amounts adjusted for the April 21, 2011 stock split.

Equity Distribution Agreement

In June 2010, we entered into the 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 EDA and remained unsold as of that date.

On May 27, 2011, the Partnership entered into the 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 years ended December 31, 2012 and 2011:

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
2010					
April 1 to June 30[3]	574,690	$ 26.26	$ 14.8	$ 0.3	$ 15.1
July 1 to September 30[3]	1,373,482	$ 27.11	36.3	0.7	37.0
October 1 to December 31[3]	289,230	$ 27.85	7.6	0.2	7.8
2010 Totals[3]	2,237,402		$ 58.7	$ 1.2	$ 59.9

(1) Net of commissions and issuance costs of $2.2 million and $1.2 million for the years ended December 31, 2011 and 2010, respectively.

(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.

Investments

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 that permits aggregate borrowings of up to, at any one time outstanding, $2.0 billion, a letter of credit subfacility and a swing line subfacility. Effective September 26, 2012, we extended the maturity date to September 26, 2017 and amended it to adjust the base interest rates.

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 $675.0 million: 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.

On February 8, 2013, we amended the $675 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $1.1 billion. We use the unsecured revolving credit agreement to fund our general activities and working capital needs. The amended $1.1 billion credit agreement has terms consistent with our 364-Day Credit Facility. After this amendment, our Credit Facilities provide an aggregate amount of $3.1 billion of bank credit.

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, 2012, we could borrow $1,283.2 million under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$ 2,675.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	1,160.0
Letters of credit outstanding	231.8
Total amount we could borrow at December 31, 2012	$ 1,283.2

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, 2010, we renewed LIBOR rate borrowings of $1,284.0 million, on a non-cash basis.

Effective September 30, 2011, our Credit Facility was amended to further modify the definition of Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, as set forth in the terms of our Credit Facility, to increase from $550 million to $650 million, the aggregate amount of the costs associated with the crude oil releases on Lines 6A and 6B that are excluded from the computation of Consolidated EBITDA. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue. As of December 31, 2012, we were in compliance with the terms of our financial covenants.

Commercial Paper

At December 31, 2012, we had $1.2 billion of commercial paper outstanding at a weighted average interest rate of 0.46%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $884.9 million during the year ended December 31, 2012, which include gross borrowings of $9,141.6 million and gross repayments of $8,256.7 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. Our commercial paper program was increased from $1.0 billion in August 2011.

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 $300.0 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 $300.0 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.

In September 2011, we issued and sold $600.0 million in aggregate principal amount of senior notes due 2021, which we refer to as the 2021 Notes. The 2021 Notes bear interest at the rate of 4.20% per year and will mature on September 15, 2021. Interest on the 2021 Notes is payable on March 15 and September 15 of each year, beginning on March 15, 2012. Also in September 2011, we issued and sold an additional $150.0 million in aggregate principal amount of our 5.50% notes due in 2040, which we refer to as the 2040 Notes. The additional 2040 Notes will be fully fungible with, rank equally in right of payment with and form a part of the same series as the existing 2040 Notes, originally issued by us in September 2010, for all purposes under the governing indenture. We received net proceeds from the note offerings in September 2011 of approximately $740.7 million after payment of underwriting discounts and commissions and our estimated offering expenses. We used the net proceeds from these offerings to repay a portion of our outstanding commercial paper, to fund a portion of our capital expansion projects and for general corporate purposes.

Junior Subordinated Notes

The Junior Subordinated Notes, which we refer to as the Junior Notes, consist of our 8.05% fixed/floating rate, unsecured, long-term junior subordinated notes due 2067, with a principal amount outstanding of $400.0 million. The Junior Notes are subordinate in right of payment to all of our existing and future senior indebtedness, as defined in the related indenture.

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 funded through Enbridge, 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, 2012, we had approximately $330.0 million outstanding under the A1 Term Note.

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. No such contributions were made for the year ended December 31, 2012. The OLP paid a distribution of $59.9 million and $76.4 million to our General Partner and its affiliate during the years ended December 31, 2012 and 2011 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 $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, 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, 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. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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 $347.9 million to the OLP during the year ended December 31, 2012 to fund its equity portion of the construction costs associated with the Eastern Access Projects.

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. 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. We also have an option, exercisable prior to June 30, 2013, for the Partnership to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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 $3.0 million to the OLP during the year ended December 31, 2012 to fund its equity portion of the construction costs associated with the Mainline Expansion Projects.

Restrictive Covenants

Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.00 to 1.00. At December 31, 2012, we were in compliance with the covenants associated with our Credit Facility. Our Credit Facility also places limitations on the debt that 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, 2012.

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, 2012.

Cash Requirements

Capital Spending

We expect to make additional expenditures during 2013 for the acquisition and construction of natural gas processing and crude oil transportation infrastructure. In 2013, we expect to spend approximately $3.4 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 $ 1.1 billion from our General Partner based on our joint funding arrangement for the Eastern Access Projects and Mainline Expansion Projects. We made expenditures of $2.0 billion for the year ending December 31, 2012, inclusive of $168.5 million in contributions to the Texas Express Pipeline and $350.9 million of expenditures that were financed by contributions from our General Partner via the joint funding arrangement. At December 31, 2012, we had approximately $681.3 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. Given sustained natural gas prices and weaker NGL prices for ethane and propane, our Natural Gas business will face challenges over our near-term planning horizon. As such, with our focus to exercise prudent financial management and optimize our capital, we plan to reduce capital investment into the natural gas business in the near term. We will continue to consider opportunities in the natural gas business that will elevate our long-term, fee-based profile or strengthen our existing assets.

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, 2013. Although we anticipate making these expenditures in 2013, 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 $2.0 billion, including $123.8 million on core maintenance activities, for the year ended December 31, 2012. For the full year ending December 31, 2013, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in millions)
Capital Projects	
Eastern Access Projects	$ 1,395
U.S. Mainline Expansions	510
North Dakota Expansion Program	205
Line 6B 75-mile Replacement Program	95
Liquids Integrity Program	285
Ajax Cryogenic Processing Plant	55
System Enhancements	565
Core Maintenance Activities	130
Joint Venture Projects	
Texas Express Pipeline	185
	3,425
Less: Joint Funding by General Partner	1,145
	$ 2,280

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.

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 of pipeline are targeted to be placed in service during 2013 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.

We completed on schedule all the work required by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, that we agreed to perform as part of our restart of Line 6B in September 2010. Additionally, a new line was installed beneath the St. Clair River in March 2011 and tied into the existing pipeline during June 2011, and we announced plans for the pipeline replacement plan discussed under *Line 6B 75-mile Replacement Program*. Additional integrity expenditures, which could be significant, may be required after this initial remediation program. The total cost of these integrity measures is separate from the remediation, restoration and monitoring costs 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. We expect to incur ongoing operating costs for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems.

We included in the supplement to our FSM, which was effective April 1, 2011, recovery of $175 million of capital costs and $5 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.

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 2012, our cash flows were impacted by the approximate $135.2 million we paid for the environmental remediation, restoration and cleanup activities, excluding recognized insurance recoveries of $170.0 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. We have revised our disclosed estimate for repair and remediation related costs associated with this crude oil release to approximately $10.5 million, inclusive of approximately $1.6 million of 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.

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, 2012 for each of the indicated calendar years:

	Notional	2013	2014	2015	2016	2017	Total[4]
			(in millions)				
Swaps							
Natural gas[1]	66,174,081	$ 8.7	$ 0.2	$ —	$ —	$ —	$ 8.9
NGL[2]	3,758,810	0.8	(1.8)	0.5	—	—	(0.5)
Crude Oil[2]	3,976,055	(2.3)	2.7	6.6	0.5	—	7.5
Options							
Natural gas—puts purchased[1]	1,642,500	1.4	—	—	—	—	1.4
NGL—puts purchased[2]	584,750	3.7	1.3	—	—	—	5.0
Crude Oil —puts purchased[2]	—	—	—	—	—	—	—
Forward contracts							
Natural gas[1]	45,330,882	0.9	0.5	0.4	0.1	—	1.9
NGL[2]	13,141,045	3.1	—	—	—	—	3.1
Crude Oil[2]	1,565,122	2.6	—	—	—	—	2.6
Power[3]	101,532	(0.5)	(0.8)	—	—	—	(1.3)
Totals		$ 18.4	$ 2.1	$ 7.5	$ 0.6	$ —	$ 28.6

(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 $0.4 million of losses at December 31, 2012.

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, 2012 for each of the indicated calendar years:

	Notional Amount	2013	2014	2015	2016	2017	Thereafter	Total[(1)]
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$ 2,425.0	$ (25.4)	$ (8.9)	$ (7.1)	$ (5.6)	$ (2.9)	$ —	$ (49.9)
Fixed to Floating	$ 125.0	2.4	—	—	—	—	—	2.4
Pre-issuance hedges	$ 2,350.0	(238.4)	(45.3)	—	8.4	—	—	(275.3)
		$ (261.4)	$ (54.2)	$ (7.1)	$ 2.8	$ (2.9)	$ —	$ (322.8)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $13.7 million of gains at December 31, 2012.

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 2012, we distributed a total of 2,632,090 i-units through quarterly distributions to Enbridge Management, compared with 2,420,228 and 2,507,688 in 2011 and 2010, respectively.

The following table represents cash we have retained in our business since January 2010 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)	
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
2010			
November 12	$ 17.9	$ 0.3	$ 18.2
August 13	17.5	0.4	17.9
May 14	16.7	0.4	17.1
February 12	16.2	0.3	16.5
	$ 68.3	$ 1.4	$ 69.7

Our current annual cash distribution rate is $2.174 per unit, or $0.54350 per quarter, for the year ended December 31, 2012 compared with $2.130 per unit, or $0.53250 per quarter, for the year ended December 31, 2011. 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 New 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, 2012, 2011 and 2010 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)	
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
2010				
October 27	November 12	$ 10.7	$ 21.4	$ 32.1
July 23	August 13	8.6	17.2	25.8
		$ 19.3	$ 38.6	$ 57.9

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2012:

	2013	2014	2015	2016	2017	Thereafter	Total
				(in millions)			
Long-term debt and notes payable to affiliates	$ 212.0	$ 212.0	$ 12.0	$ 312.0	$ 1,172.0	$ 4,120.0	$ 6,040.0
Purchase commitments(1)	720.5	—	—	—	—	—	720.5
Power commitments(2)	4.1	0.5	—	—	—	—	4.6
Other operating leases	24.4	23.7	22.2	21.5	20.6	100.2	212.6
Right-of-way(3)	3.4	3.2	3.1	2.7	1.9	44.3	58.6
Product purchase obligations(4)	163.0	15.2	9.8	—	—	—	188.0
Transportation/Service contract obligations(5)	35.6	43.4	42.4	39.5	79.0	551.2	791.1
Fractionation agreement obligations(6)	36.1	43.3	43.3	43.3	43.3	219.7	429.0
Total	$ 1,199.1	$ 341.3	$ 132.8	$ 419.0	$ 1,316.8	$ 5,035.4	$ 8,444.4

(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 $1.9 million to $3.4 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 2017.

(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, 2012, 2011 and 2010 were $388.7 million, $275.4 million and $656.3 million, respectively.

Cash Flow Analysis

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

	For the year ended December 31, 2012	For the year ended December 31, 2011	Variance 2012 vs. 2011 Increase (Decrease)
	(in millions)		
Total cash provided by (used in):			
Operating activities	$ 851.0	$ 1,045.6	$ (194.6)
Investing activities	(1,906.6)	(1,099.0)	(807.6)
Financing activities	860.6	331.4	529.2
Net increase (decrease) in cash and cash equivalents	(195.0)	278.0	(473.0)
Cash and cash equivalents at beginning of year	422.9	144.9	278.0
Cash and cash equivalents at end of period	$ 227.9	$ 422.9	$ (195.0)

Operating Activities

Net cash provided by our operating activities decreased $194.6 million for the year ended December 31, 2012, compared to the same period in 2011, primarily due to:

- Decrease in net income of $127.1 million and non-cash items which primarily consisted of a $48.6 million decrease in derivative fair value gains, which were offset by a $98.6 million decrease in environmental costs, net of recoveries and $17.5 million in other general costs and expenses;

- Payment of $18.8 million to settle interest rate derivatives in 2011 that did not occur in 2012; and

- Lower changes in our working capital accounts of $25.7 million for the year ended December 31, 2012 compared with the same period in 2011, which were affected by general timing differences in the collection on, and payment of our current and related party accounts. The changes in the working capital accounts for the year ended December 31, 2012, were also affected by a decrease of $192.0 million in environmental costs paid, which primarily consisted of expenses related to Line 6B, with $134.0 million spent in 2012, compared to $276.6 million for the same period in 2011.

Investing Activities

Net cash used in our investing activities for the year ended December 31, 2012 increased by $807.6 million, compared to the same period of 2011, primarily due to additions to property, plant and equipment in 2012 related to various enhancement projects. We also made cash contributions to our joint venture project, Texas Express Pipeline, of $168.5 million for the year ended December 31, 2012.

Financing Activities

The net cash provided by our financing activities increased $529.2 million during the year ended December 31, 2012 compared to the same period in 2011 primarily due to the following:

- Increase in net borrowings on our commercial paper of $1,494.7 million; and
- Increase of $347.6 million in capital contributions from our General Partner and its affiliates for its ownership interest in Eastern Access Projects and Mainline Expansion Projects.

Offsetting the increases were the following decreases:

- Decrease in net proceeds of $424.4 million related to Class A common units, which included $9.4 million in contributions from the General Partner related to these issuances to maintain its 2% interest;
- Increase of cash used of $94.6 million for distributions to our partners in 2012;
- Decrease in debt issuances of $740.7 million related to issuance of senior notes in 2011 that did not occur in 2012; and
- Increase of $69.0 million in repayments of debt.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On January 30, 2013, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2013. The distribution was paid to unitholders of record as of February 7, 2013, of our available cash of $198.9 million at December 31, 2012, or $0.54350 per limited partner unit. Of this distribution, $176.1 million was paid in cash, $22.4 million was distributed in i-units to our i-unitholder and $0.4 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, 2013, 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 $13.8 million to the noncontrolling interest in the Series AC, while $6.9 million was paid to us.

Credit Agreement Amendment

On February 8, 2013, we amended the $675 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $1.1 billion. We use the unsecured revolving credit agreement to fund our general activities and working capital needs. The amended $1.1 billion credit agreement has terms consistent with our 364-Day Credit Facility. After this amendment, our Credit Facilities provide an aggregate amount of $3.1 billion of bank credit.

REGULATORY MATTERS

FERC Transportation Tariffs

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.

Effective April 1, 2011, we filed our annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2011 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. Also included was a supplement to our FSM for recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Note 13. *Commitments and Contingencies—Line 6B Pipeline Integrity Plan*.

This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.21 per barrel, to an average of approximately $1.76 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.

On May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in western Canada on Enbridge Pipelines Inc., or Enbridge Pipeline's, Canadian Mainline system to all delivery points on the Lakehead Pipeline system owned by the OLP and delivery points on the Canadian Mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

Effective July 1, 2011, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65% (PPI-FG + 2.65%) should be the oil pricing index for the five year period ending July 2016. The index is used to establish rate ceiling levels for oil pipeline rate changes. The increase in rates is due to an increase in the Producer Price Index for Finished Goods as compared with prior periods. For our Lakehead system, indexing applies only to the base rates and does not apply to the System Expansion Program Phase II, or SEP II, Terrace and Facilities surcharges, which include the Southern Access and Alberta Clipper pipelines.

Effective December 19, 2011, we modified the terms of our transportation tariff on our Ozark system to implement a lottery process to allocate new shipper capacity if and when the number of new shippers nominating on the system precludes any individual new shipper from being allocated a minimum batch. Additionally, we increased the minimum accepted batch size from 10,000 barrels per day, or Bpd, to 30,000 Bpd to ensure accurate delivery measurement.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Balance Sheet Offsetting

In December 2011, the Financial Accounting Standards Board, or FASB, issued Accounting Standards No. 2011-11, *Disclosures about Offsetting Assets and Liabilities*, as part of the FASB's joint project with the IASB, which requires an entity to disclose information about offsetting and related arrangements. The standard will enable users of financial statements to understand the effect that offsetting and related arrangements have on an entity's financial position. The standard will be effective for annual reporting periods beginning on or after January 1, 2013, with required disclosures presented retrospectively for all comparative period presented. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

In January 2013, the FASB issued Accounting Standards No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, which highlights the scope of transactions that are subject to the disclosures about offsetting. The standard clarifies that ordinary trade receivables and receivables are not in the scope of Accounting Standards No. 2011-11, *Disclosures about Offsetting Assets and Liabilities*, discussed above, but applies only to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in FASB Accounting Standards Codification or subject to a master netting arrangement or similar agreement. The standard will enable users of financial statements to understand the effect that offsetting and related arrangements have on an entity's financial position. The standard will be effective for annual reporting periods beginning on or after January 1, 2013, with required disclosures, presented retrospectively, for all comparative periods presented. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Accounting Standards Update—Accumulated Other Comprehensive Income

In February 2013, the FASB issued Accounting Standards No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*, which does not change the current requirements for reporting net income or other comprehensive income in financial statements. The standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. The entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. The standard is effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. 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.

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 must 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.

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.

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 began including a portion of our capital expenditures for well-connects associated with our natural gas system assets as core maintenance expenditures beginning in 2009.

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, capitalized are certain costs 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 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. 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 debt and 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 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"
- 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 of 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.

Derivative financial instruments qualifying for hedge accounting treatment that we use are cash flow hedges. 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. 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, for derivative financial instruments that do not qualify for hedge accounting. 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 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.

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.

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, 2012 and 2011.

	December 31, 2012									December 31, 2011	
	Average Interest Rate	Expected Maturity of Carrying Amounts by Fiscal Year							Fair Value	Carrying Amount	Fair Value
		2013	2014	2015	2016	2017	Thereafter	Total			
	(dollars in millions)										
Liabilities											
Fixed Rate:											
Senior Notes due 2012	7.900%	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 100.0	$ 106.1
Senior Notes due 2013	4.750%	$ 200.0	$ —	$ —	$ —	$ —	$ —	$ 200.0	$ 203.9	$ 199.9	$ 209.6
Senior Notes due 2014	5.350%	$ —	$ 200.0	$ —	$ —	$ —	$ —	$ 200.0	$ 215.6	$ 200.0	$ 218.9
Senior Notes due 2016	5.875%	$ —	$ —	$ —	$ 299.9	$ —	$ —	$ 299.9	$ 345.1	$ 299.9	$ 346.2
Senior Notes due 2018	7.000%	$ —	$ —	$ —	$ —	$ —	$ 99.9	$ 99.9	$ 124.6	$ 99.9	$ 123.8
Senior Notes due 2018	6.500%	$ —	$ —	$ —	$ —	$ —	$ 398.8	$ 398.8	$ 484.1	$ 398.7	$ 481.5
Senior Notes due 2019	9.875%	$ —	$ —	$ —	$ —	$ —	$ 500.0	$ 500.0	$ 710.5	$ 500.0	$ 715.1
Senior Notes due 2020	5.200%	$ —	$ —	$ —	$ —	$ —	$ 499.9	$ 499.9	$ 575.4	$ 499.8	$ 563.0
Senior Notes due 2021	4.200%	$ —	$ —	$ —	$ —	$ —	$ 598.9	$ 598.9	$ 644.2	$ 598.8	$ 620.8
Senior Notes due 2028	7.125%	$ —	$ —	$ —	$ —	$ —	$ 99.8	$ 99.8	$ 137.5	$ 99.8	$ 134.6
Senior Notes due 2033	5.950%	$ —	$ —	$ —	$ —	$ —	$ 199.8	$ 199.8	$ 244.2	$ 199.7	$ 238.1
Senior Notes due 2034	6.300%	$ —	$ —	$ —	$ —	$ —	$ 99.8	$ 99.8	$ 126.5	$ 99.8	$ 123.5
Senior Notes due 2038	7.500%	$ —	$ —	$ —	$ —	$ —	$ 399.0	$ 399.0	$ 573.8	$ 399.0	$ 563.5
Senior Notes due 2040	5.500%	$ —	$ —	$ —	$ —	$ —	$ 546.3	$ 546.3	$ 605.5	$ 546.2	$ 594.7
Junior subordinated notes due 2067	8.050%	$ —	$ —	$ —	$ —	$ —	$ 399.6	$ 399.6	$ 453.6	$ 399.6	$ 435.5
Variable Rate:											
Commercial Paper	0.460%	$ —	$ —	$ —	$ —	$ 1,160.0	$ —	$ 1,160.0	$ 1,160.0	$ 275.0	$ 275.0

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.

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, 2012.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value December 31, 2012	Fair Value December 31, 2011
			(dollars in millions)		
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 800	3.24%	$ (22.6)	$ (42.2)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$ 125	4.35%	$ (2.2)	$ (6.8)
Interest Rate Swaps—Pay Float	Non-qualifying	$ 125	4.75%	$ 2.4	$ 7.5
Contracts maturing in 2014					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 200	0.56%	$ (0.6)	$ 0.2
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 300	2.43%	$ (6.7)	$ (4.7)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.21%	$ (16.0)	$ (5.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 500	2.08%	$ (1.8)	$ —
Contracts settling prior to maturity					
2012—Pre-issuance Hedges	Cash Flow Hedge	$ 600	4.56%	$ (154.0)	$ (123.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.98%	$ (84.4)	$ (63.1)
2014—Pre-issuance Hedges	Cash Flow Hedge	$ 750	3.15%	$ (45.3)	$ (23.4)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 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, 2012 and 2011, 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 $13.7 million of gains at December 31, 2012 and $19.4 million of gains at December 31, 2011

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, 2012 for each of the indicated calendar years:

	Notional Amount	2013	2014	2015	2016	2017	Thereafter	Total[1]
				(in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$2,425.0	$ (25.4)	$ (8.9)	$ (7.1)	$ (5.6)	$ (2.9)	$ —	$ (49.9)
Fixed to Floating	$ 125.0	2.4	—	—	—	—	—	2.4
Pre-issuance hedges	$2,350.0	(238.4)	(45.3)	—	8.4	—	—	(275.3)
		$ (261.4)	$ (54.2)	$ (7.1)	$ 2.8	$ (2.9)	$ —	$(322.8)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $13.7 million of gains at December 31, 2012.

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, 2012						At December 31, 2011	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	2,628,011	$ 3.39	$ 3.43	$ 0.2	$ (0.3)	$ —	$ (0.1)
	NGL	120,000	$ 85.24	$ 73.16	$ 1.4	$ —	$ —	$ —
	Crude Oil	30,000	$ 92.42	$ 86.97	$ 0.2	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	5,487,300	$ 4.84	$ 3.43	$ 7.8	$ —	$ 5.9	$ —
	NGL	2,728,135	$ 55.46	$ 55.67	$ 9.3	$ (9.9)	$ 0.5	$ (8.7)
	Crude Oil	1,732,935	$ 91.75	$ 93.20	$ 6.3	$ (8.8)	$ 3.7	$ (10.0)
Receive variable/pay variable	Natural Gas	48,477,500	$ 3.45	$ 3.43	$ 1.2	$ (0.2)	$ 0.8	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,009,246	$ 33.13	$ 33.34	$ 0.6	$ (0.8)	$ —	$ —
	Crude Oil	173,774	$ 91.95	$ 92.23	$ 0.4	$ (0.4)	$ —	$ —
Receive fixed/pay variable	NGL	2,132,141	$ 26.96	$ 26.76	$ 2.6	$ (2.2)	$ —	$ —
	Crude Oil	284,774	$ 89.55	$ 92.29	$ 0.2	$ (1.0)	$ —	$ —
Receive variable/pay variable	Natural Gas	26,152,942	$ 3.48	$ 3.45	$ 0.9	$ —	$ 0.5	$ —
	NGL	6,399,658	$ 32.49	$ 32.03	$ 5.2	$ (2.3)	$ 0.4	$ (0.1)
	Crude Oil	1,106,574	$ 95.12	$ 92.04	$ 6.4	$ (3.0)	$ —	$ —
Pay fixed	Power(4)	42,924	$ 32.25	$ 42.82	$ —	$ (0.5)	$ —	$ (0.3)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 3.95	$ 5.22	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	2,346,900	$ 4.02	$ 3.95	$ 0.2	$ —	$ —	$ —
	NGL	801,175	$ 63.75	$ 66.00	$ 0.9	$ (2.7)	$ 0.8	$ (1.9)
	Crude Oil	1,301,955	$ 94.21	$ 92.16	$ 5.4	$ (2.7)	$ 4.9	$ (3.1)
Receive variable/pay variable	Natural Gas	7,212,500	$ 3.99	$ 3.98	$ 0.1	$ (0.1)	$ 0.1	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	10,556,275	$ 4.02	$ 3.97	$ 0.5	$ —	$ 0.1	$ —
	NGL	3,600,000	$ 12.40	$ 12.40	$ —	$ —	$ —	$ —
Pay fixed	Power(4)	58,608	$ 33.10	$ 46.58	$ —	$ (0.8)	$ —	$ (0.5)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$ 84.31	$ 0.7	$ (0.2)	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 90.01	$ 6.8	$ (0.2)	$ 6.0	$ (0.4)
Physical Contracts								
Receive variable/pay variable	Natural Gas	7,838,425	$ 4.28	$ 4.23	$ 0.4	$ —	$ 0.1	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 88.10	$ 0.5	$ —	$ 0.4	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	783,240	$ 4.53	$ 4.42	$ 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, 2012 and 2011, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.4 million of losses and $0.8 million of losses at December 31, 2012 and 2011, 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, 2012 and 2011.

	At December 31, 2012						At December 31, 2011	
					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 2013								
Puts (purchased)	Natural Gas	1,642,500	$ 4.18	$ 3.41	$ 1.4	$ —	$ 1.2	$ —
	NGL	457,000	$32.29	$ 27.87	$ 3.7	$ —	$ 0.9	$ —
Portion of option contracts maturing in 2014								
Puts (purchased)	NGL	127,750	$66.39	$ 70.78	$ 1.3	$ —	$ —	$ —

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

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

(3) The fair value is determined based on quoted market prices at December 31, 2012 and 2011, 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 losses at December 31, 2011.

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 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 hedge, or is not designated as a 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," 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 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 and interest rate 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.

- **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. In the second quarter 2009, we determined that a sub-group of physical NGL sales contracts with terms allowing for economic net settlement did 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. The forward contracts for which we have revoked the NPNS election do not qualify for hedge accounting 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. Historically, we have not considered these contracts to be derivatives under the NPNS exception allowed by authoritative accounting guidance. In the first quarter of 2010, we determined that a sub-group of physical natural gas sales contracts with terms allowing for economic net settlement did 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 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.

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:

- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- 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 net unrealized gains and losses associated with the changes in fair value of our derivative financial instruments:

	December 31,		
	2012	2011	2010
	(in millions)		
Liquids segment			
Non-qualified hedges	$ 1.3	$ 14.4	$ (2.8)
Natural Gas segment			
Hedge ineffectiveness	3.1	(5.3)	3.5
Non-qualified hedges	1.2	21.1	0.9
Marketing			
Non-qualified hedges	(3.1)	0.7	(6.7)
Commodity derivative fair value net gains (losses)	2.5	30.9	(5.1)
Corporate			
Hedge ineffectiveness	(20.5)	(0.3)	—
Non-qualified interest rate hedges	(0.5)	(0.5)	(1.0)
Derivative fair value net gains (losses)	$ (18.5)	$ 30.1	$ (6.1)

Derivative Positions

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

	December 31,	
	2012	2011
	(in millions)	
Other current assets	$ 28.3	$ 20.2
Other assets, net	15.8	13.0
Accounts payable and other	(256.7)	(166.2)
Other long-term liabilities	(68.3)	(121.5)
	$ (280.9)	$ (254.5)

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 long-term 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 $42.8 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, 2012 and 2011, unrealized commodity hedge losses of $6.3 million and $6.9 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $248.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2012, will be reclassified from AOCI to earnings during the next 12 months.

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.

In connection with our March 2010 issuance and sale of $500 million in principal amount of our 5.20% senior notes due March 15, 2020, which we refer to as the 2020 Notes, we paid $13.2 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the 2020 Notes. We also received $10.2 million to settle treasury locks associated with our September 2010 issuance and sale of $400 million in principal amount of our 5.50% senior notes due September 15, 2040, which we refer to as the 2040 Notes, that we entered to hedge the interest payments on a portion of the obligations through the maturity date of the 2040 Notes. Both the $13.2 million and $10.2 million settlement amounts are being amortized from AOCI to "Interest expense" over the respective 10- and 30-year terms of the 2020 and 2040 Notes.

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

	December 31,	
	2012	2011
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ (0.2)
AA	(116.5)	(98.4)
A	(147.7)	(160.7)
Lower than A	(16.7)	4.8
	$ (280.9)	$ (254.5)

* As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. 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 would include any cash collateral received in the balances listed above, however, as of December 31, 2012 and 2011, we are holding no 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, 2012 we would have been required to provide additional letters of credit in the amount of $45.4 million.

At December 31, 2012 and 2011, we had credit concentrations in the following industry sectors, as presented below:

	December 31, 2012	December 31, 2011
	(in millions)	
United States financial institutions and investment banking entities	$ (204.5)	$ (163.6)
Non-United States financial institutions	(84.6)	(88.7)
Other	8.2	(2.2)
	$ (280.9)	$ (254.5)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $231.2 million and $173.2 million relating to our liability exposures pursuant to the margin thresholds in effect at December 31, 2012 and 2011, 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 decrease the fair value of the positions.

Quantitative Information About Level 3 Fair Value Measurements

Contract Type	Fair Value at December 31, 2012[2]	Valuation Technique	Unobservable Input	Range[1] Lowest	Range[1] Highest	Range[1] Weighted Average	Units
	(in millions)						
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	—	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.

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.

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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* 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 14, 2013

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the year ended December 31,		
	2012	2011	2010
	(in millions, except per unit amounts)		
Operating revenue (Notes 12 and 15)	$6,706.1	$9,109.8	$7,736.1
Operating expenses:			
Cost of natural gas (Notes 6, 12 and 15)	4,570.1	7,100.1	5,963.3
Environmental costs, net of recoveries (Note 13)	(91.3)	(113.3)	600.8
Oil measurement adjustments (Notes 2 and 17)	(11.5)	(63.4)	5.6
Operating and administrative (Notes 2, 12 and 13)	852.0	705.0	576.5
Power (Note 15)	148.8	144.8	141.1
Depreciation and amortization (Note 7)	344.8	339.8	311.2
Impairment charge	—	—	10.3
	5,812.9	8,113.0	7,608.8
Operating income	893.2	996.8	127.3
Interest expense (Notes 10 and 15)	345.0	320.6	274.8
Other income (Notes 13 and 19)	10.0	6.5	17.5
Income (loss) before income tax expense	558.2	682.7	(130.0)
Income tax expense (Note 16)	8.1	5.5	7.9
Net income (loss)	550.1	677.2	(137.9)
Less: Net income attributable to noncontrolling interest (Note 12)	57.0	53.2	60.6
Net income (loss) attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 493.1	$ 624.0	$ (198.5)
Net income (loss) allocable to limited partner interest	$ 369.2	$ 520.5	$ (260.1)
Net income (loss) per limited partner unit (basic and diluted) (Note 4)	$ 1.27	$ 1.99	$ (1.09)
Weighted average limited partner units outstanding	290.6	262.3	239.1
Cash distributions paid per limited partner unit outstanding	$ 2.1520	$ 2.0925	$ 2.0240

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the year ended December 31,		
	2012	2011	2010
		(in millions)	
Net income (loss)	$ 550.1	$ 677.2	$ (137.9)
Other comprehensive income (loss), net of tax expense (benefit) of $0.2, $0.3, and $(0.1), respectively (Note 15)	(4.0)	(194.8)	(47.1)
Comprehensive income (loss)	546.1	482.4	(185.0)
Less: Comprehensive income attributable to noncontrolling interest (Note 12)	57.0	53.2	60.6
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 489.1	$ 429.2	$ (245.6)

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the year ended December 31,		
	2012	2011	2010
		(in millions)	
Cash provided by operating activities			
Net income (loss)	$ 550.1	$ 677.2	$ (137.9)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization (Note 7)	344.8	339.8	311.2
Derivative fair value net losses (gains) (Note 15)	18.5	(30.1)	6.1
Inventory market price adjustments (Note 6)	9.8	3.6	4.1
Environmental costs (Note 13)	72.6	171.2	600.8
Impairment charge (Notes 3)	—	—	10.3
Other (Note 21)	3.0	20.5	9.7
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	42.7	(2.6)	(20.0)
Due from General Partner and affiliates	(3.1)	3.8	(9.1)
Accrued receivables	(61.8)	174.6	(231.2)
Inventory (Note 6)	11.1	37.5	(68.0)
Current and long-term other assets (Note 15)	(7.3)	(7.7)	(2.0)
Due to General Partner and affiliates (Note 12)	(12.5)	4.9	3.9
Accounts payable and other (Notes 5 and 15)	(8.6)	46.4	55.3
Environmental liabilities (Note 13)	(100.3)	(292.3)	(337.1)
Accrued purchases	(19.1)	(101.6)	161.1
Interest payable	(0.9)	9.6	15.0
Property and other taxes payable	12.0	9.6	8.7
Settlement of interest rate derivatives (Note 15)	—	(18.8)	(3.0)
Net cash provided by operating activities	851.0	1,045.6	377.9
Cash used in investing activities			
Additions to property, plant and equipment (Note 7)	(1,826.2)	(1,096.6)	(716.2)
Changes in construction payables	86.3	51.4	12.6
Asset acquisitions	—	(46.6)	(713.3)
Proceeds from the sale of net assets	9.5	3.7	—
Joint venture contributions	(168.5)	—	—
Other	(7.7)	(10.9)	(10.9)
Net cash used in investing activities	(1,906.6)	(1,099.0)	(1,427.8)
Cash provided by financing activities			
Net proceeds from unit issuances (Note 11)	457.0	881.4	414.7
Distributions to partners (Note 11)	(660.3)	(565.7)	(481.6)
Repayments of long-term debt (Note 10)	(100.0)	(31.0)	(31.0)
Repayments to General Partner (Note 12)	(12.0)	(12.4)	(330.7)
Net proceeds from issuances of long-term debt (Note 10)	—	740.7	890.5
Net repayments under credit facility (Note 10)	—	—	(765.0)
Net commercial paper borrowings (repayments) (Note 10)	884.9	(609.8)	884.7
Borrowings from General Partner (Note 12)	—	7.0	408.4
Contribution from noncontrolling interest (Note 12)	350.9	3.3	102.3
Distributions to noncontrolling interest (Note 12)	(59.9)	(76.4)	(38.6)
Other	—	(5.7)	(2.5)
Net cash provided by financing activities	860.6	331.4	1,051.2
Net increase (decrease) in cash and cash equivalents	(195.0)	278.0	1.3
Cash and cash equivalents at beginning of year	422.9	144.9	143.6
Cash and cash equivalents at end of period	$ 227.9	$ 422.9	$ 144.9

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2012	December 31, 2011
	(in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 227.9	$ 422.9
Receivables, trade and other, net of allowance for doubtful accounts of $1.9 in 2012 and $1.5 in 2011 (Note 13)	142.4	235.3
Due from General Partner and affiliates	27.2	23.3
Accrued receivables	569.7	507.9
Inventory (Note 6)	72.7	93.6
Other current assets (Note 15)	48.0	36.4
	1,087.9	1,319.4
Property, plant and equipment, net (Notes 7, 12 and 19)	10,937.6	9,439.4
Goodwill (Note 8)	246.7	246.7
Intangibles, net (Note 9)	257.2	265.3
Other assets, net (Note 15)	267.4	99.3
	$ 12,796.8	$ 11,370.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 43.5	$ 55.0
Accounts payable and other (Notes 5, 15 and 19)	646.0	478.6
Environmental liabilities (Note 13)	108.0	172.1
Accrued purchases	484.1	503.2
Interest payable	69.0	69.9
Property and other taxes payable (Note 16)	71.4	59.4
Note payable to General Partner (Note 12)	12.0	12.0
Current maturities of long-term debt (Note 10)	200.0	100.0
	1,634.0	1,450.2
Long-term debt (Note 10)	5,501.7	4,816.1
Note payable to General Partner (Note 12)	318.0	330.0
Other long-term liabilities (Notes 13 and 15)	95.2	161.7
	7,548.9	6,758.0
Commitments and contingencies (Note 13)		
Partners' capital (Notes 11 and 12)		
Class A common units (254,208,428 and 238,043,964 at December 31, 2012 and December 31, 2011, respectively)	3,590.2	3,386.7
Class B common units (7,825,500 at December 31, 2012 and December 31, 2011)	83.9	82.2
i-units (41,198,424 and 38,566,334 at December 31, 2012 and December 31, 2011, respectively)	801.8	728.6
General Partner	299.0	285.6
Accumulated other comprehensive income (loss) (Note 15)	(320.5)	(316.5)
Total Enbridge Energy Partners, L.P. partners' capital	4,454.4	4,166.6
Noncontrolling interest (Note 12)	793.5	445.5
Total partners' capital	5,247.9	4,612.1
	$ 12,796.8	$ 11,370.1

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	For the year ended December 31,					
	2012		2011		2010	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
Class A common units:						
Beginning balance	238,043,964	$3,386.7	209,084,106	$2,641.0	194,886,704	$2,884.9
Net income (loss) allocation	—	306.2	—	430.5	—	(215.4)
Allocation of proceeds and issuance costs from unit issuances	16,164,464	418.5	28,959,858	769.5	14,197,402	367.5
Distributions	—	(521.2)	—	(454.3)	—	(396.0)
Ending balance	254,208,428	3,590.2	238,043,964	3,386.7	209,084,106	2,641.0
Class B common units:						
Beginning balance	7,825,500	82.2	7,825,500	64.9	7,825,500	78.6
Net income (loss) allocation	—	10.1	—	15.6	—	(8.0)
Allocation of proceeds and issuance costs from unit issuances	—	8.4	—	18.1	—	10.1
Distributions	—	(16.8)	—	(16.4)	—	(15.8)
Ending balance	7,825,500	83.9	7,825,500	82.2	7,825,500	64.9
i-units:						
Beginning balance	38,566,334	728.6	35,285,422	579.1	32,777,734	588.8
Net income (loss) allocation	—	50.5	—	72.3	—	(38.2)
Allocation of proceeds and issuance costs from unit issuances	—	22.7	860,684	77.2	—	28.5
Distributions	2,632,090	—	2,420,228	—	2,507,688	—
Ending balance	41,198,424	801.8	38,566,334	728.6	35,285,422	579.1
General Partner:						
Beginning balance		285.6		256.8		251.1
Net income allocation		126.3		105.6		63.1
General Partner contribution		9.4		18.2		12.4
Distributions		(122.3)		(95.0)		(69.8)
Ending balance		299.0		285.6		256.8
Accumulated other comprehensive income:						
Beginning balance		(316.5)		(121.7)		(74.6)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings		28.8		86.8		28.6
Unrealized net loss on derivative financial instruments		(32.8)		(281.6)		(75.7)
Ending balance		(320.5)		(316.5)		(121.7)
Total Enbridge Energy Partners, L.P. partners' capital at December 31,		4,454.4		4,166.6		3,420.1
Noncontrolling interest:						
Beginning balance		445.5		465.4		341.1
Capital contributions		350.9		3.3		102.3
Comprehensive income:						
Net income allocation		57.0		53.2		60.6
Distributions		(59.9)		(76.4)		(38.6)
Ending balance		793.5		445.5		465.4
Total partners' capital at December 31,		$5,247.9		$4,612.1		$3,885.5

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, along with natural gas gathering, treating, processing, transmission 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, 2012 and 2011, our ownership interests were distributed as follows:

	2012	2011
Class A common units owned by the public	67.1%	66.0%
Class A common units owned by our General Partner	15.1%	16.0%
Class B common units owned by our General Partner	2.5%	2.7%
i-units owned by Enbridge Management [(1)]	13.3%	13.3%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

(1) For each of the years ended December 31, 2012 and 2011, our General Partner owned 16.8% 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. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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.

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. We also have an option, exercisable prior to June 30, 2013, for the Partnership to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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. All other operations are captured by the LH interests.

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.

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, 2012 and 2011, Enbridge and its consolidated subsidiaries held an effective 21.8% and 23.0% 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 240 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 730 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 20.5 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 gathering and transmission pipelines, treating and processing plants and related facilities, predominantly located in active producing basins in east and north Texas, as well as the Texas Panhandle and western Oklahoma. At December 31, 2012, our Natural Gas segment, including the Elk City Natural Gas Gathering and Processing system, referred to as the Elk City system, which we acquired in September 2010, is comprised of 8 natural gas treating plants and 25 natural gas processing plants, excluding plants that are inactive and including plants we temporarily idle from time to time based on current volumes. In addition, our Natural Gas segment includes approximately 11,400 miles of natural gas gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting natural gas liquids, or NGLs, crude oil and carbon dioxide. For a discussion of our Elk City system, see Note 3. *Acquisitions and Dispositions*.

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 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.

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 derive revenue in our Natural Gas segment from the following types of arrangements:

Fee-Based and Take-or-Pay Arrangements

Under a fee-based contract, we receive a set fee for gathering, treating, processing and transporting raw natural gas and providing other similar services. These revenues correspond with the volumes and types of services we provide and do not depend directly on commodity prices. Revenues of our Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission 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 transmission volumes. Reservation fees are required to be paid whether or not the shipper delivers the volume, thus referred to as a take-or-pay arrangement. Additional revenues from our intrastate pipelines are derived from the combined sales of natural gas and transmission services.

Other Arrangements

We also use other types of arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales of natural gas, NGLs, and condensate, and by 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 other types of arrangements we use to derive revenues for our Natural Gas business 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 then sell at market prices and retain as our fee.

- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGLs and we generally contractually provide the customer their share of NGLs regardless of actual NGL production. This type of contract may also require the processor to provide a guaranteed NGL recovery percentage to the customer.

- Percentage-of-Index Contracts—Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.

- Keep-Whole Contracts—Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw natural gas at the wellhead, we also sell for our own account at market prices, the resulting residue gas. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue natural gas with an energy content equivalent to the original raw natural gas we received as measured in British thermal units, or Btu.

Under the terms of each of these contract structures, we retain a portion of the natural gas and NGLs as our fee in exchange for providing these producers with our services. In order to protect our unitholders from volatility in our cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to effectively fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time.

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 must 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, 2012, 2011 and 2010. 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 began including a portion of our capital expenditures for well-connects associated with our natural gas system assets as core maintenance expenditures beginning in 2009.

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, capitalized are certain costs 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 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. 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 debt and 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. Effective January 1, 2012, the State of Michigan repealed its former partnership tax laws and replaced them with a corporate income tax law, which the Partnership is not subject to.

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 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"
- 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 of 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.

Derivative financial instruments qualifying for hedge accounting treatment that we use are cash flow hedges. 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. 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, for derivative financial instruments that do not qualify for hedge accounting. 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 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 recorded an ARO of $0.4 million 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. We recorded an additional ARO of $0.4 million for the year ended 2010, when we removed from service the West Tulsa pipeline on our Mid-Continent system. For the year ended December 31, 2011, no additional AROs were recorded. We recorded accretion expense of $0.1 million, $0.1 million and $0.5 million, respectively, in our consolidated statements of income for the years ended December 31, 2012, 2011 and 2010 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, 2012 and 2011. 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, 2012 and 2011:

	2012	2011
	(in millions)	
Balance at beginning of period	$ 2.9	$ 2.8
Additions	0.4	—
Accretion expense	0.1	0.1
Balance at end of period	$ 3.4	$ 2.9

3. ACQUISITIONS AND DISPOSITIONS

The acquisitions and dispositions presented below include only transactions with unrelated third-parties. We also executed transactions with related parties, which we discuss in Note 12. *Related Party Transactions*. 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.

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.

2010 Acquisitions

Elk City System Acquisition

On September 16, 2010, we acquired 100% ownership of the entities that comprise the Elk City system for $686.1 million in cash, including amounts for working capital. The Elk City system extends from southwestern Oklahoma to Hemphill County in the Texas Panhandle. The Elk City system consists of approximately 800 miles of natural gas gathering and transportation pipelines, one carbon dioxide treating plant and three cryogenic processing plants with a total capacity of 370 million cubic feet per day, or MMcf/d, and a combined current natural gas liquid production capability of 20,000 Bpd. The acquisition of the Elk City system complements our existing Anadarko natural gas system by providing additional processing capacity and expansion capability. We used the net proceeds from the $400.0 million September 2010 issuance and sale of our 5.50% senior notes due September 15, 2040 to pay for a portion of the acquisition and funded the remaining amount with short-term borrowings of commercial paper, which we subsequently repaid with proceeds from our November 2010 equity issuance. The results of operations of the Elk City system have been included in our consolidated financial statements within our Natural Gas segment from the September 16, 2010 acquisition date. The Elk City system acquisition did not significantly impact the operating results of our Natural Gas business for the year ended December 31, 2010.

Other 2010 Acquisitions

In June 2010, we acquired natural gas pipeline assets for $16.9 million in cash that are complementary to our existing East Texas system assets and expansion into the South Haynesville area. In October 2010, we acquired a common carrier trucking company for $10.3 million in cash that expanded our existing trucking fleet in order to accommodate the growing supply needs of our United States Gulf Coast customers. Both acquisitions were allocated to "Property, plant and equipment, net" and "Intangibles, net" in our consolidated statement of financial position at fair value.

4. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

We allocate our net income among our General Partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, including any incentive distribution rights, or IDRs, 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 based on their sharing of losses of 2% and 98%, respectively, as set forth in our partnership agreement.

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,		
	2012	2011	2010
	(in millions, except per unit amounts)		
Net income (loss)	$ 550.1	$ 677.2	$ (137.9)
Less: Net income attributable to noncontrolling interest	57.0	53.2	60.6
Net income (loss) attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	493.1	624.0	(198.5)
Less distributions paid:			
Incentive distributions to our General Partner	(116.3)	(92.9)	(66.9)
Distributed earnings allocated to our General Partner	(13.0)	(11.6)	(10.1)
Total distributed earnings to our General Partner	(129.3)	(104.5)	(77.0)
Total distributed earnings to our limited partners	(636.3)	(568.3)	(493.1)
Total distributed earnings	(765.6)	(672.8)	(570.1)
Overdistributed earnings	$ (272.5)	$ (48.8)	$ (768.6)
Weighted average limited partner units outstanding	290.6	262.3	239.1
Basic and diluted earnings per unit:			
Distributed earnings per limited partner unit[1]	$ 2.19	$ 2.17	$ 2.06
Overdistributed earnings per limited partner unit[2]	(0.92)	(0.18)	(3.15)
Net income (loss) per limited partner unit (basic and diluted)	$ 1.27	$ 1.99	$ (1.09)

(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.

5. CASH AND CASH EQUIVALENTS

Obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $22.8 million at December 31, 2012 and $30.8 million at December 31, 2011 are included in "Accounts payable and other" on our consolidated statements of financial position.

6. INVENTORY

Our inventory is comprised of the following:

	December 31,	
	2012	2011
	(in millions)	
Materials and supplies	$ 1.9	$ 2.2
Crude oil inventory	12.7	10.7
Natural gas and NGL inventory	58.1	80.7
	$72.7	$93.6

The “Cost of natural gas” on our consolidated statements of income includes charges totaling $9.8 million, $3.6 million and $4.1 million for the years ended December 31, 2012, 2011 and 2010, 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, 2012	December 31, 2011[(1)]
		(in millions)	
Land	—	$ 40.4	$ 37.1
Rights-of-way	2.08% - 6.41%	604.5	564.4
Pipelines	.29% - 6.7%	6,662.3	6,268.1
Pumping equipment, buildings and tanks	1.48% - 11.11%	1,646.4	1,436.3
Compressors, meters and other operating equipment	1.8% - 20.0%	1,755.7	1,623.2
Vehicles, office furniture and equipment	1.4% - 33.3%	222.7	211.8
Processing and treating plants	2.21% - 4.00%	489.8	456.6
Construction in progress		1,867.2	874.3
Total property, plant and equipment		13,289.0	11,471.8
Accumulated depreciation		(2,351.4)	(2,032.4)
Property, plant and equipment, net		$10,937.6	$ 9,439.4

(1) For comparability purposes, we have made reclassifications of approximately $63.6 million out of the Processing and treating plants category and into the Land, Pumping equipment, buildings and tanks, and Compressors, meters and other operating equipment categories for the December 31, 2011 balances.

Based on our own internal study, with consideration of a third-party consultant’s report, revised depreciation rates for our Anadarko, North Texas and East Texas natural gas systems 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 will result in an approximately $34.0 million annual reduction in depreciation expense, with a reduction of $34.0 million and $17.0 million for the years ended December 31, 2012 and 2011, respectively.

8. GOODWILL

For each of the years ended December 31, 2012 and 2011, 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, 2012, 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, 2012 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, 2012, 2011 and 2010. 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, 2012.

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	Other	Intangible Assets, Gross	Natural Gas Intangibles	Other	Accumulated Amortization Gross	Intangible Assets, Net
				(in millions)			
December 31, 2010	$ 291.0	$ 16.1	$ 307.1	$ (28.5)	$ (2.2)	$ (30.7)	$ 276.4
Additions	—	0.2	0.2	—	—	—	0.2
Amortization	—	—	—	(10.8)	(0.5)	(11.3)	(11.3)
December 31, 2011	291.0	16.3	307.3	(39.3)	(2.7)	(42.0)	265.3
Additions	—	3.5	3.5	—	—	—	3.5
Amortization	—	—	—	(10.8)	(0.8)	(11.6)	(11.6)
December 31, 2012	$ 291.0	$ 19.8	$ 310.8	$ (50.1)	$ (3.5)	$ (53.6)	$ 257.2

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 approximate 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 approximate 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 $11.5 million per year until December 31, 2017.

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 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,			
		2012		2011	
	Maturity	Rate	Dollars	Rate	Dollars
			(in millions)		
Commercial Paper[1]	2017	0.46%	$1,160.0	0.44%	$ 275.0
Senior Notes	2013-2040	6.19%	4,142.1	6.23%	4,241.5
Junior Subordinated Notes	2067	8.05%	399.6	8.05%	399.6
			5,701.7		4,916.1
Current maturities and short-term debt			(200.0)		(100.0)
Long-term debt			$5,501.7		$4,816.1

(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

On July 6, 2012, we entered into a credit agreement with JPMorgan Chase Bank, as administrative agent, and a syndicate of 12 lenders, which we refer to as 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 $675.0 million 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. We refer to the 364-Day Credit Facility and the Credit Facility as our Credit Facilities. At December 31, 2012, we were in compliance with the terms of our financial covenants.

In September 2011, we entered into a credit agreement with Bank of America as administrative agent, and the lenders party thereto, which we refer to as the Credit Facility. The agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $2.0 billion, a letter of credit subfacility and a swing line subfacility. Effective September 26, 2012, we extended the maturity date to September 26, 2017 and amended it to adjust the base interest rates.

The Credit Facility replaces the previously existing credit facilities of $1,167.5 million and $600.0 million with Bank of America and Royal Bank of Canada, respectively.

On February 8, 2013, we amended the $675 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $1.1 billion. We use the unsecured revolving credit agreement to fund our general activities and working capital needs. The amended $1.1 billion credit agreement has terms consistent with our 364-Day Credit Facility. After this amendment, our Credit Facilities provide an aggregate amount of $3.1 billion of bank credit.

Effective September 30, 2011, our Credit Facility was amended to modify the definition of Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, as set forth in the terms of our Credit Facility, to increase from $550.0 million to $650.0 million, the aggregate amount of the costs associated with the crude oil releases on Lines 6A and 6B that are excluded from the computation of

Consolidated EBITDA. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue.

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, 2012, we could borrow $1,283.2 million under the terms of our Credit Facilities, determined as follows:

	(in millions)
Total credit available under Credit Facilities	$2,675.0
Less: Amounts outstanding under Credit Facilities	—
Principal amount of commercial paper outstanding	1,160.0
Letters of credit outstanding	231.8
Total amount we could borrow at December 31, 2012	$1,283.2

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, 2010, we have renewed LIBOR rate borrowings of $1,284.0 million, on a non-cash basis.

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 that is supported by our Credit Facilities. Our commercial paper program was increased from $1.0 billion in August 2011. 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, 2012, we had $1.2 billion in principal amount of commercial paper outstanding at a weighted average interest rate of 0.46%, excluding the effect of our interest rate hedging activities. At December 31, 2011, we had $275.0 million in principal amount of commercial paper outstanding at a weighted average interest rate of 0.44%, excluding the effect of our interest rate hedging activities. Our policy is to limit the commercial paper we can issue by the amounts available for us to borrow under our Credit Facilities.

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 outstanding senior notes pay interest semi-annually and have varying maturities and terms as presented in the table below. The senior notes do not contain any covenants restricting the issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. The holders of our $500.0 million in aggregate principal amount, 9.875% senior notes due 2019 did not notify us by the established 45-day notification date of their intent to exercise an option that would have required us to repurchase all or a portion of the notes on March 1, 2012 at a purchase price of 100% of the principal amount of the notes tendered plus accrued and unpaid interest.

During 2012, $100.0 million of our Notes reached full maturity, which we repaid in full on November 21, 2012.

In September 2011, we issued and sold $600.0 million in aggregate principal amount of senior notes due 2021, which we refer to as the 2021 Notes. The 2021 Notes bear interest at the rate of 4.20% per year and will mature on September 15, 2021. Interest on the 2021 Notes is payable on March 15 and September 15 of each year, beginning on March 15, 2012. Also in September 2011, we issued and sold an additional $150 million in aggregate principal amount of our 5.50% notes due in 2040, which we refer to as the 2040 Notes. The additional 2040 Notes will be fully fungible with, rank equally in right of payment with and form a part of the same series as the existing 2040 Notes, originally issued by us in September 2010, for all purposes under the governing indenture. We received net proceeds from the notes offerings in September 2011 of approximately $740.7 million after payment of underwriting discounts and commissions and offering expenses. We used the net proceeds from these offerings to repay a portion of our outstanding commercial paper, to fund a portion of our capital expansion projects and for general corporate purposes.

	Interest Rate	December 31, 2012	December 31, 2011
		(in millions)	
Senior Notes due 2012	7.900%	$ —	$ 100.0
Senior Notes due 2013	4.750%	200.0	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
		4,150.0	4,250.0
Unamortized discount		(7.9)	(8.5)
Total		$4,142.1	$4,241.5

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.

First Mortgage Notes

The First Mortgage Notes, or the Notes, were collateralized by a first mortgage lien on substantially all of the property, plant and equipment of the OLP, and were due and payable in equal annual installments of $31.0 million until their maturity. The Notes reached maturity and were repaid in full on December 15, 2011, at which time the related liens were released.

Interest

For the years ended December 31, 2012, 2011 and 2010 our interest cost is comprised of the following:

	For the year ended December 31,		
	2012	2011	2010
		(in millions)	
Interest expense	$ 345.0	$ 320.6	$ 274.8
Interest capitalized	36.3	13.6	8.7
Interest cost incurred	$ 381.3	$ 334.2	$ 283.5
Interest paid	$ 352.1	$ 314.3	$ 257.6

Maturities of Third Party Debt

The scheduled maturities of outstanding third-party debt, excluding any discounts at December 31, 2012, are summarized as follows in millions:

2013	200.0
2014	200.0
2015	—
2016	300.0
2017	1,160.0
Thereafter	3,850.0
Total	$5,710.0

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, 2012 and 2011, respectively, due to the frequent repricing of these obligations. The fair value of our outstanding commercial paper, borrowings under our Credit Facilities and our prior credit facilities and our Senior Notes due 2019 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.

	December 31,			
	2012		2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$1,160.0	$1,160.0	$ 275.0	$ 275.0
7.900% Senior Notes due 2012	—	—	100.0	106.1
4.750% Senior Notes due 2013	200.0	203.9	199.9	209.6
5.350% Senior Notes due 2014	200.0	215.6	200.0	218.9
5.875% Senior Notes due 2016	299.9	345.1	299.9	346.2
7.000% Senior Notes due 2018	99.9	124.6	99.9	123.8
6.500% Senior Notes due 2018	398.8	484.1	398.7	481.5
9.875% Senior Notes due 2019	500.0	710.5	500.0	715.1
5.200% Senior Notes due 2020	499.9	575.4	499.8	563.0
4.200% Senior Notes due 2021	598.9	644.2	598.8	620.8
7.125% Senior Notes due 2028	99.8	137.5	99.8	134.6
5.950% Senior Notes due 2033	199.8	244.2	199.7	238.1
6.300% Senior Notes due 2034	99.8	126.5	99.8	123.5
7.500% Senior Notes due 2038	399.0	573.8	399.0	563.5
5.500% Senior Notes due 2040	546.3	605.5	546.2	594.7
8.050% Junior subordinated notes due 2067	399.6	453.6	399.6	435.5
Total	$5,701.7	$6,604.5	$4,916.1	$5,749.9

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, 2012 include Class A common units, Class B common units and i-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, 2010, presented in our consolidated statements of income and the number of units presented in our consolidated statements of financial position are presented reflecting the retroactive effects of the share split.

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, 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 current year.

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
2010					
November[5][6]	11,960,000	$ 30.06	$ 347.4	$ 7.4	$ 354.8

(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.

(5) The proceeds from the November 2010 equity issuance were used to repay short term indebtedness incurred to finance the Elk City system acquisition and capital expansion projects.

(6) Amounts adjusted for the April 21, 2011 stock split.

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 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.

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 years ended December 31, 2011 and 2010 and there were no similar issuances in 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
2010					
April 1 to June 30[3]	574,690	$ 26.26	$ 14.8	$ 0.3	$ 15.1
July 1 to September 30[3]	1,373,482	$ 27.11	36.3	0.7	37.0
October 1 to December 31[3]	289,230	$ 27.85	7.6	0.2	7.8
2010 Totals[3]	2,237,402		$ 58.7	$ 1.2	$ 59.9

(1) Net of commissions and issuance costs of $2.2 million and $1.2 million for the years ended December 31, 2011 and 2010, respectively.

(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.

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 intend to use 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 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.

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.

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, 2012, 2011 and 2010.

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)			
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
2010[1]							
October 27	November 4	November 12	$ 0.51375	$ 143.0	$ 17.9	$ 0.3	$ 124.8
July 23	August 5	August 13	$ 0.51375	141.7	17.5	0.4	123.8
April 28	May 7	May 14	$ 0.50125	134.9	16.7	0.4	117.8
January 29	February 5	February 12	$ 0.49500	131.7	16.2	0.3	115.2
				$ 551.3	$ 68.3	$ 1.4	$ 481.6

(1) Distributions per unit for the distribution paid are presented retrospectively applying the two-for-one split of our units.

(2) We issued 2,632,090, i-units to Enbridge Management, L.L.C., the sole owner of our i-units, during 2012 in lieu of cash. We also issued 2,420,228 and 2,507,688 split adjusted i-units to Enbridge Management, during 2011 and 2010, respectively, in lieu of cash distributions.

(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.

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, 2012, 2011 and 2010 was $133.0 million, $97.3 million and $74.5 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, 2012, 2011 and 2010 was $291.1 million, $264.3 million and $231.6 million, respectively.

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of $33.1 million, $24.9 million and $16.3 million during 2012, 2011 and 2010, 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. 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.

Line 6A and 6B Expense Reimbursement

For the years ended December 31, 2012, 2011 and 2010, we have reimbursed Enbridge $4.1 million, $7.6 million and $14.9 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, 2012, 2011 and 2010, are operating revenues of $414.7 million, $354.3 million and $430.4 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 2012, 2011 and 2010 was approximately $0.8 million, $0.8 million and $0.9 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, 2012, 2011 and 2010, are costs for natural gas purchases of $285.4 million, $200.8 million and $242.3 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, 2012, 2011 and 2010 are as follows:

	A1 Term Note
	(in millions)
Balance at December 31, 2010	$ 347.4
Borrowings	7.0
Repayments	(12.4)
Balance at December 31, 2011	342.0
Borrowings	—
Repayments	(12.0)
Balance at December 31, 2012	$ 330.0

The following table presents in millions, the scheduled maturities of the A1 Term Note based upon the $330.0 million outstanding at December 31, 2012.

	(in millions)
2013	$ 12.0
2014	12.0
2015	12.0
2016	12.0
2017	12.0
Thereafter	270.0
Total	$ 330.0

Our General Partner also made equity contributions totaling $3.3 million and $102.3 to the OLP during the years ended 2011 and 2010, respectively, to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $53.9 million, $53.2 million and $60.6 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper Pipeline for the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010, 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)	
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
2010				
October 27	November 12	$ 10.7	$ 21.4	$ 32.1
July 23	August 13	8.6	17.2	25.8
		$ 19.3	$ 38.6	$ 57.9

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. 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 Eastern Access Joint Funding Agreement. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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 $347.9 million to the OLP for the year ended December 31, 2012, 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 $3.4 million to our General Partner for its 60% ownership of the EA interest for the year ended December 31, 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. 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. We also have an option, exercisable prior to June 30, 2013, for the Partnership to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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. All other operations are captured by the LH interests.

Our General Partner has made equity contributions totaling $3.0 million to the OLP for the year ended December 31, 2012, to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Asset Purchase and Sale Transactions with Affiliates

Line 13 Exchange and Lease

In connection with the development of a diluent pipeline being constructed by Enbridge Pipelines (Southern Lights), L.L.C., or Southern Lights, a wholly-owned subsidiary of our General Partner, we completed the transfer of a 156-mile section of pipeline, which we refer to as Line 13, from our Lakehead system to Southern Lights in exchange for a newly constructed pipeline for transporting light sour crude oil. In connection with the exchange, at the request of shippers and to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Pipeline, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease which became effective February 20, 2009, expired in April 2010 in accordance with the lease. For the year ended December 31, 2010, we paid $5.4 million to Southern Lights to lease Line 13, which we recovered through the tariff that went into effect on April 1, 2010 on our Lakehead system.

The exchange resulted in a $166.5 million increase in "Property, plant and equipment, net" and the capital account of our General Partner included in "Partners' capital" on our December 31, 2009 consolidated statement of financial position, representing the $171.5 million cost of the light sour pipeline that was in excess of the $5.0 million net book value of the Line 13 assets we exchanged. The costs were transferred to us through the capital account of our General Partner and are included in the $171.5 million. Further, $3.8 million of additional costs for the year ended December 31, 2010 were incurred and transferred by Southern Lights, which increased the total costs for the light sour crude oil pipeline at December 31, 2010 to $175.3 million. The light sour pipeline is newer and has a slightly higher capacity than Line 13, which will allow us to transport additional volumes of light sour crude oil on our Lakehead system with less integrity and maintenance costs, although depreciation and property tax expense is anticipated to increase in future periods due to the higher book value associated with these assets.

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 $122.3 million, $95.0 million and $69.8 million for the years ended December 31, 2012, 2011, and 2010, 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, 2012 and 2011, our General Partner owned 46,518,336 Class A common units, representing a 15.1% and 16.0% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $100.1 million, $97.3 million and $94.1 million for the years ended December 31, 2012, 2011 and 2010, respectively, with respect to its ownership of Class A common units. 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. The conversion became effective upon the determination by our General Partner that the converted Class C units would have, as a substantive matter, like intrinsic economic and United States federal income tax characteristics, in all material respects, to the intrinsic economic and United States federal income tax characteristics of our outstanding Class A common units. Along with the conversion and adjusted for the 2011 split, we issued and sold 42,490 Class A common units to our General Partner for a purchase price of $23.535 per unit, or approximately $1.0 million.

As of December 31, 2012 and 2011, our General Partner also owned 7,825,500 Class B common units, representing a 2.5% and 2.7% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $16.8 million, $16.4 million and $15.8 million for the years ended December 31, 2012, 2011, and 2010, respectively, with respect to its ownership of Class B common units.

As a result of the October 2009 conversion of all our outstanding Class C units into Class A common units, we did not have any Class C units outstanding at December 31, 2012 and 2011.

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 27[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
2010					
October 1 to December 31[1]	289,230	$ 27.85	$ 7.6	$ 0.2	$ 7.8
November	11,960,000	$ 30.06	$ 347.4	$ 7.4	$ 354.8
July 1 to September 30[1]	1,373,482	$ 27.11	$ 36.3	$ 0.7	$ 37.0
April 1 to June 30[1]	574,690	$ 26.26	$ 14.8	$ 0.3	$ 15.1

(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, 2012 and 2011, we had $18.3 million and $31.3 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.

During the second quarter 2012, local authorities allowed the Kalamazoo River and Morrow Lake, which were affected by the Line 6B crude oil release, to be re-opened for recreational use. We continue to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives we are undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, we received a Notice of Probable Violation, or NOPV, from the Pipeline and Hazardous Materials Safety Administration, or PHMSA, related to the Line 6B crude oil release, which resulted in a payment of $3.7 million civil penalty in the third quarter of 2012. We have included the amount of the penalty in our total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012, the National Transportation Safety Board, or NTSB, presented the results of its investigation into the Line 6B crude oil release and subsequently publicly posted its final report on July 26, 2012.

As of December 31, 2012, we have revised our total cost estimate to $820.0 million, primarily due to an estimate of extended oversight by regulators and additional legal costs associated with various lawsuits, which is an increase of $55.0 million from our estimate as of 2011. This total estimate is before insurance recoveries and excluding additional fines and penalties which may be imposed by federal, state and local governmental agencies, other than the PHMSA civil penalty described above. On October 3, 2012, we received a letter from the EPA regarding a proposed order, which we refer to as the Proposed Order, for potential incremental containment and active recovery of submerged oil. We are in discussions with the EPA regarding the agency’s intent with respect to certain elements of the Proposed Order and the appropriate scope of these activities. The nature and scope of any additional remediation activities that regulators may require is currently uncertain. Studies and additional technical evaluation by the EPA, the Partnership and other regulatory agencies may need to be completed before a final determination of any additional remediation activities can be determined. We have accrued the estimated costs we deem likely to be incurred. However, when a final determination of the appropriate nature and scope of an additional remediation is made, it could result in significant cost being accrued.

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, 2012. 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 PHMSA civil penalty described above. 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	$ 369
Environmental consultants	149
Professional, regulatory and other	302
Total	$ 820

For the years ended December 31, 2012, 2011 and 2010, we made payments of $134.0 million, $276.6 million and $293.6 million, respectively, for costs associated with the Line 6B crude oil release. For the years ended December 31, 2012 and 2011, we had a remaining estimated liability of $115.8 million and $194.8 million, respectively. Additionally, we recognized $170.0 million and $335.0 million, respectively, of insurance recoveries in our consolidated statements of income for the years ended December 31, 2012 and 2011.

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. The cause of the crude oil release remains subject to investigation by federal and state environmental and pipeline safety regulators.

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.

In connection with this crude oil release, the total cost estimate as of December 31, 2012 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, 2012, 2011 and 2010, we paid $1.2 million, $11.0 million and $34.4 million, respectively, related to the costs on the Line 6A release. For the years ended December 31, 2012 and 2011, we had a remaining estimated liability of $1.4 million and $2.6 million, respectively.

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, 2012, which may be imposed by the EPA and PHMSA, in addition to other federal, state and local governmental agencies. Our estimated costs at December 31, 2012 for the Line 6B crude oil release include $3.7 million in civil penalties assessed by PHMSA that we paid during the third quarter of 2012, but do not include any other fines or penalties which may be imposed by other governmental agencies. Several factors remain outstanding at the end of the period that we consider critical in estimating the amount of additional fines and penalties that we may be assessed.

Due to the absence of sufficient information, we cannot provide a reasonable estimate of our liability for potential additional fines and penalties that we could be assessed in connection with each of the releases. As a result, except for the PHMSA civil penalty, 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, which renews in May of each year. The insurance program 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. 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. 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, 2012, we have exceeded the limits of coverage under this insurance policy. 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.

For the years ended December 31, 2012 and 2011, we recognized $170.0 million and $335.0 million, respectively, of insurance recoveries as reductions to “Environmental costs, net of recoveries” in our consolidated statements of income. As of December 31, 2012, we have recorded total insurance recoveries of $505.0 million for the Line 6B crude oil release, and we expect to recover the balance of our aggregate liability insurance coverage of $145.0 million from our insurers in future periods. We will record receivables for additional amounts we receive through insurance recoveries during the period that we deem recovery to be probable.

Effective May 1, 2012, Enbridge renewed its comprehensive insurance program, through April 30, 2013, with a current liability aggregate limit of $660.0 million, including sudden and accidental pollution liability.

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 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 of pipeline are targeted to be placed in service during 2013 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. The pressure restrictions will remain in place until such time we can demonstrate that the root cause of the incident has been remediated.

We revised our disclosed estimate for repair and remediation related costs associated with this crude oil release as of December 31, 2012 to approximately $10.5 million, inclusive of approximately $1.6 million of 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.

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 27 million to 56 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 $2.7 million, $2.5 million and $2.2 million for the leased right-of-way agreements for the years ended December 31, 2012, 2011, and 2010, respectively.

Fines and Penalties

For the year ended December 31, 2012, our estimated costs to the Line 6B crude oil release included $3.7 million in civil penalties assessed by PHMSA that we paid during the third quarter of 2012, but do not include any other fines or penalties which may be imposed by other governmental agencies.

We paid $100,000 to PHMSA in October 2011 to resolve an administrative civil penalty brought against us by PHMSA for failure to follow our procedures for maintaining minimum clearance from underground facilities when excavating with powered equipment, related to one of our pipelines located in Rusk County, Wisconsin.

We paid $1.0 million to the State of Wisconsin in October 2010 to resolve fines, penalties and related matters associated with a proceeding brought against us by the State of Wisconsin Department of Justice on behalf of the Wisconsin Department of Natural Resources, for emissions and permit matters associated with our storage tanks located at the Superior, Wisconsin pipeline terminal.

In September of 2010, we paid a $2.4 million fine to settle proceedings brought against us by PHMSA for the unexpected release and fire on Line 3 of our Lakehead system that occurred in November 2007 during planned maintenance near our Clearbrook, Minnesota terminal.

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 have been filed 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.

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 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.

Future Minimum Commitments

As of December 31, 2012, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

	2013	2014	2015	2016	2017	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$720.5	$ —	$ —	$ —	$ —	$ —	$ 720.5
Power commitments[2]	4.1	0.5	—	—	—	—	4.6
Other operating leases	24.4	23.7	22.2	21.5	20.6	100.2	212.6
Right-of-way[3]	3.4	3.2	3.1	2.7	1.9	44.3	58.6
Product purchase obligations[4]	163.0	15.2	9.8	—	—	—	188.0
Transportation/Service contract obligations[5]	35.6	43.4	42.4	39.5	79.0	551.2	791.1
Fractionation agreement obligations[6]	36.1	43.3	43.3	43.3	43.3	219.7	429.0
Total	$987.1	$129.3	$120.8	$107.0	$144.8	$915.4	$2,404.4

(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 $1.9 million to $3.4 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 2017.

(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, 2012, 2011 and 2010 were $276.7 million, $232.0 million and $294.6 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).

	2010 DR(CR)	2011 DR(CR)
Balance Sheet		
Accrued Receivables	$ (9.1)	$ —
Total assets	$ (9.1)	$ —
Accrued Purchases	$ (23.8)	$ —
Total liabilities	(23.8)	—
Partners' Capital	32.9	—
Total liabilities and Partners' Capital	$ 9.1	$ —

	2010 DR(CR)	2011 DR(CR)
Income Statement		
Operating Revenue	$ 7.8	$ (9.1)
Cost of Natural Gas	(2.5)	(23.8)
Net income	$ 5.3	$ (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 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 2016 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 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 hedge, or is not designated as a 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,” 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 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 and interest rate 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.

- **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. In the second quarter 2009, we determined that a sub-group of physical NGL sales contracts with terms allowing for economic net settlement did 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. The forward contracts for which we have revoked the NPNS election do not qualify for hedge accounting 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. Historically, we have not considered these contracts to be derivatives under the NPNS exception allowed by authoritative accounting guidance. In the first quarter of 2010, we determined that a sub-group of physical natural gas sales contracts with terms allowing for economic net settlement did 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 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.

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:

- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- 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 net unrealized gains and losses associated with the changes in fair value of our derivative financial instruments:

	December 31,		
	2012	2011	2010
	(in millions)		
Liquids segment			
Non-qualified hedges	$ 1.3	$ 14.4	$ (2.8)
Natural Gas segment			
Hedge ineffectiveness	3.1	(5.3)	3.5
Non-qualified hedges	1.2	21.1	0.9
Marketing			
Non-qualified hedges	(3.1)	0.7	(6.7)
Commodity derivative fair value net gains (losses)	2.5	30.9	(5.1)
Corporate			
Hedge ineffectiveness	(20.5)	(0.3)	—
Non-qualified interest rate hedges	(0.5)	(0.5)	(1.0)
Derivative fair value net gains (losses)	$ (18.5)	$ 30.1	$ (6.1)

Derivative Positions

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

	December 31,	
	2012	2011
	(in millions)	
Other current assets	$ 28.3	$ 20.2
Other assets, net	15.8	13.0
Accounts payable and other	(256.7)	(166.2)
Other long-term liabilities	(68.3)	(121.5)
	$ (280.9)	$ (254.5)

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 long-term 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 $42.8 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, 2012 and 2011, unrealized commodity hedge losses of $6.3 million and $6.9 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $248.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2012, will be reclassified from AOCI to earnings during the next 12 months.

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.

In connection with our March 2010 issuance and sale of $500 million in principal amount of our 5.20% senior notes due March 15, 2020, which we refer to as the 2020 Notes, we paid $13.2 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the 2020 Notes. We also received $10.2 million to settle treasury locks associated with our September 2010 issuance and sale of $400 million in principal amount of our 5.50% senior notes due September 15, 2040, which we refer to as the 2040 Notes, that we entered to hedge the interest payments on a portion of the obligations through the maturity date of the 2040 Notes. Both the $13.2 million and $10.2 million settlement amounts are being amortized from AOCI to "Interest expense" over the respective 10- and 30-year terms of the 2020 and 2040 Notes.

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

	December 31,	
	2012	2011
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ (0.2)
AA	(116.5)	(98.4)
A	(147.7)	(160.7)
Lower than A	(16.7)	4.8
	$ (280.9)	$ (254.5)

* As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also decreased. 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 would include any cash collateral received in the balances listed above, however, as of December 31, 2012 and 2011, we are holding no 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, 2012 we would have been required to provide additional letters of credit in the amount of $45.4 million.

At December 31, 2012 and 2011, we had credit concentrations in the following industry sectors, as presented below:

	December 31,	
	2012	**2011**
	(in millions)	
United States financial institutions and investment banking entities	$ (204.5)	$ (163.6)
Non-United States financial institutions	(84.6)	(88.7)
Other	8.2	(2.2)
	$ (280.9)	$ (254.5)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $231.2 million and $173.2 million relating to our liability exposures pursuant to the margin thresholds in effect at December 31, 2012 and 2011, 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.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Asset Derivatives			Liability Derivatives		
	Financial Position Location	Fair Value at December 31, 2012	Fair Value at December 31, 2011	Financial Position Location	Fair Value at December 31, 2012	Fair Value at December 31, 2011
			(in millions)			
Derivatives designated as hedging instruments[1]						
Interest rate contracts	Other current assets	$ —	$ —	Accounts payable and other	$(246.9)	$(134.1)
Interest rate contracts	Other assets, net	6.0	0.2	Other long-term liabilities	(68.3)	(109.4)
Commodity contracts	Other current assets	16.8	6.4	Accounts payable and other	(9.9)	(30.5)
Commodity contracts	Other assets, net	4.5	11.4	Other long-term liabilities	(5.5)	(25.9)
		27.3	18.0		(330.6)	(299.9)
Derivatives not designated as hedging instruments						
Interest rate contracts	Other current assets	2.4	4.8	Accounts payable and other	(2.2)	(4.4)
Interest rate contracts	Other assets, net	—	2.5	Other long-term liabilities	—	(2.3)
Commodity contracts	Other current assets	28.8	31.7	Accounts payable and other	(17.5)	(19.9)
Commodity contracts	Other assets, net	13.3	16.4	Other long-term liabilities	(2.4)	(1.4)
		44.5	55.4		(22.1)	(28.0)
Total derivative instruments		$71.8	$73.4		$(352.7)	$(327.9)

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

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, 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)
For the year ended December 31, 2010					
Interest rate contracts	$ (52.9)	Interest expense	$ (7.2)	Interest expense	$ 0.2
Commodity contracts	7.4	Cost of natural gas	(21.4)	Cost of natural gas	3.5
Total	$ (45.5)		$ (28.6)		$ 3.7

(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.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	December 31, 2012	2011	2010
		Amount of Gain or (Loss) Recognized in Earnings[1]		
		(in millions)		
Interest rate contracts	Interest expense	$ (0.5)	$ (0.5)	$ (1.0)
Commodity contracts	Operating revenue	1.2	14.9	(2.0)
Commodity contracts	Power	0.1	(0.5)	(0.8)
Commodity contracts	Cost of natural gas	(1.9)	21.8	(5.8)
Total		$ (1.1)	$ 35.7	$ (9.6)

(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.

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	December 31, 2012			December 31, 2011		
	Assets	Liabilities	Total	Assets	Liabilities	Total
	(in millions)					
Fair value of derivatives—gross presentation	$ 71.8	$ (352.7)	$ (280.9)	$ 73.4	$ (327.9)	$ (254.5)
Effects of netting agreements	(27.7)	27.7	—	(40.2)	40.2	—
Fair value of derivatives—net presentation	$ 44.1	$ (325.0)	$ (280.9)	$ 33.2	$ (287.7)	$ (254.5)

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, 2012 and 2011. 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, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts	$ —	$ (309.0)	$ —	$ (309.0)	$ —	$ (242.6)	$ —	$ (242.6)
Commodity contracts:								
Financial	—	7.2	8.4	15.6	—	(10.2)	(15.9)	(26.1)
Physical	—	—	6.1	6.1	—	—	4.2	4.2
Commodity options	—	—	6.4	6.4	—	—	10.0	10.0
Total	$ —	$ (301.8)	$ 20.9	$ (280.9)	$ —	$ (252.8)	$ (1.7)	$ (254.5)

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 decrease the fair value of the positions.

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	Range[1] Highest	Range[1] Weighted Average	Range[1] 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	—	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.

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, 2012 to December 31, 2012. 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, 2012	$ (15.9)	$ 4.2	$ 10.0	$ (1.7)
Transfers in (out) of Level 3[1]	—	—	—	—
Gains or losses				
Included in earnings (or changes in net assets)	3.2	30.0	10.2	43.4
Included in other comprehensive income	37.5	—	(0.2)	37.3
Purchases, issuances, sales and settlements				
Purchases	—	—	3.4	3.4
Settlements[2]	(16.4)	(28.1)	(17.0)	(61.5)
Ending balance as of December 31, 2012	$ 8.4	$ 6.1	$ 6.4	$ 20.9
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$ 10.6	$ 6.0	$ 4.3	$ 20.9

(1) Our policy is to recognize transfers as of the last day of the reporting period.

(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair value of expected cash flows of our outstanding commodity based swaps and physical contracts at December 31, 2012 and 2011.

	At December 31, 2012						At December 31, 2011	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	2,628,011	$ 3.39	$ 3.43	$ 0.2	$ (0.3)	$ —	$ (0.1)
	NGL	120,000	$ 85.24	$ 73.16	$ 1.4	$ —	$ —	$ —
	Crude Oil	30,000	$ 92.42	$ 86.97	$ 0.2	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	5,487,300	$ 4.84	$ 3.43	$ 7.8	$ —	$ 5.9	$ —
	NGL	2,728,135	$ 55.46	$ 55.67	$ 9.3	$ (9.9)	$ 0.5	$ (8.7)
	Crude Oil	1,732,935	$ 91.75	$ 93.20	$ 6.3	$ (8.8)	$ 3.7	$ (10.0)
Receive variable/pay variable	Natural Gas	48,477,500	$ 3.45	$ 3.43	$ 1.2	$ (0.2)	$ 0.8	$ (0.1)
Physical Contracts								
Receive variable/pay fixed	NGL	1,009,246	$ 33.13	$ 33.34	$ 0.6	$ (0.8)	$ —	$ —
	Crude Oil	173,774	$ 91.95	$ 92.23	$ 0.4	$ (0.4)	$ —	$ —
Receive fixed/pay variable	NGL	2,132,141	$ 26.96	$ 26.76	$ 2.6	$ (2.2)	$ —	$ —
	Crude Oil	284,774	$ 89.55	$ 92.29	$ 0.2	$ (1.0)	$ —	$ —
Receive variable/pay variable	Natural Gas	26,152,942	$ 3.48	$ 3.45	$ 0.9	$ —	$ 0.5	$ —
	NGL	6,399,658	$ 32.49	$ 32.03	$ 5.2	$ (2.3)	$ 0.4	$ (0.1)
	Crude Oil	1,106,574	$ 95.12	$ 92.04	$ 6.4	$ (3.0)	$ —	$ —
Pay fixed	Power[4]	42,924	$ 32.25	$ 42.82	$ —	$ (0.5)	$ —	$ (0.3)
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 3.95	$ 5.22	$ —	$ —	$ —	$ —
Receive fixed/pay variable	Natural Gas	2,346,900	$ 4.02	$ 3.95	$ 0.2	$ —	$ —	$ —
	NGL	801,175	$ 63.75	$ 66.00	$ 0.9	$ (2.7)	$ 0.8	$ (1.9)
	Crude Oil	1,301,955	$ 94.21	$ 92.16	$ 5.4	$ (2.7)	$ 4.9	$ (3.1)
Receive variable/pay variable	Natural Gas	7,212,500	$ 3.99	$ 3.98	$ 0.1	$ (0.1)	$ 0.1	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	10,556,275	$ 4.02	$ 3.97	$ 0.5	$ —	$ 0.1	$ —
	NGL	3,600,000	$ 12.40	$ 12.40	$ —	$ —	$ —	$ —
Pay fixed	Power[4]	58,608	$ 33.10	$ 46.58	$ —	$ (0.8)	$ —	$ (0.5)
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	NGL	109,500	$ 88.36	$ 84.31	$ 0.7	$ (0.2)	$ 0.7	$ (0.2)
	Crude Oil	865,415	$ 97.72	$ 90.01	$ 6.8	$ (0.2)	$ 6.0	$ (0.4)
Physical Contracts								
Receive variable/pay variable	Natural Gas	7,838,425	$ 4.28	$ 4.23	$ 0.4	$ —	$ 0.1	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$ 99.31	$ 88.10	$ 0.5	$ —	$ 0.4	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	783,240	$ 4.53	$ 4.42	$ 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, 2012 and 2011, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.4 million of losses and $0.8 million of losses at December 31, 2012 and 2011, 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, 2012 and 2011.

	At December 31, 2012						At December 31, 2011	
					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 2013								
Puts (purchased)	Natural Gas	1,642,500	$ 4.18	$ 3.41	$1.4	$—	$1.2	$—
	NGL	457,000	$32.29	$27.87	$3.7	$—	$0.9	$—
Portion of option contracts maturing in 2014								
Puts (purchased)	NGL	127,750	$66.39	$70.78	$1.3	$—	$ —	$—

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

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

(3) The fair value is determined based on quoted market prices at December 31, 2012 and 2011, 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 losses at December 31, 2011.

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 December 31,	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	2012	2011
			(dollars in millions)		
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed . .	Cash Flow Hedge	$ 800	3.24%	$ (22.6)	$ (42.2)
Interest Rate Swaps—Pay Fixed . .	Non-qualifying	$ 125	4.35%	$ (2.2)	$ (6.8)
Interest Rate Swaps—Pay Float . .	Non-qualifying	$ 125	4.75%	$ 2.4	$ 7.5
Contracts maturing in 2014					
Interest Rate Swaps—Pay Fixed . .	Cash Flow Hedge	$ 200	0.56%	$ (0.6)	$ 0.2
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed . .	Cash Flow Hedge	$ 300	2.43%	$ (6.7)	$ (4.7)
Contracts maturing in 2017					
Interest Rate Swaps—Pay Fixed . .	Cash Flow Hedge	$ 500	2.21%	$ (16.0)	$ (5.8)
Contracts maturing in 2018					
Interest Rate Swaps—Pay Fixed . .	Cash Flow Hedge	$ 500	2.08%	$ (1.8)	$ —
Contracts settling prior to maturity					
2012—Pre-issuance Hedges	Cash Flow Hedge	$ 600	4.56%	$ (154.0)	$ (123.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$ 500	3.98%	$ (84.4)	$ (63.1)
2014—Pre-issuance Hedges	Cash Flow Hedge	$ 750	3.15%	$ (45.3)	$ (23.4)
2016—Pre-issuance Hedges	Cash Flow Hedge	$ 500	2.87%	$ 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, 2012 and 2011, 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 $13.7 million of gains at December 31, 2012 and $19.4 million of gains at December 31, 2011

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 $8.1 million, $5.5 million and $7.9 million for the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010. The Michigan state income tax rate was 0.2% for the years ended 2011 and 2010. Our income tax expense represents effective tax rates as applied to pretax book income of 1.6%, 0.9% and (4.1%) for December 31, 2012, 2011 and 2010, 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. The negative effective tax rate for 2010 results from pretax net book losses are coupled with positive income tax expense.

At December 31, 2012 and 2011, we have included a current income tax payable of $7.7 million and $7.2 million in "Property and other taxes payable," respectively. In addition, at December 31, 2012 and December 31, 2011, we have included a deferred income tax liability of $3.0 million and $2.8 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.

For the years ended December 31, 2012, 2011 and 2010, we paid $7.6 million, $7.4 million and $6.5 million in income taxes, respectively.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment. The tax effects of significant temporary differences representing deferred tax assets and liabilities are as follows:

	December 31,	
	2012	2011
	(in millions)	
Net book basis of assets in excess of tax basis	$ (3.0)	$ (3.0)
Net book losses on derivatives not recognized for tax purposes	—	0.2
Net deferred tax liability	$ (3.0)	$ (2.8)

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 January 1, 2012	$ —
Additions for tax positions taken in current period	21.8
Unrecognized tax benefits at December 31, 2012	$ 21.8

Additions for tax positions taken in the current period relate entirely to a state income tax refund claim filed in November 2012. As of December 31, 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 $5.1 million during the next twelve months. As of December 31, 2012, $0.5 million of accrued interest income has not been included in the balance of unrecognized tax benefits. The Company recognizes accrued interest income related to unrecognized tax benefits in interest income when the related unrecognized tax benefits are recognized.

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ended December 2011, 2010, and 2009.

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.

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, 2012				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
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
Other income	—	—	—	10.0	10.0
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.

	As of and for the year ended December 31, 2011				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
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.

	As of and for the year ended December 31, 2010				
	Liquids	Natural Gas	Marketing	Corporate[(1)]	Total
			(in millions)		
Total revenue	$ 1,173.6	$ 5,745.7	$ 2,379.1	$ —	$ 9,298.4
Less: Intersegment revenue	1.8	1,515.6	44.9	—	1,562.3
Operating revenue	1,171.8	4,230.1	2,334.2	—	7,736.1
Cost of natural gas	—	3,641.9	2,321.4	—	5,963.3
Environmental costs, net of recoveries	600.8	—	—	—	600.8
Oil measurement adjustments	5.6	—	—	—	5.6
Operating and administrative	259.9	303.6	8.9	4.1	576.5
Power	141.1	—	—	—	141.1
Depreciation and amortization	178.8	132.2	0.2	—	311.2
Impairment charge	10.3	—	—	—	10.3
	1,196.5	4,077.7	2,330.5	4.1	7,608.8
Operating income (loss)	(24.7)	152.4	3.7	(4.1)	127.3
Interest expense	—	—	—	274.8	274.8
Other income	—	—	—	17.5	17.5
Income (loss) before income tax expense	(24.7)	152.4	3.7	(261.4)	(130.0)
Income tax expense	—	—	—	7.9	7.9
Net income (loss)	(24.7)	152.4	3.7	(269.3)	(137.9)
Less: Net income attributable to the noncontrolling interest	—	—	—	60.6	60.6
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (24.7)	$ 152.4	$ 3.7	$ (329.9)	$ (198.5)
Total assets	$ 5,467.6	$ 4,494.1	$ 237.8	$ 241.5	$ 10,441.0
Capital expenditures (excluding acquisitions)	$ 427.7	$ 279.9	$ —	$ 8.6	$ 716.2

(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.

19. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative accounting provisions applicable to the regulated operations of our Southern Access and Alberta Clipper pipelines. The rates for both the Southern Access and Alberta Clipper pipelines 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 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, 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 December 31, 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 December 31, 2012. The amounts will be included in our tolls beginning April 2013 when we update our transportation rates to account for the higher than estimated delivered volumes.

For 2011, we over collected revenue for our Southern Access Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. In addition, the actual costs recognized in 2011 were lower than the forecasted costs used to calculate the toll charge. As a result, in 2011, we reduced our revenues for the amounts we over collected and recorded a regulatory liability. We began to amortize this regulatory liability on a straight line basis during 2012 to recognize the amounts we previously over collected. For the year ended December 31, 2012, we increased our revenues by $19.1 million, respectively, on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position at December 31, 2012. At December 31, 2011, we had a $19.1 million in regulatory liabilities on our consolidated statements of financial position related to this over collection. We reimbursed these amounts during the year ended December 31, 2012 to our customers through updated transportation rates, which became effective in April 2012, to account for the higher delivered volumes and lower costs.

Alberta Clipper Pipeline

For 2012, we have 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 statement of income with a corresponding increase in the regulatory liability on our consolidated statement of financial position at December 31, 2012 for the differences in transportation volumes. The amounts will be refunded through our tolls beginning April 2013 when we update our transportation rates to account for the higher delivered volumes.

During 2011, we over collected revenue on our Alberta Clipper Pipeline because the actual volumes were higher than forecasted volumes used to calculate the toll charge. As a result, in 2011 we reduced our revenues for the amounts we over collected and recorded a regulatory liability. We began to amortize this regulatory liability on a straight line basis during 2012 to recognize the amounts we previously over collected. For the year ended December 31, 2012, we increased our revenues by $24.5 million on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position at December 31, 2012. At December 31, 2011, we had regulatory liabilities of $24.5 million in our consolidated statements of financial position for the difference in volumes. Throughout the year ended December 31, 2012, these amounts were refunded to our customers through transportation rates, which became effective in April 2012.

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 assets and liabilities associated with this contractual obligation in "Other current assets" and "Accounts payable and other," respectively, on our consolidated statements of financial position. We amortize this contractual obligation on a straight line basis in the following year. At December 31, 2012 and 2011, we had $12.4 million and $2.8 million, respectively, in qualifying volume liabilities related to the Southern Access Pipeline on our statements of financial position.

For 2011, we also incurred liabilities related to contractual obligations with our customers on the Southern Access Pipeline related to qualifying volumes. As a result, in 2011 we reduced our revenues for the amounts due back to our shippers and recorded a liability for the contractual obligation. We amortize the liability on a straight-line basis in the following year. For the periods ended December 31, 2012 and 2011, we increased our revenues by $2.8 million and $4.9 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. We record the assets and liabilities associated with this contractual obligation in “Other current assets” and “Accounts payable and other,” respectively, on our consolidated statements of financial position. At December 31, 2012 and December 31, 2011, we had $6.0 million and $7.3 million, respectively, in property tax over collection liabilities related to our Alberta Clipper Pipeline on our statements of financial position.

For 2011, we also incurred liabilities related to this contractual obligation on the Alberta Clipper Pipeline. As a result, in 2011, 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 year ended December 31, 2012 and 2011, we increased our revenues by $7.3 million and $8.7 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, 2012 and 2011, we had $8.2 million and $26.4 million, respectively, recorded as a regulatory liability on our consolidated statement of financial position for amounts we over collected in connection with the Southern Lights in-service delay. These amounts were not reflected in our revenues.

FERC Transportation Tariffs

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.

Effective April 1, 2011, we filed our annual tariff rate adjustment with the FERC to reflect our projected costs and throughput for 2011 and true-ups for the difference between estimated and actual costs and throughput data for the prior year. Also included was a supplement to our FSM for recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Note 13. *Commitments and Contingencies—Line 6B Pipeline Integrity Plan.*

This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.21 per barrel, to an average of approximately $1.76 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.

On May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in western Canada on Enbridge Pipelines Inc., or Enbridge Pipeline's, Canadian Mainline system to all delivery points on the Lakehead Pipeline system owned by the OLP and delivery points on the Canadian Mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

Effective July 1, 2011, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65% (PPI-FG + 2.65%) should be the oil pricing index for the five year period ending July 2016. The index is used to establish rate ceiling levels for oil pipeline rate changes. The increase in rates is due to an increase in the Producer Price Index for Finished Goods as compared with prior periods. For our Lakehead system, indexing applies only to the base rates and does not apply to the System Expansion Program Phase II, or SEP II, Terrace and Facilities surcharges, which include the Southern Access and Alberta Clipper pipelines.

Effective December 19, 2011, we modified the terms of our transportation tariff on our Ozark system to implement a lottery process to allocate new shipper capacity if and when the number of new shippers nominating on the system precludes any individual new shipper from being allocated a minimum batch. Additionally, we increased the minimum accepted batch size from 10,000 barrels per day, or Bpd, to 30,000 Bpd to ensure accurate delivery measurement.

20. SUBSEQUENT EVENTS

Distribution to Partners

On January 30, 2013, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2013. The distribution was paid to unitholders of record as of February 7, 2013, of our available cash of $198.9 million at December 31, 2012, or $0.54350 per limited partner unit. Of this distribution, $176.1 million was paid in cash, $22.4 million was distributed in i-units to our i-unitholder and $0.4 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, 2013, 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 $13.8 million to the noncontrolling interest in the Series AC, while $6.9 million was paid to us.

Credit Agreement Amendment

On February 8, 2013, we amended the $675 million unsecured senior revolving credit agreement to reflect an increase in the lending commitments to $1.1 billion. We use the unsecured revolving credit agreement to fund our general activities and working capital needs. The amended $1.1 billion credit agreement has terms consistent with our 364-Day Credit Facility. After this amendment, our Credit Facilities provide an aggregate amount of $3.1 billion of bank credit.

21. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for the item labeled “Other” in the “Cash from operating activities” section our consolidated statements of cash flows.

	December 31,		
	2012	2011	2010
		(in millions)	
Discount accretion	$ 0.6	$ 0.7	$ 0.5
Amortization of debt issuance and hedging costs	12.7	19.2	20.6
Deferred income taxes	0.1	(1.1)	0.5
Allowance for equity used during construction	(11.2)	—	(15.3)
Allowance for interest used during construction	(4.5)	—	—
Allowance for doubtful accounts	0.2	0.6	—
Gain on sale of CO2 plant	—	(1.5)	—
Write-down of project costs	4.3	—	—
Other	0.8	2.6	3.4
	$ 3.0	$ 20.5	$ 9.7

22. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Balance Sheet Offsetting

In December 2011, the Financial Accounting Standards Board, or FASB, issued Accounting Standards No. 2011-11, Disclosures about Offsetting Assets and Liabilities, as part of the FASB’s joint project with the

IASB, which requires an entity to disclose information about offsetting and related arrangements. The standard will enable users of financial statements to understand the effect that offsetting and related arrangements have on an entity's financial position. The standard will be effective for annual reporting periods beginning on or after January 1, 2013, with required disclosures presented retrospectively for all comparative period presented. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

In January 2013, the FASB issued Accounting Standards No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which highlights the scope of transactions that are subject to the disclosures about offsetting. The standard clarifies that ordinary trade receivables and receivables are not in the scope of Accounting Standards No. 2011-11, *Disclosures about Offsetting Assets and Liabilities,* discussed above, but applies only to derivatives, repurchase agreements and reverse purchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with specific criteria contained in FASB Accounting Standards Codification or subject to a master netting arrangement or similar agreement. The standard will enable users of financial statements to understand the effect that offsetting and related arrangements have on an entity's financial position. The standard will be effective for annual reporting periods beginning on or after January 1, 2013, with required disclosures, presented retrospectively, for all comparative periods presented. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Accounting Standards Update—Accumulated Other Comprehensive Income

In February 2013, the FASB issued Accounting Standards No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income,* which does not change the current requirements for reporting net income or other comprehensive income in financial statements. The standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. The entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. The standard is effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

23. QUARTERLY FINANCIAL DATA (Unaudited)

	First[(2)(3)]	Second[(1)(3)(5)]	Third[(1)(3)]	Fourth[(1)(3)(4)]	Total
	(in millions, except per unit amounts)				
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
2011 Quarters					
Operating revenue	$ 2,288.9	$ 2,372.0	$ 2,372.2	$ 2,076.7	$ 9,109.8
Operating expense	$ 2,081.4	$ 2,121.6	$ 2,156.6	$ 1,753.4	$ 8,113.0
Operating income	$ 207.5	$ 250.4	$ 215.6	$ 323.3	$ 996.8
Net income	$ 131.8	$ 171.0	$ 134.8	$ 239.6	$ 677.2
Net income attributable to noncontrolling interest	$ 14.7	$ 14.1	$ 12.2	$ 12.2	$ 53.2
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 117.1	$ 156.9	$ 122.6	$ 227.4	$ 624.0
Net income per limited partner unit	$ 0.38	$ 0.51	$ 0.36	$ 0.64	$ 1.99

(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.

(2) Quarterly net income (loss) per limited partner units, for Q1 2011, is presented retrospectively applying the April 21, 2011 two-for-one split of our units.

(3) In 2011, we recognized $35.0 million, $140.0 million and $40.0 million of additional costs during the second, third and fourth quarters, respectively, related to the crude oil release on Line 6B. In 2011, we also recognized $35.0 million, $15.0 million, $85.0 million and $200.0 million of environmental insurance recoveries during the first, second, third and fourth quarters, respectively, related to the crude oil release on Line 6B.

(4) In the fourth quarter of 2011, we recognized approximately $18.0 million of additional expense, net related to accounting misstatements and accounting errors as discussed in Note 14. Trucking and NGL Marketing Business Accounting Matters.

(5) 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.

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, 2012. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective at the reasonable assurance level. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Annual Report on Internal Control Over Financial Reporting

Management of the Partnership is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f).

The Partnership's internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers, and effected by the board of directors of our General Partner, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership's financial statements for external purposes in accordance with generally accepted accounting principles.

The Partnership's internal control over financial reporting includes policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect transactions and dispositions of assets of the Partnership;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with the authorizations of the Partnership's management and directors; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

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

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2012, with the participation of our principal executive and principal financial officers, based on the framework established in *Internal Control—Integrated Framework* 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, 2012.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 119.

REMEDIATION OF MATERIAL WEAKNESS

We disclosed in Item 9A. *Controls and Procedures* of our Annual Report on Form 10-K, for the year ended December 31, 2011, that we had identified a material weakness in our internal control over financial reporting with respect to our wholly-owned trucking and NGL marketing subsidiary related to intentional misconduct and collusion of local management and staff that resulted in accounting misstatements. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the Partnership's annual or interim financial statements will not be prevented or detected on a timely basis. We did not maintain an effective control environment at our wholly-owned trucking and NGL marketing subsidiary and our monitoring of the effectiveness of those controls at that subsidiary was not sufficient to deter or detect that they had been circumvented. An effective control environment is the foundation on which all other components of internal control are based. Specifically:

- An appropriate tone and control culture was not in place associated with the referenced subsidiary, in that certain of its management and employees engaged in intentional misconduct and collusion that violated our policies and procedures, as well as circumvented, through local management's override of, our control processes otherwise in place. Further, these activities were not detected in a timely manner.

- The controls associated with the referenced subsidiary were not effective to ensure that all of the assets and liabilities of the subsidiary were recorded accurately and timely in the instance of collusion by local management and staff.

- The control associated with monitoring the control activities at the referenced subsidiary was not sufficient to detect or deter circumvention of accounting controls or accounting misstatements at the referenced subsidiary in a timely manner.

Management, with the participation of the principal executive officer and principal financial officer, implemented changes to the Partnership's internal control over financial reporting related to the referenced subsidiary to remediate the material weakness described above. The following changes to the Partnership's control environment and monitoring of controls and internal controls as it relates to the referenced subsidiary were implemented:

- We appointed replacements for management at the subsidiary, who separated from the organization.

- A new accounting manager of the subsidiary was appointed.

- We implemented new centralized reporting structures for various groups, including risk management and information technology which were relocated to the Partnership's corporate office.

- We centralized critical control functions, including accounting, contract administration, and risk management into the Partnership's corporate office.

- We retrained all of the personnel in addition to our ongoing annual training process at the referenced subsidiary on our statement of Business Conduct, Whistleblower, and Conflicts of Interest policies.

- We implemented additional process and monitoring controls including review over reconciliations and financial performance addressing completeness, existence, accuracy and valuation of our revenue, cost of natural gas, payables, receivables and inventory. We implemented information technology controls over the reconciliation of key systems to ensure completeness, existence and accuracy of key financial data.

Management has completed the documentation and testing of the remediation measures described above and, as of December 31, 2012, has concluded that the steps taken have remediated the material weakness.

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, 2012.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

We are a limited partnership and have no officers or directors of our own. Set forth below is certain information concerning the directors and executive officers of 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, except for Mark A. Maki and Terrance L. McGill.

Name	Age	Position
Directors and Executive Officers:		
Jeffrey A. Connelly	66	Director and Chairman of the Board
J. Herbert England	66	Director
Rebecca B. Roberts	60	Director
Dan A. Westbrook	60	Director
J. Richard Bird	63	Director
Mark A. Maki	48	President of Enbridge Management, Senior Vice President of General Partner and Director
Terrance L. McGill	58	President of General Partner, Senior Vice President of Enbridge Management and Director
Stephen J. Wuori	55	Executive Vice President—Liquids Pipelines and Director
Leon A. Zupan	57	Executive Vice President—Gas Pipelines and Director
Martha O. Hesse	70	Retired Director and Chairman of the Board
Al Monaco	53	Former Executive Vice President—Gas Pipelines, Green Energy & International and Director
Officers:		
Arthur D. Meyer	56	Senior Vice President—Liquids Pipelines
Richard L. Adams	48	Vice President—U.S. Operations, Liquids Pipelines
Janet L. Coy	55	Vice President—Natural Gas Marketing
E. Chris Kaitson	56	Vice President—Law and Assistant Secretary
John A. Loiacono	50	Vice President—Commercial Activities
Susan E. Miller	54	Vice President—Integrity
Byron C. Neiles	47	Vice President—Major Projects
Stephen J. Neyland	45	Vice President—Finance
Kerry C. Puckett	51	Vice President—Engineering and Operations, Gathering & Processing
William M. Ramos	53	Controller
Allan M. Schneider	54	Vice President—Regulated Engineering and Operations
Bruce A. Stevenson	57	Corporate Secretary
David K. Wudrick	49	Former Treasurer
Darren Yaworsky	42	Treasurer

DIRECTORS AND 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, 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. He has been Chair & Chief Executive Officer of Stahlman-England Irrigation Inc. (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. (fruit beverage manufacturing company). Prior to 1993, Mr. England held various executive positions with John Labatt Limited (brewing company) and its operating companies, Catelli Inc. (food manufacturing company) and Johanna Dairies Inc. (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. From 2006 to 2011, Ms. Roberts was President of Chevron Pipe Line Company. Prior to that, Ms. Roberts was President of Chevron Global Power Generation from 2003 to 2006. She held various other positions within Chevron and its subsidiaries from 1974 to 2003. Ms. Roberts currently serves on the board of directors of Black Hills Corporation, a diversified energy company whose non-regulated businesses generate wholesale electricity and produce natural gas, oil and coal and whose utilities businesses serve natural gas and electric customers.

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. From 2001 to 2005, Mr. Westbrook served as president of BP China Gas, Power & Upstream and as vice-chairman of the board of directors of Dapeng LNG, a Sino joint venture between BP subsidiary CNOOC Gas & Power Ltd. and other Chinese companies. He held executive positions with BP in Argentina, Houston, Russia, Chicago and the Netherlands before retiring from the company in January 2006. From August 2002 to June 2004, Mr. Westbrook served as director and chairman of the finance committee of the International School of Beijing. He also serves on the board of the Carrie Tingley Hospital Foundation in Albuquerque, New Mexico. He is a former director of Ivanhoe Mines, 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 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.

Mark A. Maki

Mark A. Maki was appointed President of Enbridge Management and Senior Vice President of the General Partner and elected as a director of both companies in October 2010. 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 26 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 was elected as a director and appointed as President of the General Partner and Senior Vice President of Enbridge Management in October 2010. Prior to October 2010, Mr. McGill served as a director and President of the General Partner and of Enbridge Management since May 2006. Mr. McGill previously 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.

As the President of the General Partner, 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 in January 2008 and also serves as the Executive Vice President—Liquids Pipelines for the General Partner and Enbridge Management. Mr. Wuori also was appointed President, Liquids Pipelines of Enbridge in October 2010 and had the Major Projects business unit added to his portfolio in January 2012 after which he became President, Liquids Pipelines and Major Projects. 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 was elected as a director of the General Partner and Enbridge Management and appointed as Executive Vice President—Gas Pipelines in April 2012. Prior to that, Mr. Zupan served as Vice President—Operations, Liquids Pipelines for the General Partner and Enbridge Management since 2004. Mr. Zupan also serves Enbridge as President—Gas Pipelines, overseeing Enbridge's U.S. and Canadian gas pipelines businesses since February 2012, prior to which, since October 2010, Mr. Zupan was Senior Vice President—Operations overseeing Enbridge's U.S. and Canadian liquids pipelines. Prior to that, Mr. Zupan served Enbridge as Vice President—Operations since 2004. Mr. Zupan has more than 25 years' experience with Enbridge across a range of businesses.

As a director and Executive Vice President—Gas Pipelines, Mr. Zupan provides our Board insight and in-depth knowledge of our industry and our specific operations and strategies.

Martha O. Hesse

Martha O. Hesse retired from her position as Chairman of the Board in July 2012 and as director of Enbridge, the General Partner and Enbridge Management, including her membership on the Audit, Finance & Risk Committee of the General Partner and Enbridge Management, in August 2012. Ms. Hesse had been elected as a director of the General Partner and Enbridge Management in March 2003 and served as a member of the Audit, Finance & Risk Committee of the General Partner and Enbridge Management and was appointed as Chairman of the Board in 2007. Ms. Hesse was President and Chief Executive Officer of Hesse Gas Company from 1990 through 2003. She served as Chairman of the FERC from 1986 to 1989. Ms. Hesse also served as Senior Vice President of First Chicago Corporation and as Assistant Secretary for Management and Administration of the U.S. Department of Energy. She is a private investor and currently serves as a director of Mutual Trust Financial Group.

Ms. Hesse's contribution to the Board was significant during her tenure.

Al Monaco

Al Monaco resigned as the Executive Vice President—Gas Pipelines, Green Energy & International of the General Partner and Enbridge Management in April 2012 and resigned as director of the General Partner and Enbridge Management in October 2012 when he became President and Chief Executive Officer of Enbridge. Mr. Monaco was elected as a director of the General Partner and Enbridge Management, in October 2010 and resigned as an officer of these entities in April of 2012. In April of 2011, he was elected as Executive Vice President—Gas Pipelines, Green Energy & International of the General Partner and Enbridge Management. Mr. Monaco has served Enbridge as a director and as President and Chief Executive Officer since February 2012, and prior to that he served as President—Gas Pipelines, Green Energy & International of Enbridge since October 2010. Previously, since January 2008, Mr. Monaco was Executive Vice President—Major Projects of the General Partner and Enbridge Management in which he held similar responsibilities with Enbridge. Prior to that, Mr. Monaco was President of Enbridge Gas Distribution Inc., a subsidiary of Enbridge, from September 2006, Senior Vice President, Planning & Development, Enbridge from June 2003, and Vice President, Financial Services, of Enbridge from February 2002. Mr. Monaco was Treasurer of the General Partner from February 2002 and Enbridge Management from its formation until his resignation from those positions in April 2003.

Since 1995, Mr. Monaco has held multiple roles of increasing financial and managerial responsibility during his career with Enbridge. Mr. Monaco brought the Board pipeline industry experience, extensive knowledge in the areas of investor relations, treasury and corporate finance, as well as leadership skills and knowledge of his local community and business environment.

OTHER OFFICERS

Richard L. Adams was elected Vice President—U.S. Operations, Liquids Pipelines of the General Partner and Enbridge Management in February 2010 prior to which he was Vice President—U.S. Engineering and Project Execution, Liquids Pipelines from June 2007 and prior to which he was Vice President—Operations and Technologies from April 2003. Prior to April 2003, he was Director of Technology & Operations for the General Partner and Enbridge Management from 2001, and Director of Field Operations and Technical Services and Director of Commercial Activities for OCENSA/Enbridge in Bogota, Colombia from 1997 to 2001.

Janet L. Coy was appointed Vice President—Natural Gas Marketing of the General Partner and Enbridge Management in October 2010. 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.

E. Chris Kaitson was appointed Vice President—Law of the General Partner and Enbridge Management in May 2007. 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. 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.

Arthur D. Meyer was elected Senior Vice President—Liquids Pipelines of the General Partner and Enbridge Management in September 2012. Since July 2012, Mr. Meyer also serves Enbridge Pipelines as Chief Operating Officer—Liquids Pipelines. Prior to that, in October 2010, Mr. Meyer was named Senior Vice President—Pipeline Integrity and Engineering. Prior titles since joining Enbridge in 1989 include Senior Vice President, Major Projects from July 2010 to October 2010, Senior Vice President—Oil Sands Projects from April 2008 to June 2010 and Senior Vice President—Major Project Execution from February 2007 to March 2008. Mr. Meyer's former titles with Enbridge Pipelines also include Vice President—Technology, and Vice President—Liquids Marketing.

Susan E. Miller was appointed Vice President—Integrity of the General Partner and Enbridge Management in October 2010. Ms. Miller previously served as Vice President—International Business Development for Enbridge since September 2009, including serving as General Manager of the OCENSA crude oil pipeline in Colombia since 2006. Ms. Miller has been an Enbridge employee since 1988.

Byron C. Neiles was appointed Vice President—Major Projects of the General Partner and Enbridge Management in October 2010. Mr. Neiles was named Senior Vice President—Major Projects of Enbridge in November 2011 and previously served Enbridge as Vice President in the Major Projects division since April 2008, prior to which he was Vice President of Enbridge Gas Distribution from 2003 to 2008. Mr. Neiles joined Enbridge in 1994.

Stephen J. Neyland was appointed Vice President—Finance of the General Partner and Enbridge Management in October 2010. 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.

Kerry C. Puckett was appointed Vice President—Engineering and Operations, Gathering & Processing of the General Partner and Enbridge Management in October 2007. 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.

William M. Ramos was appointed Controller of the General Partner and Enbridge Management in October 2010. Prior to his appointment, he served as Assistant Controller and in other managerial roles of the General Partner with responsibility for financial accounting, reporting and control from April 2005. Mr. Ramos served in various management capacities in energy-related companies prior to 2005.

Allan M. Schneider was appointed Vice President—Regulated Engineering and Operations of the General Partner and Enbridge Management in October 2007. Prior to his appointment, he served as Director of Engineering and Operations for Regulated & Offshore and Director of Engineering Services from January 2005. Prior to that, Mr. Schneider was Vice President of Engineering and Operations for Shell Gas Transmission, L.L.C. from December 2000.

Bruce A. Stevenson was appointed Corporate Secretary of the General Partner and Enbridge Management in July 2004. Between 2000 and 2004, Mr. Stevenson held management positions with Reliant Energy, Inc. and Arthur Andersen LLP. Prior to that Mr. Stevenson was General Counsel & Corporate Secretary of Alberta Natural Gas Company Ltd, a Canadian gas processing and transmission company that was acquired by TransCanada Pipelines.

David K. Wudrick resigned as Treasurer of the General Partner and Enbridge Management in October 2012, a position he had held since April 2010. Since August 2012, Mr. Wudrick has served Enbridge as Senior Director—Strategic Development for Liquids Pipelines, prior to which he was Senior Director—Finance for Enbridge. Previously, from 2007 he had served Enbridge as Director—Treasury and from 2005 he was Treasurer of Enbridge Management Service Inc., a wholly-owned subsidiary of Enbridge.

Darren J. Yaworsky was appointed Treasurer of the General Partner and Enbridge Management in October 2012. 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 2012 and prior years were timely made, except that each of J. Richard Bird, one of our directors, and Arthur D. Meyer, one of our officers, did not timely file a Form 3 to report the number of units beneficially held by him.

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 29, 2012.

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. Martha O. Hesse resigned as a director and as a member of the Audit Committee on August 14, 2012, and Rebecca B. Roberts was elected to fill the Audit Committee vacancy on July 30, 2012. Jeffrey A. Connelly resigned as chairman of the Audit Committee on July 30, 2012, and J. Herbert England was subsequently elected as chairman of the Audit Committee. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the report of the independent registered public accounting firm. The Audit Committee also reviews the scope and quality, including the independence and objectivity, of the independent and internal auditors and the fees paid for both audit and non-audit work and makes recommendations concerning audit matters, including the engagement of the independent auditors, to the Board of Directors.

The charter of the Audit Committee is available on our website at *www.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. 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 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 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, 2012 were:

- Terrance L. McGill, President of the General Partner, Senior Vice President of Enbridge Management and Director
- Mark A. Maki, President of Enbridge Management, Senior Vice President of the General Partner and Director
- Stephen J. Neyland, Vice President—Finance
- Stephen J. Wuori, Executive Vice President—Liquids Pipelines and Director
- Leon A. Zupan, Executive Vice President—Gas Pipelines and Director
- Arthur D. Meyer, Senior Vice President—Liquids Pipelines
- Al Monaco, Former President—Gas Pipelines, Green Energy & International

Messrs. Wuori and Zupan are also executive officers of Enbridge, and Mr. Meyer is also an executive officer of Enbridge Pipelines. Mr. Wuori serves as President, Liquids Pipelines & Major Projects and Mr. Zupan serves as President, Gas Pipelines of Enbridge, while Mr. Meyer serves as Chief Operating Officer, Liquids Pipelines of Enbridge Pipelines. Mr. Monaco served as a director of our General Partner and Enbridge Management until his resignation on October 1, 2012 and also served as President, Gas Pipelines, Green Energy & International of our General Partner and Enbridge Management until his resignation on April 4, 2012.

Mr. Monaco became President & Chief Executive Officer of Enbridge in 2012. Since Messrs. Wuori and Zupan are also executive officers of Enbridge, the Human Resources and Compensation Committee of the board of directors of Enbridge, or the HRC Committee, approves the elements of compensation for them based on the recommendation of the President & Chief Executive Officer of Enbridge considering his position within Enbridge on an enterprise-wide basis. Mr. Meyer's compensation is approved by Mr. Wuori. Each of the executive officers completes a self-assessment. Mr. Monaco is evaluated by the HRC Committee and the Board of Directors of Enbridge.

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 in the aggregate before being recommended to the HRC Committee. The Enbridge executive leadership team, the President & Chief Executive Officer of Enbridge and the HRC Committee do not review the elements of compensation for Messrs. McGill, Maki and Neyland on an individual basis. Mr. Zupan, a director of our General Partner and Enbridge Management and a member of the Enbridge executive leadership team, makes compensation recommendations for Messrs. McGill, Maki and Neyland, which are subject to the Enbridge enterprise-wide review process described above. Enbridge's President & Chief Executive Officer approves the aggregate of all 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.

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:

2012	2011	2010	2009	2008
14%	17%	17%	12%	9%

The elements of total compensation in 2012 for senior management of Enbridge, which include Messrs. Wuori, Zupan and Monaco, 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.

The elements of compensation for Mr. Meyer are similar to those described above, except that he is not eligible for performance-based stock options. The elements of compensation for Messrs. McGill, Maki and Neyland 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 2012 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
Terrance L. McGill *President of the General Partner, Senior Vice President of Enbridge Management and Director*	40%	0-80%	25%	50%	25%
Mark A. Maki *President of Enbridge Management, Senior Vice President of the General Partner and Director*	40%	0-80%	25%	50%	25%
Stephen J. Neyland *Vice President—Finance*	35%	0-70%	25%	50%	25%
Stephen J. Wuori[(2)] *Executive Vice President—Liquids Pipelines and Director*	65%	0-130%	25%	50%	25%
Leon A. Zupan[(3)] *Executive Vice President—Gas Pipelines and Director*	50%	0-100%	25%	50%	25%
Arthur D. Meyer[(4)] *Senior Vice President—Liquids Pipelines*	45%	0-90%	25%	50%	25%
Al Monaco[(5)] *Former Executive Vice President, Gas Pipelines, Green Energy and International and Former Director*	90%	0-180%	60%	20%	20%

(1) All values are expressed as percentages of base salary.

(2) Effective March 1, 2012, Mr. Wuori's STIP target increased from 50% to 65% as a result of the addition in his portfolio of responsibilities.

(3) Effective June 15, 2012, Mr. Zupan's STIP target increased from 40% to 50% as a result of his appointment to Executive Vice President, Gas Pipelines.

(4) Effective June 15, 2012, Mr. Meyer's STIP target increased from 40% to 45% as a result of his appointment to Chief Operating Officer—Liquids Pipelines of Enbridge Pipelines.

(5) Effective March 1, 2012, Mr. Monaco's STIP target increased from 50% to 75% as a result of his appointment to President, Enbridge Inc. Effective October 1, 2012, his STIP target increased again from 75% to 90% as a result of his appointment to President & Chief Executive Officer of Enbridge.

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 Enbridge's corporate named executives' short-term incentive award at 25% for all NEOs exclusive of Mr. Monaco which is at 60%. Enbridge's 2012 EPS guidance range was $1.58 CAD – $1.74 CAD as approved by the Enbridge Board prior to the start of 2012. Actual performance was $1.62 CAD. Adjustments are made to ensure the result is a fair reflection of performance. Approximately $639 million CAD of losses were adjusted out of the calculation, including mark to market losses and losses from asset impairment. The corporate multiplier ranges from 0 to 2.0, with 1.0 meaning that the performance measure was met.

During 2012, Enbridge management undertook, with Enbridge Board approval, a supplementary financing plan that included $2.8 billion CAD of common equity, preferred equity and debt pre-funding actions that were not provided for in the original budget, prompted by the significant expansions to the Enbridge five-year growth capital plan, which emerged over the course of the year. Although these actions had an adverse impact on 2012 Enbridge's EPS, they were necessary and prudent steps to support the medium and long-term objectives of Enbridge. 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 impact of the specific pre-funding actions noted above, resulted in an adjusted EPS of $1.676 CAD (versus $1.62 CAD per share) and a short-term corporate multiplier of 1.20 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, other than Mr. Monaco, 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. 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 1.02 out of 2.0. Mr. Zupan's performance measure is calculated at 17% for the Liquids business unit for his contribution during the first part of the year, 50% for the Gas Transportation business unit and 33% for the Gas Development business unit, resulting in a business unit multiplier of 1.09 out of 2.0. Mr. Maki's performance measure is calculated at 50% for the Gas Transportation business unit and 50% for the Shared Services business unit, resulting in a business unit multiplier of 1.04 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 1.11 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 1.31 out of 2.0. Mr. Meyer's performance measure is calculated at 100% for the Liquids business unit, resulting in a business unit multiplier of 1.27 out of 2.0. Mr. Monaco's performance measure takes into consideration performance across multiple business units under his current role as President & Chief Executive Officer of Enbridge, resulting in a business unit multiplier of 1.46 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 Management System Leader Enhancements	5%	1.89	0.38
		Safety Observations	5%		
		Total Recordable Injury Frequency	5%		
		Preventable Motor Vehicle Accidents	5%		
Operations & Integrity	20%	Plant Reliability	5%	1.10	0.22
		Integrity Management Program Inspections	5%		
		Reportable Releases	5%		
		Non-Reportable Releases	5%		
Financial	40%	Adjusted Net Income of EEP Gas, Enbridge Offshore Assets and Joint Venture Gas Assets	40%	0.04	0.02
Employee Engagement & Compliance	20%	Health Risk Assessment Participation	5%	1.77	0.35
		Compliance Training Participation	5%		
		SOX Compliance	5%		
		Risk Compliance	5%		
Business Unit Performance Multiplier					**0.97**

Gas Development					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Rating**	**Performance Multiplier**
Operations, Safety & Integrity	25%	Transition of Cabin Plant	5%	1.79	0.45
		HSMS Leader Enhancements	2.5%		
		Safety Observations	2.5%		
		Total Recordable Injury Frequency	2.5%		
		Preventable Motor Vehicle Incidents	2.5%		
		OSHA Recordable Incidents	2.5%		
		Motor Vehicle Incidents	2.5%		
		Environmental Regulatory Compliance	5%		
Financial	40%	Budget Earnings	40%	0.09	0.03
Business Development Activities	35%	Contracting Strategies & New Investments	35.0%	2.00	0.70
Business Unit Performance Multiplier					**1.18**

Shared Services					
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Rating**	**Performance Multiplier**
Safety	20%	Health & Safety Management System Leader Enhancements	5%	1.89	0.38
		Safety Observations	5%		
		Total Recordable Injury Frequency	5%		
		Preventable Motor Vehicle Accidents	5%		
Operations & Integrity	20%	Plant Reliability	5%	1.10	0.22
		Integrity Management Program Inspections	5%		
		Reportable Releases	5%		
		Non-Reportable Releases	5%		
Financial	40%	Adjusted Net Income of EEP gas and Enbridge offshore assets	20%	0.41	0.16
		Adjusted Net Income of EEP liquids and Enbridge liquid pipelines	20%		
Employee Engagement & Compliance	20%	Health Risk Assessment Participation	5%	1.77	0.35
		Compliance Training Participation	5%		
		Sox Compliance	5%		
		Risk Compliance	5%		
Business Unit Performance multiplier					**1.11**

Liquids Pipelines					
Performance Measure	**Weight**	**Sub Measure % Weightings**		**Rating**	**Performance Multiplier**
Environmental, Health & Safety	15%	Total Recordable Injury Frequency	3.75%	1.2	0.18
		Motor Vehicle Incidents	3.75%		
		Health & Safety Incident Investigation & Corrective Actions	3.75%		
		Safety Observations	3.75%		
Governance & Compliance	5%	Governance Composite	5%	1.6	0.08
Financial	50%	Enbridge Liquids Pipelines Earnings	29%	1.2	0.59
		EEP Liquids Pipelines Earnings	8.5%		
		Enbridge Pipelines Saskatchewan Inc. Earnings	2.5%		
		Enbridge Liquids Pipelines Growth	10%		
Pipeline Integrity	12%	Inspection and Remediation Programs	12%	0.9	0.10
Leak Detection	4%	Line Segment Improvements	4%	1.9	0.08
Operational Risk Management	4%	Framework, Initiative, & Compliance System	4%	1.5	0.06
Customer Satisfaction	5%	Capacity, Quality & Degradation	5%	1.8	0.09
Employee Retention & Development	5%	Employee Retention	2.5%	1.9	0.09
		Employee Attraction	2.5%		
		Business Unit Performance multiplier			**1.27**

Major Projects				
Performance Measure	**Weight**	**Sub Measures & Weightings**	**Rating**	**Performance Multiplier**
Schedule	32%	Reach key milestone and forecast in-service delivery	1.14	0.36
Cost	24%	Development and execution of projects relative to budget	1.62	0.39
Quality	10.5%	Quality standards throughout lifecycle	1.78	0.19
Compliance	9.5%	Compliance with regulation and protection of the environment	1.65	0.16
Safety	14%	Leading and lagging measures to achieving best-in-class performance	1.14	0.16
People	10%	Employee attraction, retention and engagement	2.00	0.20
			Performance Multiplier	**1.46**
			Management Adjustment[(1)]	**0.07**
			Business Unit Performance Multiplier	**1.53**

(1) Management approved an adjustment due to Major Projects exceeding all targets.

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, by Mr. Wuori for Mr. Meyer and by Mr. Zupan for Messrs. McGill, Maki, and Neyland. The HRC Committee approves Mr. Monaco's recommendations for Messrs. Wuori and Zupan. Mr. Monaco is evaluated by the HRC Committee and the Board of Directors of Enbridge.

Summary of 2012 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)
Terrance L. McGill	25% x 1.20 = 0.30	50% x 1.02 = 0.51	25% x 1.55 = 0.39	1.20
Mark A. Maki	25% x 1.20 = 0.30	50% x 1.04 = 0.52	25% x 1.60 = 0.40	1.22
Stephen J. Neyland	25% x 1.20 = 0.30	50% x 1.11 = 0.56	25% x 1.65 = 0.41	1.27
Stephen J. Wuori	25% x 1.20 = 0.30	50% x 1.31 = 0.65	25% x 1.75 = 0.44	1.39
Leon A. Zupan	25% x 1.20 = 0.30	50% x 1.09 = 0.54	25% x 1.60 = 0.40	1.24
Arthur D. Meyer	25% x 1.20 = 0.30	50% x 1.27 = 0.64	25% x 1.65 = 0.41	1.35
Al Monaco	60% x 1.20 = 0.72	20% x 1.46 = 0.30	20% x 1.85 = 0.37	1.39

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
Terrance L. McGill	$ 369,850	40%	1.20	$ 177,528	$ 177,160
Mark A. Maki	335,300	40%	1.22	163,626	183,630
Stephen J. Neyland	237,930	35%	1.27	105,760	120,550
Stephen J. Wuori[2][3]	700,280	65%	1.39	632,703	610,554
Leon A. Zupan[4]	400,000	50%	1.24	248,000	239,830
Arthur D. Meyer[2][5]	400,160	45%	1.35	243,097	255,432
Al Monaco[2][6]	1,000,400	90%	1.39	1,251,500	1,033,964

(1) The calculated STIP may differ from the amounts presented due to rounding.

(2) The dollar amounts presented for Messrs. Wuori, Meyer and Monaco have been converted from Canadian dollars, or CAD, to United States dollars, or USD, using the average exchange rate for 2012 of $0.9996 CAD = $1 USD.

(3) Effective March 1, 2012, Mr. Wuori's STIP target increased from 50% to 65% as a result of the increase in his portfolio of responsibilities, which resulted in a prorated STIP amount.

(4) Effective June 15, 2012, Mr. Zupan's STIP target increased from 40% to 50% as a result of his promotion to Executive Vice President, Gas Pipelines, which resulted in a prorated STIP amount.

(5) Effective June 15, 2012, Mr. Meyer's STIP target increased from 40% to 45% as a result of his appointment to Chief Operating Officer, Enbridge Pipelines, which resulted in a prorated STIP amount.

(6) Effective March 1, 2012, Mr. Monaco's STIP target increased from 50% to 75% as a result of his appointment to President, Enbridge Inc. Effective October 1, 2012, his STIP target increased again from 75% to 90% as a result of his appointment to President & Chief Executive Officer of Enbridge, which resulted in a prorated STIP amount.

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. Mr. Wuori may recommend adjustments to the calculated STIP for Mr. Meyer, while Mr. Zupan may also recommend adjustments to the calculated STIP for Messrs. McGill, Maki, and Neyland, which recommendations are reviewed by Enbridge's executive leadership team for fairness and consistency with enterprise-wide compensation. Messrs. Meyer, Maki and Neyland 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 four plans that make up its medium and long-term incentive program for senior management:

- A performance stock unit plan, or PSUP, which includes three-year phantom shares with performance conditions that impact payout;

- A performance-based stock option plan, or PSOP, that includes eight-year options to acquire Enbridge common shares with performance and time vesting conditions;

- An incentive stock option plan, or ISOP, which includes 10-year stock options to acquire Enbridge common shares with time vesting conditions; and

- A restricted stock unit plan, or RSUP, which grants Restricted Stock Units, or RSUs, to director and manager-level employees on an annual basis. RSUs have the same value as a common share of Enbridge stock, but are not traded in external financial markets. Mr. Neyland is the only NEO that participated in this plan for the year ended December 31, 2010.

Only the Enbridge executive leadership team, which includes Messrs. Wuori, Zupan and Monaco, are eligible to receive grants under the PSOP.

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 targets 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:

NEO	Target Medium & Long-term Incentive Grant[1]	Amount Each Plan Contributes to Total Target Grant[1]		
		Performance Stock Units	Performance-Based Stock Options	Incentive Stock Options
Terrance L. McGill	85.0%	25.5%	—	59.5%
Mark A. Maki	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%
Arthur D. Meyer	100.0%	30.0%	—	70.0%
Al Monaco	330.0%	115.0%	100.0%	115.0%

(1) All values are expressed as percentages of base salary.

With the exception of Messrs. Monaco, Wuori and Zupan, actual award values, expressed as a percentage of base salary, range between 0% and 200% of the target medium and long-term incentive opportunity, based on individual performance history, succession potential, retention considerations and market competitiveness.

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 2012 grants, each of which weighted 50%, were established for the grant: EPS and price to earnings ratio, or P/E Ratio.

The EPS performance reflects Enbridge's commitment to its shareholders to achieve earnings that meet or exceed industry growth rates. Enbridge established the EPS target to reflect performance that would be consistent with the average growth rate forecast of peer companies over a comparable time period. The EPS required to achieve a two multiplier (the maximum) would demonstrate achievement of compound annual growth consistent with exceptional industry growth rate and would represent exceptional performance to the investment community. Performance must at least meet 3% compound annual growth in EPS for a threshold payment, below which the multiplier would be zero.

The second performance criterion is the Enbridge P/E Ratio relative to a selected 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 75^{th} percentile results in a multiplier of one and performance above the 75^{th} 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, Zupan and Monaco, with its shareholders by tying vesting to the achievement of defined performance criteria. Once the performance targets 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 targets 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. Zupan, Wuori and Monaco in 2012. The performance criteria for the 2012 performance stock options are Enbridge common share price targets 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, and in 2008 to Mr. Monaco when he was appointed to the Enbridge executive leadership team. The performance criteria for the 2007 and 2008 performance stock options are Enbridge common share price targets 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, 2012, the common share price targets for the 2007 and 2008 grants have been met, therefore 100% of the 2007 grant is exercisable and 80% of the 2008 grant is exercisable. As of December 31, 2012, the common share price targets 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 the grant is ten years.

RSUP

The RSUP is a plan that awards RSUs to director and manager-level employees based on their base salary, an RSU target incentive opportunity and the common share price. Additionally the number of units can be adjusted for factors including performance, skill, potential and external market competitiveness. Grants are made infrequently, typically in February, effective January 1 of each year and have a 35-month term. Throughout the term, units are added to the grants as if dividends were received and reinvested into additional units based on the actual dividend rate for common shares of Enbridge stock. At the end of the term, the units are paid in cash based on the weighted average price of an Enbridge common share on the NYSE for 20 trading days prior to the end of the term. Mr. Neyland is the only NEO that participated in this plan for the year ended December 31, 2010.

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. Monaco, Meyer and Wuori. 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, Zupan 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, 2012, 2011 and 2010, for amounts reimbursed to us by Enbridge and its affiliates for the portion of the NEOs' compensation allocated to us. For 2012, the percentage of time estimated to be spent by each of the NEOs on our matters was:

- Terrance L. McGill – 90%
- Mark A. Maki – 95%
- Stephen J. Neyland – 90%
- Stephen J. Wuori – 25%
- Leon A. Zupan – 57%
- Arthur D. Meyer – 20%
- Al Monaco – 10%

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.

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 2012, 2011 and 2010, 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, 2012, 2011 and 2010, 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 (a)	Year (b)	Salary ($) (c)	Stock Awards[1] ($) (e)	Option Awards[2] ($) (f)	Non-Equity Incentive Plan Compen-sation[3] ($) (g)	Change in Pension Value and Nonqualified Deferred Compen-sation Earnings ($) (h)	All Other Compen-sation[4] ($) (i)	Total ($) (j)	Approximate Percentage of Time Devoted to Enbridge Energy Partners, L.P. (%)	Approximate Amount Allocated to Enbridge Energy Partners, L.P. ($)
Terrance L. McGill	2012	367,660	712,584	415,786	177,160	371,000	35,822	2,080,012	90	1,809,538
President of the General Partner, Senior Vice President of Enbridge Management and Director	2011	366,309	734,843	435,372	237,060	442,000	35,853	2,251,437	86	2,080,741
	2010	354,348	707,024	291,550	223,010	281,000	35,853	1,892,785	77	1,692,380
Mark A. Maki	2012	344,475	590,857	289,938	183,630	813,000	34,246	2,256,146	95	1,896,178
President of Enbridge Management, Senior Vice President of the General Partner and Director	2011	336,588	535,317	237,103	216,340	781,000	33,996	2,140,344	86	1,974,238
	2010	294,639	447,118	159,653	202,740	370,000	33,996	1,508,146	77	1,336,788
Stephen J. Neyland	2012	241,198	249,187	163,217	129,750	162,000	33,532	978,884	90	824,613
Vice President—Finance	2011	234,998	151,454	125,248	139,150	157,000	33,496	841,346	86	763,286
	2010	213,027	75,566	81,055	96,360	75,000	24,897	565,905	79	491,208
Stephen J. Wuori[5][8]	2012	684,520	3,031,025	1,506,549	610,554	2,550,000	85,911	8,468,559	25	400,335
Executive Vice President—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
	2010	563,815	2,395,240	537,411	333,141	1,628,000	79,692	5,537,299	40	396,715
Leon A. Zupan[9]	2012	388,533	485,620	466,738	239,830	894,000	101,148	2,575,869	57	518,792
Executive Vice President—Gas Pipelines and Director	2011	—	—	—	—	—	—	—	—	—
	2010	—	—	—	—	—	—	—	—	—
Arthur D. Meyer[7][10]	2012	375,046	656,416	441,747	255,432	787,000	50,346	2,565,987	20	212,258
Senior Vice President—Liquids Pipelines	2011	—	—	—	—	—	—	—	—	—
	2010	—	—	—	—	—	—	—	—	—
Al Monaco[6][8]	2012	804,488	3,158,157	1,006,443	1,033,964	1,776,000	85,355	7,864,407	10	153,695
Former Executive Vice President Gas Pipelines, Green Energy & International and Former Director	2011	524,467	2,505,293	550,210	513,083	834,000	71,964	4,999,017	40	1,182,137
	2010	473,488	2,085,200	470,488	334,113	669,000	67,578	4,099,867	20	267,480

(1) The compensation expense associated with Performance Stock Units, or PSUs, for each NEO, and the Restricted Stock Units, or RSU's with respect to Mr. Neyland that are reflected in this column represent one-third of the market value for each year the PSUs and RSUs 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, 2012 includes one-third of the market values for PSUs and RSUs issued in 2012, 2011 and 2010. In 2012, the compensation expense recorded for PSUs granted in 2012, 2011 and 2010 include performance multipliers for the respective years, which are estimated at December 31, 2012 to be 2.0 and the actual multiplier of 2.0 for 2011 and 2010 based upon the expected or achieved levels of performance in relation to established targets for each year. 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. Refer also to *Footnote 3* of the *Grants of Plan—Based Awards* table for additional discussion regarding the PSUs. Mr. Neyland received RSUs in 2010. The market value for each PSU and RSU grant represents the weighted average closing price of an Enbridge common share as quoted on the NYSE for the USD denominated PSUs and RSUs and the Toronto Stock Exchange, or TSX, for CAD denominated PSUs for the 20 consecutive days prior to the end of the performance period. PSUs granted for 2012, 2011 and 2010 were denominated in both USD and CAD, while RSUs granted to Mr. Neyland are denominated in only USD. 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 performance period December 31, 2012, 2011 and 2010, respectively. The PSUs and RSUs were granted on January 1, 2012, 2011 and 2010, respectively. The actual payout amounts for the 2009 PSUs that vested in 2012 were based on average share prices of $42.27 USD and $41.69 CAD, for the respective USD denominated PSUs and CAD denominated

PSUs and $39.39 USD for the 2009 RSUs that vested in 2012. Compensation expense as reported in the Summary Compensation Table above for Stock Awards has been determined using the following assumptions:

	2012	2011	2010[(a)]	2009[(a)]	2008[(a)]
End of Period Market Value USD	$ 42.27	$ 35.75	$ 27.71	$ 22.41	$ 15.70
End of Period Market Value CAD	$ 41.69	$ 36.38	$ 27.92	$ 23.57	$ 19.36
20-day average $1CAD to USD exchange rate before January 1	$1.0104	$0.9768	$0.9927	$1.0544	$1.2343
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	2.00
Assumed performance multiplier	2.00	2.00	2.00	2.00	N/A

(a) Where appropriate, prices adjusted for the May 2011 Enbridge stock split.

(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, Zupan and Monaco 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	2012	2011	2010	2012	2011	2010
Expected option term in years	6	6	6	8	N/A	N/A
Expected volatility	22.80%	22.40%	34.10%	16.10%	N/A	N/A
Expected dividend yield	2.95%	3.41%	3.64%	2.80%	N/A	N/A
Risk-free interest rate	1.17%	2.80%	2.92%	1.60%	N/A	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. The fair values of all grants on the grant date have been converted to USD using the average exchange rates, representing the exchange rate for the period during which the expense was recognized.

	ISOP			PSOP		
	2012	2011	2010[(a)]	2012	2011	2010
Exercise price in CAD	$ 38.34	$ 28.78	$ 23.30	$ 39.34	N/A	N/A
Exercise price in USD	$ 38.65	$ 28.99	$ 21.97	$ 39.77	N/A	N/A
Grant date exchange rate for $1 USD	$0.9888	$0.9885	$1.0426	$0.9891	N/A	N/A

(a) Where appropriate, prices adjusted for the May 2011 Enbridge stock split.

	ISOP			PSOP		
	2012	2011	2010[(a)]	2012	2011	2010
Vesting period in years	4	4	4	8	N/A	N/A
Option fair value on grant date in CAD	$ 5.00	$ 4.00	$ 4.66	$ 4.25	N/A	N/A
Option fair value on grant date in USD	$ 6.11	$ 5.11	$ 5.95	$ 4.30	N/A	N/A
Average full year exchange rate for $1 USD	$0.9996	$0.9891	$1.0299	$0.9884	N/A	N/A

(a) Where appropriate, fair values adjusted for the May 2011 Enbridge stock split.

(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 Mr. Neyland includes an additional amount received during 2012 that was awarded for additional effort and personal commitment.

(4) The table which follows labeled “All Other Compensation” sets forth the elements comprising the amounts presented in this column.

(5) 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. Mr. Wuori is 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, 2012, 2011 and 2010 of $0.9996 CAD = $1USD, $0.9891 CAD = $1USD and $1.0299 CAD = $1USD, respectively. The costs associated with the PSUs and options Mr. Wuori was granted in 2012, 2011 and 2010 were borne by Enbridge and other affiliates where he is also an officer. We are allocated a portion of the remaining elements of Mr. Wuori’s 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.

(6) Mr. Monaco 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. Mr. Monaco is 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, 2012, 2011 and 2010 of $0.9996 CAD = $1USD, $0.9891 CAD = $1USD and $1.0299 CAD = $1 USD, respectively. The costs associated with the PSUs and options Mr. Monaco was granted in 2012, 2011 and 2010 were borne by Enbridge and other affiliates where he is also an officer.

(7) Mr. Meyer is also an executive officer of Enbridge Pipelines with responsibility for other affiliates of Enbridge in addition to those for our General Partner and Enbridge Management. Mr. Meyer is compensated by affiliates of Enbridge in CAD, which we have converted to USD using the weighted average exchange rate for the entire year ended December 31, 2012 of $0.9996 CAD = $1USD. The costs associated with the PSUs and options Mr. Meyer was granted in 2012 were borne by Enbridge and other affiliates where he is also an officer. We are allocated a portion of the remaining elements of Mr. Meyer's 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) Messrs. Wuori and Monaco were elected officers of Enbridge Management and our General Partner in January 2008, prior to which they held other responsibilities with Enbridge.

(9) Mr. Zupan was elected as Executive Vice President—Gas Pipelines in April 2012 prior to which he held other responsibilities with Enbridge.

(10) Mr. Meyer was elected as an officer of Enbridge Management and our General Partner in September 2012 prior to which he held other responsibilities with Enbridge Pipelines.

ALL OTHER COMPENSATION
(For the years ended December 31, 2012, 2011 and 2010)

Name	Year	Flexible Benefits(2) $	401(k) Matching Contributions(3) $	Other Benefits(4) $	Total
Terrance L. McGill	2012	20,000	12,500	3,322	35,822
	2011	20,000	12,250	3,603	35,853
	2010	20,000	12,250	3,603	35,853
Mark A. Maki	2012	20,000	12,500	1,746	34,246
	2011	20,000	12,250	1,746	33,996
	2010	20,000	12,250	1,746	33,996
Stephen J. Neyland	2012	20,000	11,786	1,746	33,532
	2011	20,000	11,750	1,746	33,496
	2010	12,500	10,651	1,746	24,897
Stephen J. Wuori(1)	2012	74,481	—	11,430	85,911
	2011	72,028	—	146,196	218,224
	2010	68,398	—	11,294	79,692
Leon A. Zupan(1)	2012	65,138	7,039	28,971	101,148
	2011	—	—	—	—
	2010	—	—	—	—
Arthur D. Meyer(1)	2012	47,963	—	2,383	50,346
	2011	—	—	—	—
	2010	—	—	—	—
Al Monaco(1)	2012	80,019	—	5,336	85,355
	2011	62,326	—	9,638	71,964
	2010	58,759	—	8,819	67,578

(1) The amounts reported in this table for Messrs. Wuori, Meyer, and Monaco, our NEOs domiciled in Canada, have been converted from CAD to USD using the average exchange rate for the years ended December 31, 2012, 2011 and 2010 of $0.9996 CAD = $1 USD, $0.9891 CAD = $1 USD and $1.0299 CAD = $1 USD, respectively. Mr. Zupan's amounts were converted using the same rates, excluding the 401k matching contribution amount which was 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; or paid as additional compensation.

(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, 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 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 2010 through 2012 to our U.S. domiciled NEOs are denominated in USD while those granted to NEOs domiciled in Canada are denominated in CAD. The three tables which follow set forth information concerning performance stock units and stock options granted during the year ended December 31, 2012, outstanding at December 31, 2012 and the number of awards vested and exercised during the year ended December 31, 2012 by each of the NEOs.

GRANTS OF PLAN-BASED AWARDS

Name (a)	Plan Name[1] (b)	Approval Date (b)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[2] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[3] Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Option Awards: Number of Securities Underlying Options[4][5] (#) (j)	Exercise or Base Price of Option Awards[4][5] ($/Sh) (k)	Date Fair Value of Stock and Option Awards[3][4][5] ($) (l)
Terrance L. McGill	PSUP	1-Feb-12	1-Jan-12	—	—	—	3,094	4,950	9,900	—	—	176,963
	ISOP	1-Feb-12	2-Mar-12	—	—	—	—	—	—	68,050	38.65	415,786
	STIP	1-Feb-13	1-Feb-13	—	147,940	295,880	—	—	—	—	—	—
Mark A. Maki	PSUP	1-Feb-12	1-Jan-12	—	—	—	2,781	4,450	8,900	—	—	159,088
	ISOP	1-Feb-12	2-Mar-12	—	—	—	—	—	—	61,650	38.65	376,682
	STIP	1-Feb-13	1-Feb-13	—	134,120	268,240	—	—	—	—	—	—
Stephen J. Neyland	PSUP	1-Feb-12	1-Jan-12	—	—	—	2,250	3,600	7,200	—	—	128,700
	ISOP	1-Feb-12	2-Mar-12	—	—	—	—	—	—	39,100	38.65	238,901
	STIP	1-Feb-13	1-Feb-13	—	83,276	166,551	—	—	—	—	—	—
Stephen J. Wuori	PSUP	1-Feb-12	1-Jan-12	—	—	—	10,500	16,800	33,600	—	—	617,586
	ISOP	1-Feb-12	2-Mar-12	—	—	—	—	—	—	117,300	38.77	593,127
	PSOP	1-Aug-12	15-Aug-12	—	—	—	—	—	—	617,600	39.77	2,653,673
	STIP	1-Feb-13	1-Feb-13	—	455,182	910,364	—	—	—	—	—	—
Leon A. Zupan	PSUP	1-Feb-12	1-Jan-12	—	—	—	3,219	5,150	10,300	—	—	189,320
	ISOP	1-Feb-12	2-Mar-12	—	—	—	—	—	—	82,850	38.77	418,931
	PSOP	1-Aug-12	15-Aug-12	—	—	—	—	—	—	169,400	39.77	727,869
	STIP	1-Feb-13	1-Feb-13	—	200,000	400,000	—	—	—	—	—	—
Arthur D. Meyer	PSUP	1-Feb-12	1-Jan-12	—	—	—	3,438	5,500	11,000	—	—	202,186
	ISOP	1-Feb-12	2-Mar-12	—	—	—	—	—	—	88,800	38.77	449,017
	STIP	1-Feb-13	1-Feb-13	—	180,072	360,144	—	—	—	—	—	—
Al Monaco	PSUP	1-Feb-12	1-Jan-12	—	—	—	13,250	21,200	42,400	—	—	779,335
	ISOP	1-Feb-12	2-Mar-12	—	—	—	—	—	—	147,500	38.77	745,834
	PSOP	1-Aug-12	15-Aug-12	—	—	—	—	—	—	1,058,800	39.77	4,549,399
	STIP	1-Feb-13	1-Feb-13	—	900,360	1,800,720	—	—	—	—	—	—

(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 qualified stock option plan.

c. PSOP refers to the Enbridge Performance Stock Option Plan (2012), a performance-based, incentive stock option plan.

d. 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 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 2012 was $35.75 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, 2012. The grant date fair value for each PSU granted to each of our Canadian based NEOs was $36.38 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, 2012. We have converted the grant date fair value for the Canadian PSU grants made from CAD to USD using an exchange rate of $0.9768 CAD = $1 USD, representing the weighted average noon rate for 20 trading days immediately preceding the performance period that began on January 1, 2012.

(4) The ISOP is administered by a committee of the Enbridge board of directors and if an option is granted during a trading blackout period, the exercise price of an option grant is determined as the weighted average trading price of an Enbridge common share on the TSX or NYSE for the five trading days immediately prior to the effective date of the option. In the event an option grant is granted during a period a trading blackout is not in effect, the exercise price of the option grant is equal to the last reported sales price on the TSX or NYSE for the day immediately preceding the grant date. During 2012, 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 $38.34 CAD for Canadian-domiciled NEOs and $38.65 USD for NEOs domiciled in the United States.

The amounts included as the grant date fair value for the 2012 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;
22.8% expected volatility;	19.0% expected volatility;
2.95% expected dividend yield; and	2.95% expected dividend yield; and
1.17% risk free interest rate.	1.45% risk free interest rate.

The fair value of options granted as computed using these assumptions is $6.11 USD or $5.00 CAD. The $6.11 CAD option value and the $38.34 CAD exercise price have been converted to USD using an exchange rate of $0.9888 CAD = $1 USD representing the noon buying rate in New York for transfers of CAD on the grant date of March 2, 2012. 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, Meyer 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.

(5) The Enbridge Performance Stock Option Plan is administered by the HRC Committee and if a performance option is issued during a trading blackout period, the exercise price of a performance option grant is determined as the weighted average trading price of an Enbridge common share on the TSX or NYSE for the five trading days immediately prior to the effective date of the performance option. In the event an option grant is issued during a period a trading blackout is not in effect, the exercise price of the performance option grant is equal to the last reported sales price on the TSX or NYSE for the day immediately preceding the grant date. PBSOs are similar to the incentive stock options, except that the quantities become exercisable subject to both the achievement of specified common share price targets and time requirements.

The term of each grant is eight years provided the three common share price targets are met within a defined time period. The options vest 20% per year over five years, starting on the first anniversary of the grant date and must meet the first common share price target to receive any options. PBSOs are granted on an infrequent basis and provided the eligible NEO the opportunity to acquire one Enbridge common share for each option held when the specified term and performance criteria are met. During 2012, Messrs. Monaco, Wuori and Zupan received grants of Enbridge performance stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The common share price targets for the 2012 PSOP are $48.00 CAD, $53.00 CAD and $58.00 CAD, which must be met by February 2019 and will have weighted vesting at a 40%, 40% and 20% based on each target price met. The exercise price of the PBSOs at the time of grant was $39.34 CAD which has been converted into USD using an exchange rate of $0.9891 = $1 USD, representing the noon buying rate in New York for transfers of CAD on the grant date of August 15, 2012.

The amounts included as the grant date fair value for the 2012 PBSO awards represent the amount determined by computing the fair value of the options under ASC 718 on the grant date using the Bloomberg barrier option valuation model with the following CAD assumptions:

- 8 years expected term;
- 16.10% expected volatility;
- 2.80% expected dividend yield; and
- 1.60% risk free interest rate

The fair value of options granted as computed using these assumptions is $4.25 CAD which has been converted to USD using an exchange rate of $0.9891 CAD = $1 USD, representing the noon buying rate in New York for transfers of CAD on the grant date of August 15, 2012, which equates to a grant date fair value of $4.30 USD per option granted. The grant date fair value is expensed over the shorter of the vesting period for the options (generally five years) and the period to early retirement eligibility.

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)] ($) (e)	Option Expiration Date[(1)] (f)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[(4)] (#) (i)	Equity Incentive Plan Awards: Market or Payout of Value Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
Terrance L. McGill	—	68,050	38.65	2-Mar-22	5,094	441,328
	21,300	63,900	28.99	14-Feb-21	6,579	570,030
	24,500	24,500	21.97	16-Feb-20		
	74,250	24,750	15.80	25-Feb-19		
	99,000	—	20.17	19-Feb-18		
Mark A. Maki	—	61,650	38.65	2-Mar-22	4,579	396,749
	19,100	57,300	28.99	14-Feb-21	6,367	551,642
	17,000	17,000	21.97	16-Feb-20		
	30,650	15,050	15.80	25-Feb-19		
	5,200	—	20.17	19-Feb-18		
Stephen J. Neyland	—	39,100	38.65	2-Mar-22	3,705	320,966
	—	33,450	28.99	14-Feb-21	3,396	294,209
	—	7,700	21.97	16-Feb-20		
	—	7,750	15.80	25-Feb-19		
Stephen J. Wuori	—	117,300	38.77	2-Mar-22	17,286	1,494,912
	25,000	75,000	29.11	14-Feb-21	14,854	1,284,520
	—	617,600	39.77	15-Aug-20		
	40,000	40,000	22.34	16-Feb-20		
	90,000	30,000	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		
	660,000	—	17.02	15-Aug-15		
	91,600	—	12.75	3-Feb-15		
	78,000	—	9.65	4-Feb-14		
Leon A. Zupan	—	82,850	38.77	2-Mar-22	5,299	458,262
	27,150	81,450	29.11	14-Feb-21	6,790	587,209
	—	169,400	39.77	15-Aug-20		
	16,700	16,700	22.34	16-Feb-20		
	34,800	11,600	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		
Arthur D. Meyer	—	88,800	38.77	2-Mar-22	5,659	489,406
	28,800	86,400	29.11	14-Feb-21	7,427	642,260
	37,200	37,200	22.34	16-Feb-20		
	77,550	25,850	15.78	25-Feb-19		
	103,400	—	19.90	19-Feb-18		
	32,800	—	16.30	9-Feb-17		
	19,600	—	15.79	13-Feb-16		
	20,000	—	12.75	3-Feb-15		
	40,000	—	9.65	4-Feb-14		
Al Monaco	—	147,500	38.77	2-Mar-22	21,814	1,886,437
	25,000	75,000	29.11	14-Feb-21	14,854	1,284,520
	—	1,058,800	39.77	15-Aug-20		
	40,000	40,000	22.34	16-Feb-20		
	75,000	25,000	15.78	25-Feb-19		
	90,000	—	19.90	19-Feb-18		
	28,400	—	16.30	9-Feb-17		
	32,600	—	15.79	13-Feb-16		
	400,000	100,000	17.02	15-Aug-15		
	37,600	—	12.75	3-Feb-15		
	54,800	—	9.65	4-Feb-14		

(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 September 15, 2002, August 15, 2007, February 19, 2008 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. The PBSOs granted September 16, 2002, became exercisable, as to 50 % of the grant, when the price of an Enbridge common share exceeded $30.50 for 20 consecutive days during the period September 16, 2002 to September 16, 2007, and became exercisable as to 100 % when the price of an Enbridge common share exceeded $35.50 for 20 consecutive days during the same period. As a result of achieving the established performance criteria, the initial five year term of the options was extended to 12 years expiring on August 15, 2015. Upon the performance hurdles being met, the PBSOs are also time vested 20% annually over five years. As of December 31, 2012, both common share price targets for the PBSOs granted August 15, 2007 and February 19, 2008 were met, therefore 100% of the 2007 grant and 80% of the 2008 grant were vested or exercisable and 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 PBSOs issued during 2006 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 2007, ISOs and PBSOs granted to NEOs domiciled in the United States are denominated in USD while those NEOs domiciled in Canada are denominated in CAD. The ISOs and PBSOs 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 6, 2003	10.4125	0.6572	6.8431
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

(4) The unearned common shares, units or other rights that have not vested under stock awards represent PSUs for which the performance criteria discussed in Footnote 3 of the *Grants of Plan-Based Awards* table have not been achieved. The PSUs become vested upon achieving the established performance criteria. The amounts represented in the column are the number of units that have not vested at the closing common share price of one Enbridge common share on the NYSE at $43.32 per share or the TSX at $43.02 per common share converted to USD of $43.24 per share at the conversion rate of $0.9949 CAD = $1 USD representing the weighted average noon rate for 20 trading days immediately preceding the performance period that began on January 1, 2012. The market or payout values presented assume a performance multiplier of 2.0 for PSUs granted in 2012, 2011 and 2010, which amounts represent the maximum level attainable based on forecasts of performance at December 31, 2012.

OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting[(1)(2)] (#) (d)	Value Realized on Vesting[(1)(3)] ($) (e)
Terrance L. McGill	111,400	2,369,166	9,224	777,888
Mark A. Maki	70,000	1,409,664	6,588	555,634
Stephen J. Neyland	34,350	710,602	1,977	77,846
Stephen J. Wuori	160,000	4,434,120	53,766	4,521,388
Leon A. Zupan	82,800	2,250,794	5,047	424,457
Arthur D. Meyer	42,000	1,267,838	12,509	1,051,915
Al Monaco	—	—	53,766	4,521,388

(1) For Mr. Neyland, the number of common shares acquired on vesting for stock awards represents the number of RSUs issued in 2009 increased by the number of additional units obtained from reinvesting dividends received. The value realized on vesting is determined based on the weighted average price of Enbridge stock for 20 trading days prior to the end of the term on December 1, 2012, which was $39.39 USD.

(2) The number of common shares acquired on vesting for stock awards represents the number of PSUs issued in 2010 and the related dividends paid that were used to acquire additional PSUs, all of which matured on December 31, 2012. 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 2010 is expected to occur on or about March 15, 2013.

(3) The value realized on vesting is determined based on the final value of an Enbridge common share of $42.17 USD for the NEOs domiciled in the U.S. or $41.61 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 exchange rate of $0.9897 CAD = $1USD for the PSUs that matured on December 31, 2012.

Pension Plan

Enbridge sponsors two basic 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 cash balance 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 Pension Plans are based on the employees' years of service and final average remuneration with an offset for Social Security benefits, while cash balance benefits are based on annual payout and interest credits to notional member accounts. Defined pension benefits are partially indexed to inflation after a named executive officer's retirement.

For service prior to January 1, 2000, the Pension Plans provide a yearly pension payable in the normal form (60% joint and last 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. For Mr. Wuori and Mr. Meyer, the average salary also includes the highest three pensionable bonuses out of the last five years of continuous service, represented by the greater of 50% of the actual bonus paid or the lesser of the actual or target bonuses. 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 three years prior to January 1, 2000, Mr. Monaco elected to participate in the defined contribution option of the EI RPP. Mr. Monaco will receive a benefit at retirement associated with his participation in the defined contribution option of the EI RPP equal to the amounts contributed on his behalf and the earnings attributed to such amounts.

For service after December 31, 1999, the Pension Plans provide for senior management employees, including the NEOs, a yearly pension payable in the normal form (60% joint and last survivor) equal to: (a) 2% of the sum of (i) the average of the participant's highest annual base salary during three consecutive years out of the last ten years of credited service and (ii) the average of the participant's three highest annual performance bonus periods, represented in each period by 50% of the actual bonus paid, in respect of the last five years of credited service, multiplied by (b) the number of credited years of service. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Plan are indexed at 50% of the annual increase in the consumer price index. For Mr. Neyland, QPP service after December 31, 2001 but prior to becoming a senior management employee includes 2.5 years of cash balance service, with annual pay credits based on his age and service with Enbridge.

Plan benefits that exceed maximum pension rules applicable to qualified plan benefits are paid from the EI SPP and US SPP. Other trusteed pension plans, with varying contribution formulae and benefits, cover the balance of employees.

Mr. Monaco accumulates pension credits equal to 2.5% for each year of service from January 1, 2008 to December 31, 2013.

The table below illustrates the total annual pension entitlements at December 31, 2012 assuming the eligibility requirements for an unreduced pension have been satisfied. We have converted pensions payable in CAD into USD at the rate of $0.9949 CAD = $1.00 USD, the exchange rate at December 31, 2012. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	3.80% at year end 2012
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 nonannuitant tables (UP-1994 with generational mortality improvements)

(1) This is age 60 for all executives except for Messrs. Wuori and Maki, who are eligible for an unreduced pension at age 55.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)
Terrance L. McGill	US QPP	10.50	207,000
	US SPP	10.83	1,723,000
Mark A. Maki	EI RPP	1.92	90,000
	EI SPP	1.92	181,000
	US QPP	24.40	1,666,000
	US SPP	24.40	1,243,000
Stephen J. Neyland	US QPP	10.50	158,000
	US SPP	8.00	405,000
Stephen J. Wuori	EI RPP	18.67	1,111,000
	EI SPP	18.67	10,331,000
	US QPP	13.83	362,000
	US SPP	13.83	99,000
Leon A. Zupan	EI RPP	25.08	1,217,000
	EI SPP	25.08	1,894,000
	US QPP	0.50	35,000
	US SPP	0.50	43,000
Arthur D. Meyer	EI RPP	23.42	1,089,000
	EI SPP	23.42	2,437,000
Al Monaco	EI RPP(1)	17.08	633,000
	EI SPP	14.08	3,678,000

(1) Mr. Monaco's EI RPP Service includes three years spent in defined contribution component of the Pension Plan. The current defined contribution balance has been included in the EI RPP accumulated benefit.

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, Leon A. Zupan, Director and Executive Vice President—Gas Pipelines of Enbridge Management and our General Partner, Al Monaco, Former Director and Former President, Gas Pipelines, Green Energy and International of Enbridge Management and our General Partner and with Arthur D. Meyer, Senior Vice President—Liquids Pipelines. The agreements for Mr. Wuori were entered into effective April 14, 2003 and were amended effective June 24, 2004. On March 10, 2009, Mr. Monaco executed an employment agreement with Enbridge. Prior to that date, Mr. Monaco did not have an employment agreement with us or any Enbridge affiliate. On August 1, 2012, Mr. Zupan executed an employment agreement with Enbridge. Mr. Meyer executed an employment agreement with Enbridge on August 11, 1998. 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. As stated in the opening remarks of Item 11. *Executive Compensation*, Mr. Monaco resigned as a Director of Enbridge Management and our General Partner in October 2012 when he became President of Enbridge and his 2009 employment agreement was terminated and he entered into a new agreement reflective of his new position. The tables below reflect the changes as a result of the new agreement. Messrs. McGill, Maki and Neyland 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, Monaco, Zupan, and Meyer as set forth in the table below, except as noted below in respect of Mr. Monaco's terminated 2009 employment agreement, if such executive officer's employment is terminated: (1) involuntarily without cause or because of the disability of such executive officer; (2) on the election of such executive officer within 90 days following a constructive termination; (3) on the election of such executive officer within 90 days following the one-year anniversary of a change in control of Enbridge, other than certain types of changes of control initiated by management or the board of directors of Enbridge; and (4) by Enbridge within one-year of certain types of changes of control of Enbridge, which change of control is initiated by management or the board of directors of Enbridge. Mr. Monaco's employment agreement did not contain the "single trigger" voluntary termination right following a change of control. Since 2007, it has been Enbridge's policy not to enter into employment agreements granting "single trigger" voluntary termination rights in favor of the executive. The agreements with the other executives were entered into prior to that time.

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 for current year is pro-rated based on retirement date.	Incentive stock options continue to vest. Vested options can be exercised up to three years from retirement or until the stock option term expires (whichever is sooner). Conditions for performance stock options are mentioned below.	Post retirement benefits begin.	Credited service no longer earned.
Involuntary Termination (Not for Cause)	Base salary is paid out in a lump sum: • three years for Chief Executive Officer; and • two years for other executives	Two times (three times for the Chief Executive Officer) the average of short-term incentive awards received during the past two years plus the current year's short-term incentive prorated based on service prior to the termination of employment.[1]	Vested stock options are exercisable in accordance with their terms.[2] Unvested options continue to vest and vested options can be exercised up to 30 days after the notice period expires or until the option term expires (whichever is sooner).	Benefits value is paid out in a lump sum over two years (three years for the Chief Executive Officer).	Two additional years (three years for the Chief Executive Officer) of pension accrual added to final pension calculation.

Type of Termination	Base Pay	Short-term Incentive	Long-term Incentive	Benefits	Pension
Termination (Constructive Dismissal)			All options are cancelled on the date of termination.		
Termination (Change of Control)			All stock options vest. All performance stock units mature and value is assessed and paid based upon performance measures achieved to that time.		

(1) For Mr. Monaco, pro-rated payment for current year is based upon the prior year's short term incentive award.

(2) Performance stock options are valued assuming all performance measures have been met.

Performance stock options have the same termination provisions as incentive stock options except:

- For retirement, we prorate their performance stock options for the period of active employment in the 5 year period starting January 1 of the year of grant. They can exercise these options until the later of three years after retirement or 30 days after the share price targets must be met (or up to the date the option expires, whichever is earlier), as long as the performance criteria are met;
- For death, unvested options are pro-rated and the plan assumes performance requirements have been met;
- For involuntary termination (not for cause), unvested options are pro-rated; and
- For change of control, the plan assumes the performance requirements have been met.

We pro-rate based on active employment during the vesting period (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.

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 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.

Each of Messrs. Wuori, Meyer, Zupan, and Monaco is 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 either Messrs. Zupan or Meyer, Enbridge would owe incremental benefits with a value of approximately \$6 million for each while Enbridge would owe \$19 million or \$13 million for Mr. Monaco and Mr. Wuori, respectively. Such amounts assume that termination was effective as of December 31, 2012, 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, Zupan, Meyer and Monaco 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 July 30, 2012, Martha O. Hesse retired as chairman and as of August 14, 2012, retired as a member of the boards of directors of Enbridge Management and our General Partner. In addition, Rebecca B.

Roberts was elected to the boards of directors of Enbridge Management and our General Partner effective July 30, 2012. On October 1, 2012, Al Monaco resigned as a member of the boards of directors of Enbridge Management and our General Partner with J. Richard Bird subsequently appointed to replace Mr. Monaco.

On December 5, 2011, the boards of directors amended the Director Compensation Plan effective January 1, 2012, under which the directors shall receive an annual retainer of $115,000, which was increased from $95,000, with no additional fees for attending regular meetings. Furthermore, the annual retainer paid to the Chairman of the Board was increased to $20,000 from $15,000 and the annual retainer paid to the Chairman of the Audit Committee was increased to $15,000 from $10,000. The out-of-state travel fee remained at $1,500 per the 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. In addition, on December 5, 2011, the Director Compensation Plan was amended to increase 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. Consistent with 2011, each member of the Special Committee receives $1,500 per meeting.

DIRECTOR COMPENSATION

Name (a)	Fees Earned or Paid in Cash ($) (b)
Jeffrey A. Connelly *Chairman of the Board*	204,860
J. Herbert England *Audit Committee Chairman*	164,331
Dan A. Westbrook	178,250
Rebecca B. Roberts[1]	92,285
Martha O. Hesse[2]	96,375

(1) Ms. Roberts was elected as a director in July 2012, thus the fees present above are from July 30, 2012 thru December 31, 2012.

(2) Ms. Hesse retired in August 2012, thus the fees present above are from January 1, 2012 thru August 14, 2012.

The General Partner indemnifies each director for actions associated with being a director to the fullest extent permitted under Delaware law and maintains errors and omissions insurance.

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 and Director
(Principal Executive Officer)

/s/ Terrance L. McGill

Terrance L. McGill
President of General Partner and
Director

/s/ Stephen J. Wuori

Stephen J. Wuori
Executive Vice President—Liquids
Pipelines and Director

/s/ Leon A. Zupan

Leon A. Zupan
Executive Vice President—Gas
Pipelines and Director

/s/ J. Richard Bird

J. Richard Bird
Director

/s/ Jeffrey A. Connelly

Jeffrey A. Connelly
Director

/s/ J. Herbert England

J. Herbert England
Director

/s/ Rebecca B. Roberts

Rebecca B. Roberts
Director

/s/ Dan A. Westbrook

Dan A. Westbrook
Director

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information as of February 14, 2013 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. 1100 Louisiana St., Suite 3300 Houston, TX 77002	i-units	41,198,424	100.0
Enbridge Energy Company, Inc. 1100 Louisiana St., Suite 3300 Houston, TX 77002	Class A common units Class B common units	46,518,336 7,825,500	18.3 100.0

We do not have any shares that have been approved for issuance under an equity compensation plan.

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 14, 2013 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 Partners, L.P.			Enbridge Energy Management, L.L.C.		
Name	**Title of Class**	**Amount and Nature of Beneficial Ownership[1]**	**Percent of Class**	**Title of Class**	**Number of Shares[1]**	**Percent of Class**
Jeffrey A. Connelly[2]	Class A common units	20,000	*	Listed Shares	—	—
J. Herbert England	Class A common units	7,876	*	Listed Shares	—	—
Rebecca B. Roberts	Class A common units	4,000	*	Listed Shares	—	—
Dan A. Westbrook[3]	Class A common units	21,000	*	Listed Shares	—	—
J. Richard Bird[4]	Class A common units	—	—	Listed Shares	81,741	*
Mark A. Maki[8]	Class A common units	4,000	*	Listed Shares	2,457	*
Terrance L. McGill	Class A common units	8,000	*	Listed Shares	4,319	*
Stephen J. Wuori	Class A common units	—	—	Listed Shares	—	—
Leon A. Zupan	Class A common units	—	—	Listed Shares	—	—
Martha O. Hesse[5]	Class A common units	—	—	Listed Shares	53,434	*
Al Monaco	Class A common units	—	—	Listed Shares	—	—
Arthur D. Meyer	Class A common units	—	—	Listed Shares	—	—
Richard L. Adams	Class A common units	—	—	Listed Shares	—	—
Janet L. Coy[6]	Class A common units	500	*	Listed Shares	—	—
E. Chris Kaitson	Class A common units	—	—	Listed Shares	—	—
John A. Loiacono	Class A common units	5,000	*	Listed Shares	—	—
Susan E. Miller	Class A common units	—	—	Listed Shares	—	—
Byron C. Neiles	Class A common units	—	—	Listed Shares	—	—
Stephen J. Neyland[7]	Class A common units	—	—	Listed Shares	3,044	*
Kerry C. Puckett	Class A common units	3,000	*	Listed Shares	1,087	*
William M. Ramos	Class A common units	—	—	Listed Shares	—	—
Allan M. Schneider	Class A common units	—	—	Listed Shares	—	—
Bruce A. Stevenson	Class A common units	—	—	Listed Shares	—	—
David K. Wudrick	Class A common units	—	—	Listed Shares	—	—
Darren Yaworsky	Class A common units	—	—	Listed Shares	—	—
All Officers, directors and nominees as a group (25 persons)	Class A common units	73,376	*	Listed Shares	146,082	*

* 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 21,000 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 5,000 Class A common units are held by the Mary Ruth Westbrook Trust, for which Mr. Westbrook is the sole trustee and beneficiary.

(4) The 81,741 Listed Shares owned by Mr. Bird are held by an investment holding corporation over which he exercises full control and direction.

(5) The 53,434 Listed Shares beneficially owned by Ms. Hesse are held in an Individual Retirement Account established for her benefit. Ms. Hesse retired as a director of our General Partner and Enbridge Management on August 14, 2012.

(6) The 500 Class A common units beneficially owned by Ms. Coy are held in an Individual Retirement Account established for her benefit.

(7) The 3,044 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.

(8) 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.

Item 13. Certain Relationships and Related Transactions, and Director Independence

INTEREST OF THE GENERAL PARTNER IN THE PARTNERSHIP

At December 31, 2012, our General Partner had the following ownership interests in us:

	Quantity	Effective Ownership %
Direct ownership		
Class A common units representing limited partner interest	46,518,336	15.1%
Class B common units representing limited partner interest	7,825,500	2.5%
General Partner interest	6,188,415	2.0%
Indirect ownership		
Enbridge Management shares (Listed and Voting)	6,936,943	2.2%
Total effective ownership	67,469,194	21.8%

INTEREST OF ENBRIDGE MANAGEMENT IN THE PARTNERSHIP

At December 31, 2012, Enbridge Management owned 41,198,424 i-units, representing a 13.3% 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 2012, we paid cash and incentive distributions to our General Partner for its general partner ownership interest of approximately $122.3 million and cash distributions of $100.1 million and $16.8 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.

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 2012, 2011 and 2010, distributed a total of 2,632,090, 2,420,228 and 2,507,688 i-units to Enbridge Management, on a split-adjusted basis, and retained cash totaling approximately $85.0 million, $75.7 million and $68.3 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 2012, 2011 and 2010, in connection with our various issuances and sales of Class A common units, our General Partner contributed approximately $9.4 million, $18.2 million and $8.6 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.

The total amount we reimbursed the Canadian service providers pursuant to the operational services agreement for the years ended December 31, 2012, 2011 and 2010 was $133.0 million, $97.3 million and $74.5 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, 2012, 2011 and 2010 was $291.1 million, $264.3 million and $231.6 million, respectively.

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of $33.1 million, $24.9 million and $16.3 million during 2012, 2011 and 2010, 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. 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.

Line 6A and 6B Expense Reimbursement

For the years ended December 31, 2012, 2011 and 2010, we have reimbursed Enbridge $4.1 million, $7.6 million and $14.9 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, 2012, 2011 and 2010, are operating revenues of $414.7 million, $354.3 million and $430.4 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 2012, 2011 and 2010 was approximately $0.8 million, $0.8 million and $0.9 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, 2012, 2011 and 2010, are costs for natural gas purchases of $285.4 million, $200.8 million and $242.3 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, 2012, 2011 and 2010 are as follows:

	A1 Term Note (in millions)
Balance at December 31, 2010	$ 347.4
Borrowings	7.0
Repayments	(12.4)
Balance at December 31, 2011	342.0
Borrowings	—
Repayments	(12.0)
Balance at December 31, 2012	$ 330.0

The following table presents in millions, the scheduled maturities of the A1 Term Note based upon the $330.0 million outstanding at December 31, 2012.

	(in millions)
2013	$ 12.0
2014	12.0
2015	12.0
2016	12.0
2017	12.0
Thereafter	270.0
Total	$ 330.0

Our General Partner also made equity contributions totaling $3.3 million and $102.3 to the OLP during the years ended 2011 and 2010, respectively, to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $53.9 million, $53.2 million and $60.6 million to our General Partner for its 66.67% share of the earnings of the Alberta Clipper

Pipeline for the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010, 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)	
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
2010				
October 27	November 12	$ 10.7	$ 21.4	$ 32.1
July 23	August 13	8.6	17.2	25.8
		$ 19.3	$ 38.6	$ 57.9

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. 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 Eastern Access Joint Funding Agreement. Before June 30, 2013, the Partnership has the option to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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 $347.9 million to the OLP for the year ended December 31, 2012, 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 $3.4 million to our General Partner for its 60% ownership of the EA interest for the year ended December 31, 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. 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. We also have an option, exercisable prior to June 30, 2013, for the Partnership to reduce its funding and associated economic interest in the projects by up to 15 percentage points down to 25%. Additionally, 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. All other operations are captured by the LH interests.

Our General Partner has made equity contributions totaling $3.0 million to the OLP for the year ended December 31, 2012, to fund its equity portion of the construction costs associated with the Eastern Access Projects.

Asset Purchase and Sale Transactions with Affiliates

Line 13 Exchange and Lease

In connection with the development of a diluent pipeline being constructed by Enbridge Pipelines (Southern Lights), L.L.C., or Southern Lights, a wholly-owned subsidiary of our General Partner, we completed the transfer of a 156-mile section of pipeline, which we refer to as Line 13, from our Lakehead system to Southern Lights in exchange for a newly constructed pipeline for transporting light sour crude oil. In connection with the exchange, at the request of shippers and to ensure adequate southbound pipeline capacity prior to the completion of the Alberta Clipper Pipeline, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease which became effective February 20, 2009, expired in April 2010 in accordance with the lease. For the year ended December 31, 2010, we paid $5.4 million to Southern Lights to lease Line 13, which we recovered through the tariff that went into effect on April 1, 2010 on our Lakehead system.

The exchange resulted in a $166.5 million increase in “Property, plant and equipment, net” and the capital account of our General Partner included in “Partners’ capital” on our December 31, 2009 consolidated statement of financial position, representing the $171.5 million cost of the light sour pipeline that was in excess of the $5.0 million net book value of the Line 13 assets we exchanged. The costs were transferred to us through the capital account of our General Partner and are included in the $171.5 million. Further, $3.8 million of additional costs for the year ended December 31, 2010 were incurred and transferred by Southern Lights, which increased the total costs for the light sour crude oil pipeline at December 31, 2010 to $175.3 million. The light sour pipeline is newer and has a slightly higher capacity than Line 13, which will allow us to transport additional volumes of light sour crude oil on our Lakehead system with less integrity and maintenance costs, although depreciation and property tax expense is anticipated to increase in future periods due to the higher book value associated with these assets.

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 $122.3 million, $95.0 million and $69.8 million for the years ended December 31, 2012, 2011, and 2010, 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, 2012 and 2011, our General Partner owned 46,518,336 Class A common units, representing a 15.1% and 16.0% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $100.1 million, $97.3 million and $94.1 million for the years ended December 31, 2012, 2011 and 2010, respectively, with respect to its ownership of Class A common units. 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. The conversion became effective upon the determination by our General Partner that the converted Class C units would have, as a substantive matter, like intrinsic economic and United States federal income tax characteristics, in all material respects, to the intrinsic economic and United States federal income tax characteristics of our outstanding Class A common units. Along with the conversion and adjusted for the 2011 split, we issued and sold 42,490 Class A common units to our General Partner for a purchase price of $23.535 per unit, or approximately $1.0 million.

As of December 31, 2012 and 2011, our General Partner also owned 7,825,500 Class B common units, representing a 2.5% and 2.7% limited partner interest in us for the respective years. We paid the General Partner cash distributions of $16.8 million, $16.4 million and $15.8 million for the years ended December 31, 2012, 2011, and 2010, respectively, with respect to its ownership of Class B common units.

As a result of the October 2009 conversion of all our outstanding Class C units into Class A common units, we did not have any Class C units outstanding at December 31, 2012 and 2011.

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.

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 2012, we had the following "related person" transactions (as the term is defined in Item 404 of Regulation S-K):

- An affiliate of Enbridge which 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 2012, she received total cash compensation of $216,518.81 and benefits estimated at approximately 35% of her base compensation for a total of $262,667.89.

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,	
	2012	2011
Audit fees[(1)]	$ 3,894,000	$ 5,131,300
Tax fees[(2)]	775,500	700,000
Total	$ 4,669,500	$ 5,831,300

(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 2012 and 2011 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 118 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, 2012, 2011 and 2010.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2012, 2011 and 2010.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010.

e. Consolidated Statements of Financial Position as of December 31, 2012 and 2011.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2012, 2011 and 2010.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

All schedules have been omitted because they are not applicable, the required information is shown in the consolidated financial statements or Notes thereto or the required information is immaterial.

(3) *Exhibits.*

Reference is made to the "Index of Exhibits" following the signature page on page 245, which is hereby incorporated into this Item.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.,
as delegate of the General Partner

/s/ Mark A. Maki

By: Mark A. Maki
(President)

Date: February 14, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 14, 2013 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ Mark A. Maki
Mark A. Maki
President and Director
(Principal Executive Officer)

/s/ Terrance L. McGill
Terrance L. McGill
President of General Partner and Director

/s/ Stephen J. Wuori
Stephen J. Wuori
Executive Vice President—Liquids Pipelines and Director

/s/ Leon A. Zupan
Leon A. Zupan
Executive Vice President—Gas 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/ William M. Ramos
William M. Ramos
Controller

/s/ Jeffrey A. Connelly
Jeffrey A. Connelly
Director

/s/ J. Herbert England
J. Herbert England
Director

/s/ Rebecca B. Roberts
Rebecca B. Roberts
Director

/s/ Dan A. Westbrook
Dan A. Westbrook
Director

Index of Exhibits

Each exhibit identified below is filed as a part of this annual report. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report pursuant to Item 15(b) of Form 10-K.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of 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).
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).
10.1*+	Executive Employment Agreement, dated December 20, 2012, between Leon Zupan, the Executive, and Enbridge Inc., the company effective August 1, 2012.
10.2*+	Executive Employment Agreement, dated August 11, 1998, between Art D. Meyer, the Executive, and Enbridge Inc.
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).
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).

Exhibit Number	Description
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	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).
10.12	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).
10.13	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).
10.14	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).
10.15	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.16	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).
10.17	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of our Quarterly Report on Form 10-Q, filed on November 14, 2002).
10.18	Credit Agreement, dated December 18, 2007, between the Partnership, as Borrower, and Enbridge (U.S.), Inc., as Lender (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on December 19, 2007).
10.19	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).
10.20	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).
10.21	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).
10.22	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).

Exhibit Number	Description
10.23	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).
10.24	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).
10.25	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).
10.26	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).
10.27	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).
10.28	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).
10.29	Indenture, dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.1 of the Lakehead Pipe Line Company, Limited Partnership Current Report on Form 8-K, filed on October 20, 1998).
10.30	First Supplemental Indenture, dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership Current Report on Form 8-K, filed on October 20, 1998).
10.31	Second Supplemental Indenture, dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.3 of the Lakehead Pipe Line Company, Limited Partnership Current Report on Form 8-K, filed on October 20, 1998).
10.32	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership Current Report on Form 8-K, filed on November 20, 2000).
10.33	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.4 of the Lakehead Pipe Line Company, Limited Partnership Current Report on Form 8-K, filed on October 20, 1998).
10.34+	Executive Employment Agreement, dated April 14, 2003, between Stephen J.J. Letwin, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on May 3, 2006).
10.35+	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).
10.36+	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).

Exhibit Number	Description
10.37+	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).
10.38+	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).
10.39+	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).
10.40*+	Enbridge Performance Stock Option Plan (2007), amended and restated in 2011, further amended November 2012.
10.41+	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).
10.42*+	Enbridge Performance Stock Unit Plan (2007), as amended November 2012.
10.43	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).
10.44	First Supplemental Indenture, dated May 27, 2003, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.6 of our Registration Statement on Form S-4, filed on June 30, 2003).
10.45	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).
10.46	Third Supplemental Indenture, dated January 9, 2004, between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 99.3 of our Current Report on Form 8-K, filed on January 9, 2004).
10.47	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).
10.48	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).
10.49	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).
10.50	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).
10.51	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).
10.52	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).
10.53	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).
10.54	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).
10.55	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).

Exhibit Number	Description
10.56	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).
10.57	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).
10.58	Replacement Capital Covenant, dated September 27, 2007, by Enbridge Energy Partners, L.P. in favor of the debtholders designated therein (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on September 28, 2007).
10.59	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of our Current Report on Form 8-K, filed on February 10, 2005).
10.60	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).
10.61	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).
10.62	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).
10.63	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).
10.64	Amended and Restated Equity Distribution Agreement dated as of May 27, 2011 between the Partnership and UBS Securities LLC (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K, filed on May 27, 2011).
10.65	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).
10.66	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).
10.67	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).
10.68	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).
10.69	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).
10.70*	Allocation Agreement, dated December 31, 2012, by and between Enbridge Inc., the Partnership and Enbridge Income Fund Holdings Inc.
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.

Exhibit Number	Description
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.

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Maki, certify that:

1. I have reviewed this Annual Report on Form 10-K of Enbridge Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 14, 2013

By: /s/ Mark A. Maki

Mark A. Maki
President
(Principal Executive Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. Neyland, certify that:

1. I have reviewed this Annual Report on Form 10-K of Enbridge Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 14, 2013

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President, Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

Exhibit 32.1

CERTIFICATE OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Executive Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2012 (the "Annual Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 14, 2013

By: /s/ Mark A. Maki

Mark A. Maki
President
(Principal Executive Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)

Exhibit 32.2

CERTIFICATE OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Financial Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2012 (the "Annual Report") filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)), as amended, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and that the information contained in the Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: February 14, 2013

By: /s/ Stephen J. Neyland

Stephen J. Neyland
Vice President, Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partner)