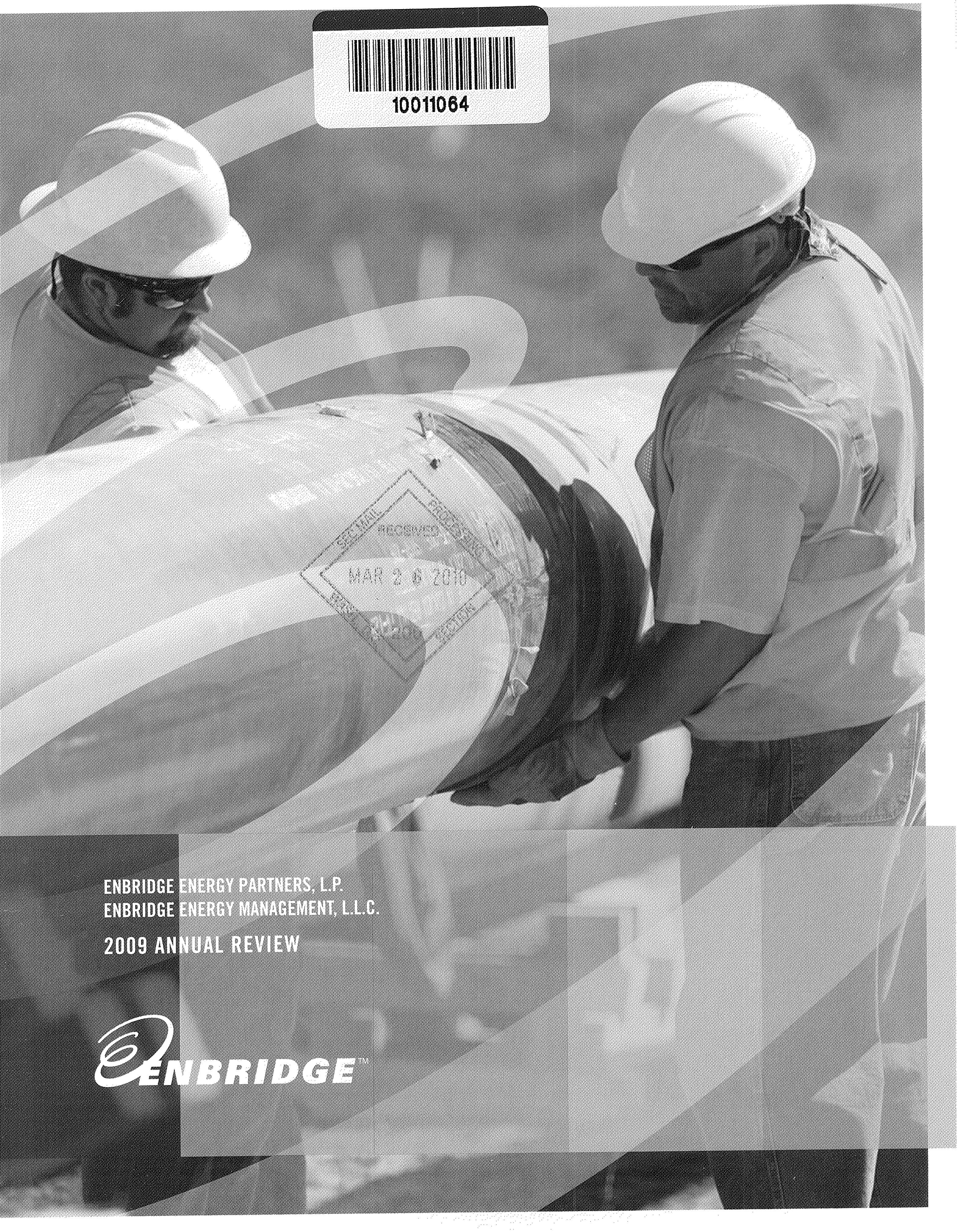


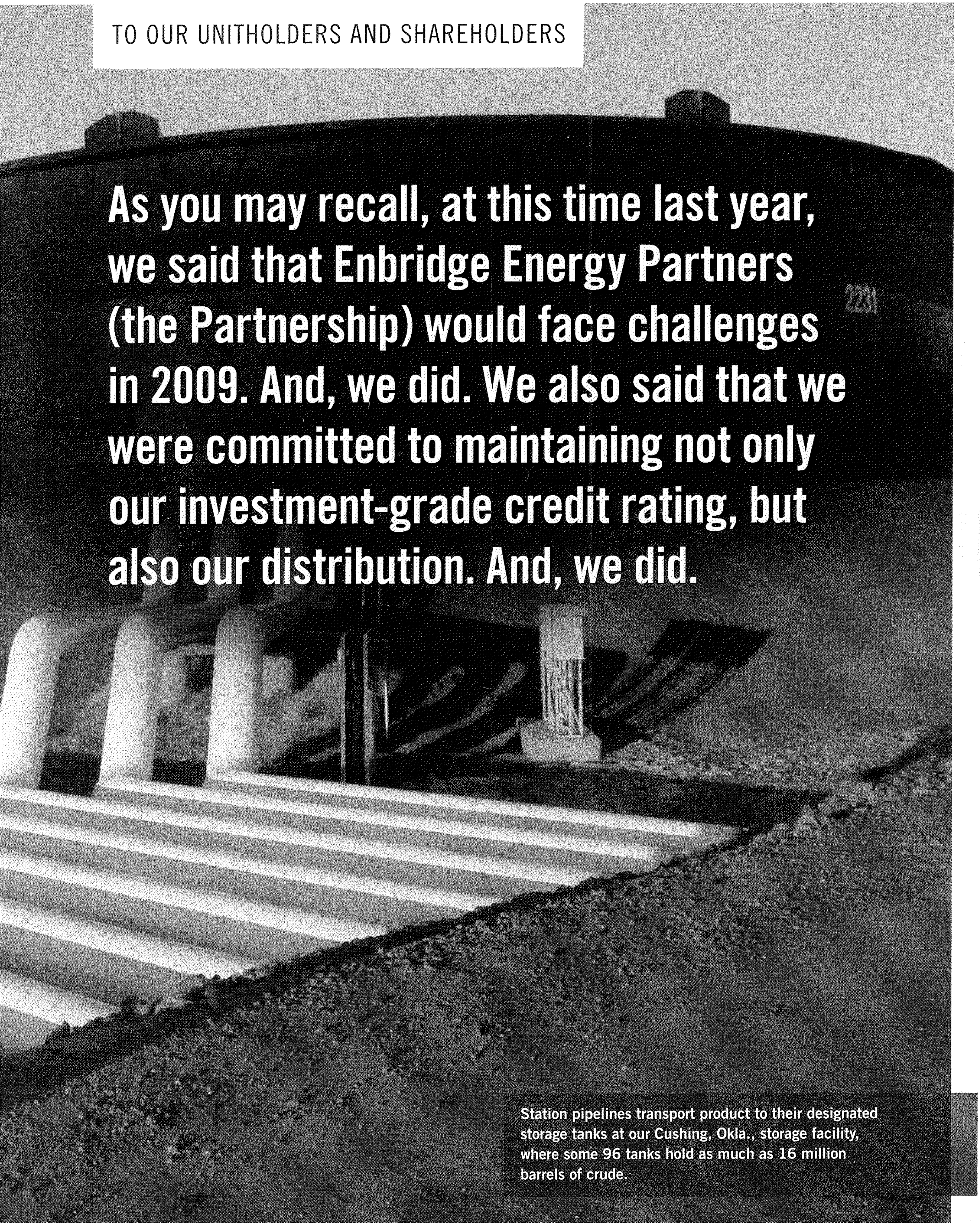
ENBRIDGE ENERGY PARTNERS, L.P.
ENBRIDGE ENERGY MANAGEMENT, L.L.C.

2009 ANNUAL REVIEW

ENBRIDGE™

Our Longview plant in Longview, Texas, is one of 16 treating and processing facilities on our East Texas System.

MAJOR PARTNERSHIP AND AFFILIATED SYSTEMS
LIQUIDS SYSTEMS
EEP Liquids Pipelines
ENB Pipelines and Joint Ventures
EEP Southern Access Expansion
EEP/ENB Alberta Clipper Pipeline
NATURAL GAS SYSTEMS
EEP Natural Gas Pipelines
Fort McMurray
OIL SANDS
Edmonton
Hardisty
Calgary
Regina
Clearbrook
Superior
Toronto
Buffalo
Delavan
Detroit
Chicago
Flanagan
Toledo
Wood River
Patoka
Cushing
ANADARKO BASIN
Dallas
FORT WORTH BASIN
EAST TEXAS BASIN
Houston



As you may recall, at this time last year, we said that Enbridge Energy Partners (the Partnership) would face challenges in 2009. And, we did. We also said that we were committed to maintaining not only our investment-grade credit rating, but also our distribution. And, we did.

Station pipelines transport product to their designated storage tanks at our Cushing, Okla., storage facility, where some 96 tanks hold as much as 16 million barrels of crude.

Despite one of the most challenging economic environments we have seen, 2009 was a very successful year for the Partnership. Through the year, we maintained our quarterly distribution at $0.99 per unit and our distribution coverage ratio remained healthy, ending with coverage of 1.11 times.

We enhanced our liquidity position, stabilized our credit ratings and addressed our financing needs by entering into a joint-funding agreement for the Alberta Clipper project. We sold non-core natural gas pipeline assets and limited our capital expenditures to those projects that were most strategic. We implemented significant cost saving measures throughout 2009 and made significant progress on our expansion program. We did all the things we said we were going to do in 2009 and were able to deliver adjusted net income results that were 18 percent higher than our expectations at the beginning of the year. The unit price for the Partnership was up 111 percent for 2009, and the three-year shareholder return was 40 percent for the Partnership versus 31 percent for our peers.

On the project front, we completed the 400,000 barrels per day (Bpd) Southern Access Expansion Stage II. In January, 2010 we placed in-service the North Dakota Expansion Phase VI, which added 51,000 Bpd of additional capacity to our North Dakota System. The U.S. portion of Alberta Clipper was approximately 90 percent complete as of January 2010, with construction of the Canadian portion of the Alberta Clipper expansion mechanically complete. We expect that Alberta Clipper will be completed and available for line-fill on April 1, 2010, three months ahead of schedule. This will add significant earnings and cash flow to the Partnership.

Financially, we had a solid year in 2009. Adjusted operating income from the Liquids business was $443.7 million, an increase of $101.5 million from 2008. In our Natural Gas business, adjusted operating income was $154.2 million, a decrease of $16.7 million from 2008. The Partnership adjusted net income for the year was $377.1 million, 6 percent higher than 2008. Adjusted EBITDA was 15 percent higher than 2008.

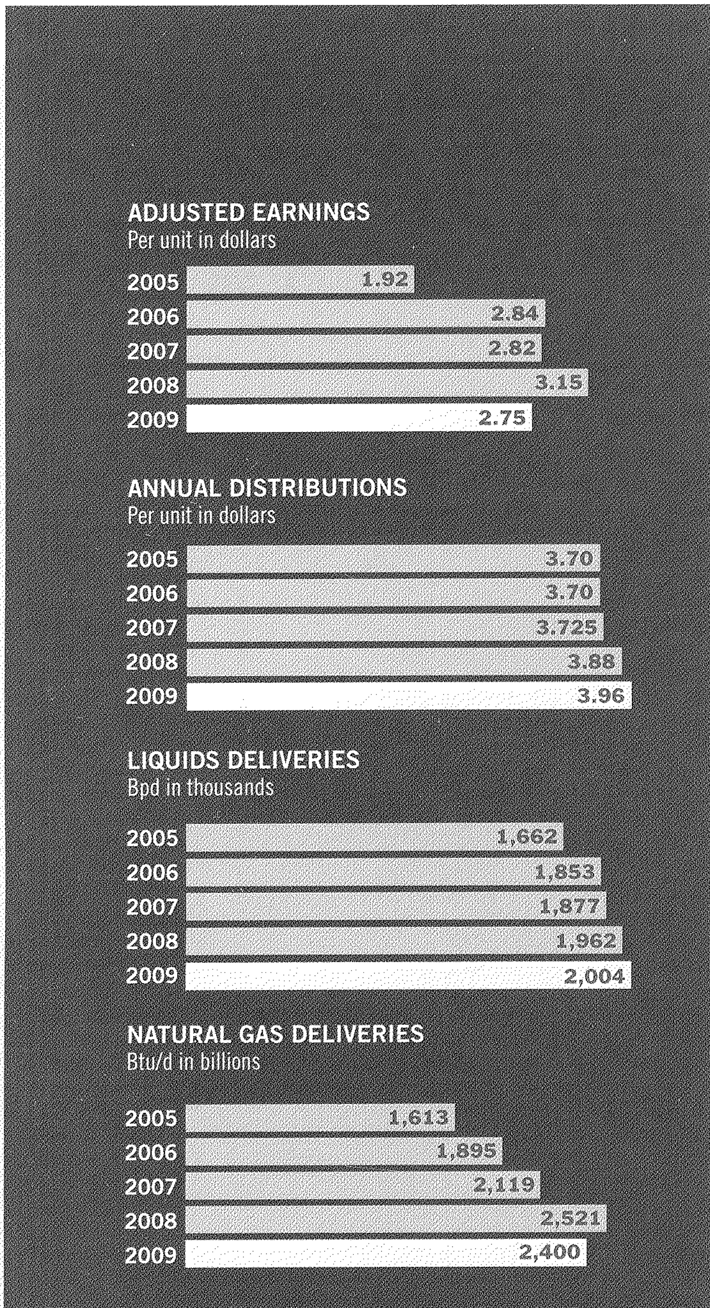
What's ahead? Our multi-year, multi-billion-dollar expansion program is largely complete. However, we believe solid, long-term fundamentals in both crude oil and natural gas will result in more infrastructure needs; we are well positioned to pursue growth opportunities in both lines of business. We do not expect that major expansions to our Lakehead System will be required over the next few years. We do, however, see significant growth potential in our North Dakota System, where the Bakken Shale is located. Production in the Bakken, one of the most promising production areas, is expected to quickly ramp-up over the next few years to about 350,000 Bpd. As the full potential of the play is developed, volumes could well exceed that number. The Partnership is well positioned to capitalize on that growth by providing additional capacity on our North Dakota System, which supplies the Lakehead System and the North Dakota refining market.

Our Cushing crude oil storage facilities are attracting significant interest from third parties looking for contract storage capacity. Currently, we have close to 16 million barrels of storage capacity with additional expansions possible.

With respect to natural gas, we continue to see significant growth potential in areas such as the Haynesville Shale and the Anadarko Granite Wash as well as areas where we don't currently operate such as the Marcellus Shale

Steve Letwin
Managing Director

Terry McGill
President



located in the eastern United States. Early estimates have calculated that the Marcellus Shale contains between an estimated 1.9 - 500 trillion cubic feet (Tcf) of natural gas. Even if only 10 percent of that gas is recovered, it would be enough to supply the entire U.S. for about two years. As such, we are closely monitoring potential development opportunities in areas such as the Marcellus Shale, where we can replicate the success we have had with our gathering and processing businesses in Texas.

Though volumes decreased on our natural gas systems in 2009, we expect this trend to change in 2010 as rig counts stabilize and horizontal drilling technology enhances well productivity. We are working on several growth initiatives that would add capacity and volumes to our East Texas System in the South Haynesville area of Shelby County, Texas.

While 2009 results were solid and the economic environment is improving, we recognize that we will continue to operate under a challenging environment in 2010. The Partnership's strong competitive position in both liquids and natural gas provides significant upside potential. We are fortunate to have a strong general partner in Enbridge Inc. and a smart, dedicated workforce.

Our commitment to the environment and our people remains strong. One area we always strive to improve is safety both for our employees and our neighbors around our facilities. We are committed to providing safe, reliable and environmentally responsible energy transportation options.

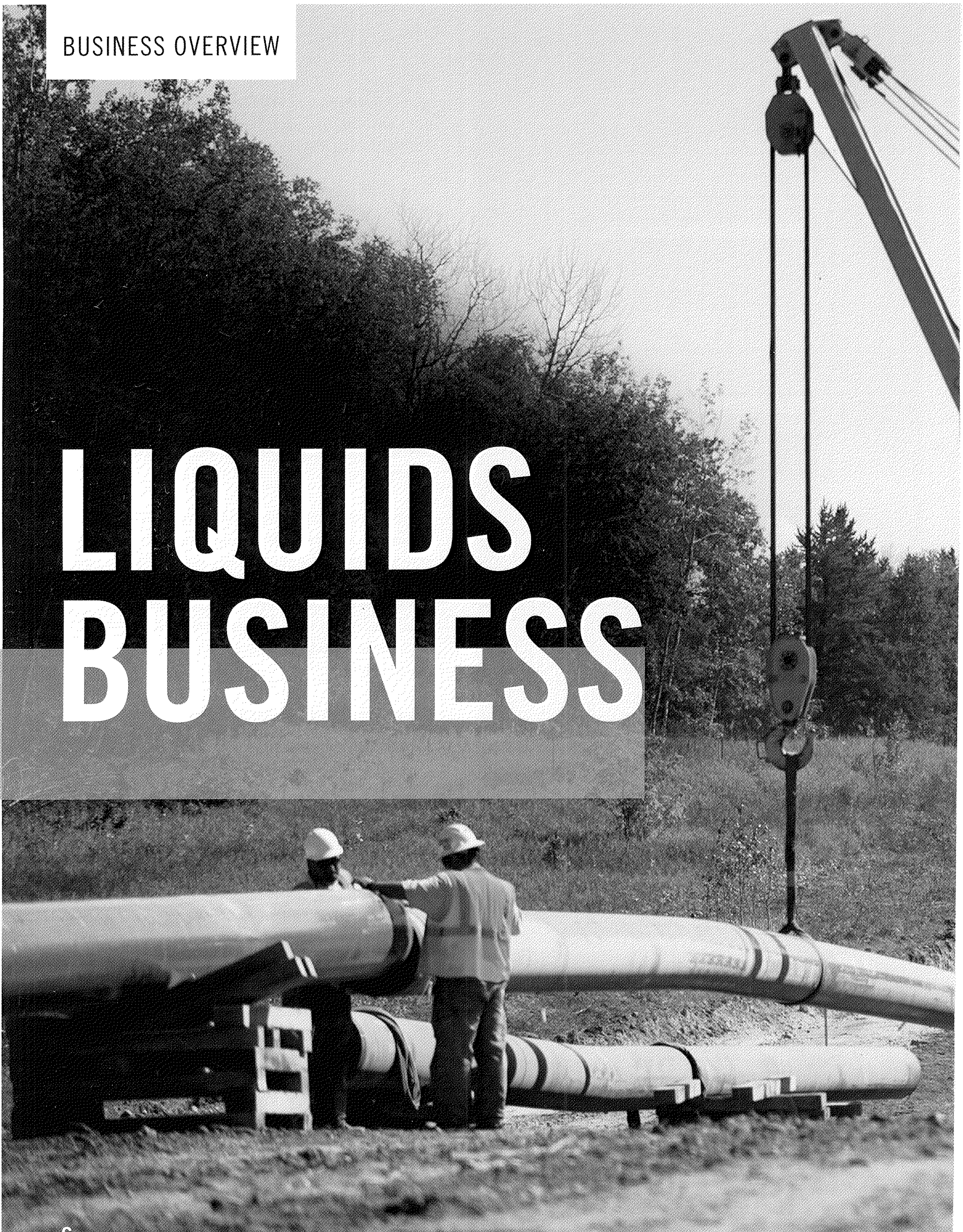
We are deeply saddened by the deaths of two Enbridge employees; the first fatality occurred during a hydrogen sulfide release at our gas treating plant near Bryans Mill, Texas, and the second, a traffic fatality in the Texas Panhandle. We strive every day to achieve a zero-tolerance safety record and work diligently to meet that goal. These incidents reinforce our focus on safety in 2010 and beyond.

We are in a much better financial position going into 2010 and will continue to work diligently to ensure long-term stability of our distribution. Our pledge to you is that we will continue to pursue growth opportunities that are accretive to our unitholders while maintaining our commitment to our sustainable business model that provides safe and reliable transportation services to our customers.

Stephen J. J. Letwin
Managing Director
Enbridge Energy Company, Inc.
February 19, 2010

Terrance L. McGill
President
Enbridge Energy Company, Inc.
February 19, 2010

LIQUIDS BUSINESS



Our Liquids business accounted for $462.0 million of operating income for the year ended December 31, 2009, representing an increase of $119.8 million over the same period in 2008. The favorable results are primarily attributable to transportation rate increases that went into effect during 2009, partially offset by higher operating and administrative costs and depreciation.

Pipeline crew members align joints of the Alberta Clipper pipeline near Rosby, Minn. Construction of the 326-mile Alberta Clipper pipeline began in August 2009 and is on track to wrap up by April 2010, three months ahead of schedule.

LAKEHEAD SYSTEM

We celebrated the 60th anniversary of our Lakehead System in 2009. The first pipeline in the Lakehead System was constructed in 1949, and as of 2010, the U.S. right-of-way will have been expanded to include up to six separate and parallel crude oil and liquid petroleum pipelines. Not only is the Lakehead System a common carrier pipeline that serves as the primary transporter of crude oil and liquid petroleum to the United States from western Canada, but it also supplies the major refining markets in the U.S. Great Lakes and upper Midwest as well as in Ontario, Canada. When combined with the Enbridge Inc. mainline system in Canada, it is the longest liquid petroleum pipeline system in the world. In addition, Enbridge Inc.'s newly expanded Spearhead Pipeline connects with the Lakehead System near Chicago and offers crude oil shippers increased access to the Mid-Continent and Gulf Coast markets through the Cushing, Okla., Hub.

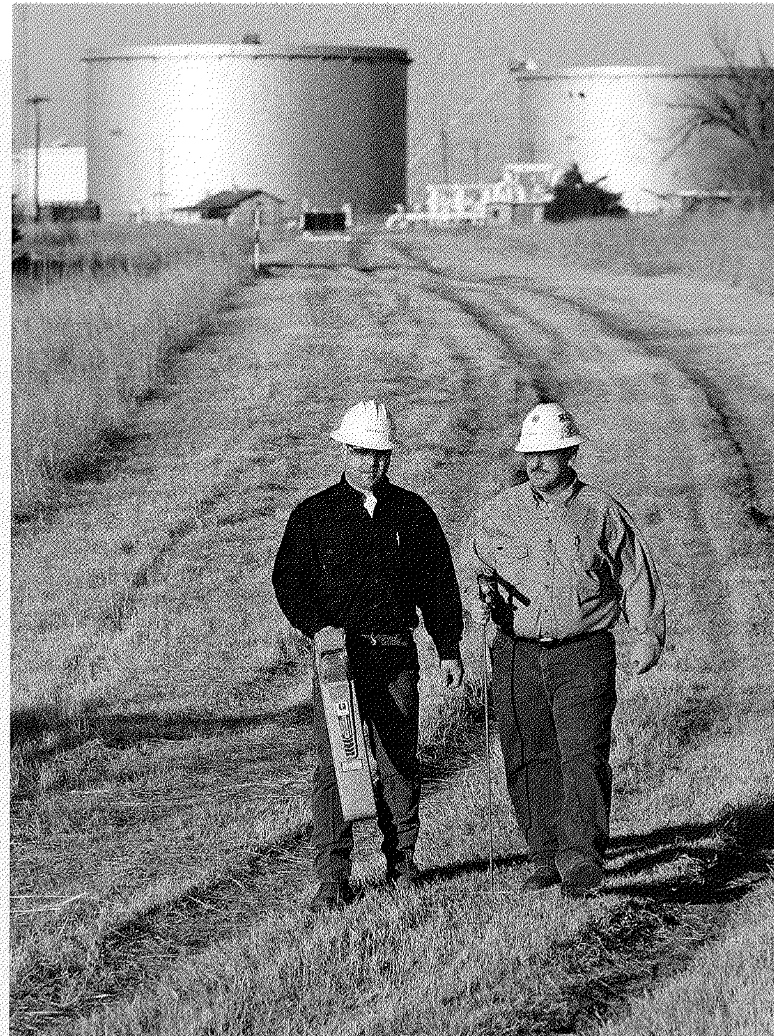
In 2009, average system deliveries on the Lakehead System increased by 1.9 percent, from the same period in 2008 and contributed an additional $9.5 million to operating revenue. Deliveries on the Lakehead System in 2009 averaged 1.65 million Bpd compared with 1.62 million Bpd in 2008. The increase is attributed to increases in crude oil supplies from the continued development of the Alberta oil sands.

Canada continues to be the largest source of U.S. crude oil imports by supplying about 1.2 million Bpd of the U.S. crude oil imports. Approximately 68 percent of western Canadian crude oil exports to the United States in 2009 were shipped via the Lakehead System. Of the total Lakehead System receipts, some 5 percent are sourced from domestic production, including increasing deliveries from our North Dakota System.

Crude oil price volatility in 2008 and 2009 caused some producers to cancel or defer projects. This is likely to slow the demand for additional capacity on our Lakehead mainline system in the short-term, but the Canadian Association of Petroleum Producers (CAPP) is forecasting future production from the Alberta oil sands to grow steadily during the next 10 years with an additional 1.4 million Bpd of incremental supply available by 2019.

MID-CONTINENT SYSTEM

Our Mid-Continent System consists of 480 miles of pipeline and includes the Ozark and West Tulsa Pipelines.



Operations technicians Greg Bowman, left, and Marty Gaunder, right, head out past Cushing's tanks to perform a maintenance check on the pipelines.

The Ozark Pipeline transports crude oil from Cushing to Wood River, Ill., serving refineries in the U.S. Mid-Continent region. In addition, there are 96 storage tanks, ranging in size from 55,000 to 575,000 barrels, at our Cushing and El Dorado, Kan., terminals with a total capacity of 15.9 million barrels. In 2009, the Mid-Continent System recorded average deliveries of 238,000 Bpd. In early 2009, Enbridge Inc. completed a 68,300 Bpd expansion of its Spearhead Pipeline to a capacity of approximately 193,300 Bpd. The Spearhead Pipeline interconnects with our Lakehead System.

NORTH DAKOTA SYSTEM

The Partnership's North Dakota System continues to provide a vital transportation route for producers in eastern Montana, North Dakota and southern Saskatchewan seeking to transport growing, market-constrained supplies of crude oil sourced from the Bakken Play to refineries in the U.S. Midwest and beyond through deliveries into

ENBRIDGE

Check out Tax Web on enbridgepartners.com

Don't wait for your K-1 to arrive by the U.S. Postal Service!

As an Enbridge Energy Partners unitholder you can:

- View your tax schedules for the current year.
- Print your tax package, including instructions.
- Automatically transfer amounts from your Schedule K-1 to IRS forms filed by individuals.
- Download your K-1 information into TurboTax software.
- Request changes to incorrect information.
- Save this card as a reminder to access your K-1 from our website in late February each year.

NOTE: Enbridge Energy Management, LLC shareholders do not receive K-1s and do not require yearly tax forms.

our Lakehead System and into a third-party pipeline at Clearbrook, Minn. The North Dakota System comprises approximately 240 miles of crude oil gathering and a 730-mile transmission pipeline. The Phase VI expansion of the North Dakota System was completed at the end of 2009 and placed into service on Jan. 1, 2010. This expansion—which included upgrades to pumping stations, additional tankage and extensive use of drag reducing agents—increased the North Dakota System's capacity from 110,000 Bpd to 161,000 Bpd.

LOOKING FORWARD

In 2010, we will be proposing increased storage capacity at our Cushing terminal, a critical hub in our infrastructure. We also will be focused on continued expansion of our North Dakota System as producers look to get oil sourced from the Bakken play to Midwestern refining markets. With the 2009 completion of our Southern Access Expansion and with the Alberta Clipper project slated to come online in April 2010, sufficient capacity exists on our mainline system to ensure our ability to deliver secure, reliable North American-sourced crude oil to U.S. and Canadian markets.

LAKEHEAD SYSTEM EXPANSION NEARING COMPLETION

We continued to make great progress in 2009 on our Lakehead System expansion, with critical milestones met and project completion goals on course for 2010 in-service dates.

SOUTHERN ACCESS

We completed Stage 2 of our Southern Access expansion project—a 42-inch diameter pipeline—in 2009. The entire Southern Access Expansion project spans 454 miles from Superior, Wis., to Flanagan, Ill. In 2009, we completed the remaining 133 miles of the project, from Delevan, Wis., to Flanagan, Ill., and placed that line into service on April 1. The entire Southern Access Expansion project has increased capacity on the Lakehead System by 400,000 Bpd and also increased revenues with a related transportation rate surcharge that went into effect when the line was placed into service.

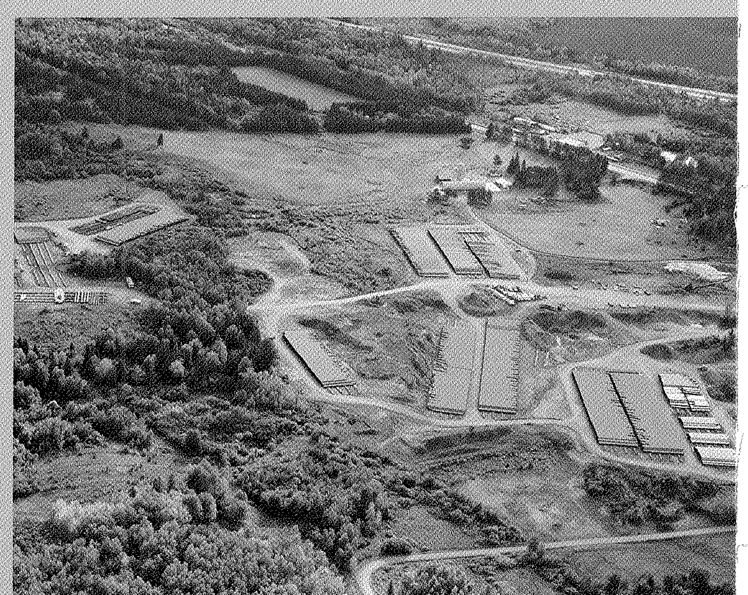
The capacity of Southern Access pipeline can be increased to 1.2 million Bpd through additional pumping stations to accommodate future deliveries via the Alberta Clipper pipeline.

ALBERTA CLIPPER

On August 20, 2009, we received our final permits to allow construction to commence on the United States portion of the Alberta Clipper project. Just as the U.S. portion of the build was beginning, Enbridge Inc. was wrapping up construction on the 670-mile Canadian segment. In total, Alberta Clipper is a 1,000-mile, 36-inch diameter pipeline project, which, when completed, will transport heavy crude oil from Hardisty, Alberta, to Superior. The approximately 330-mile U.S. segment of this new pipeline—from the international border near Neche, N.D., to Superior—costs an estimated $1.3 billion and is being jointly funded by us and our general partner.

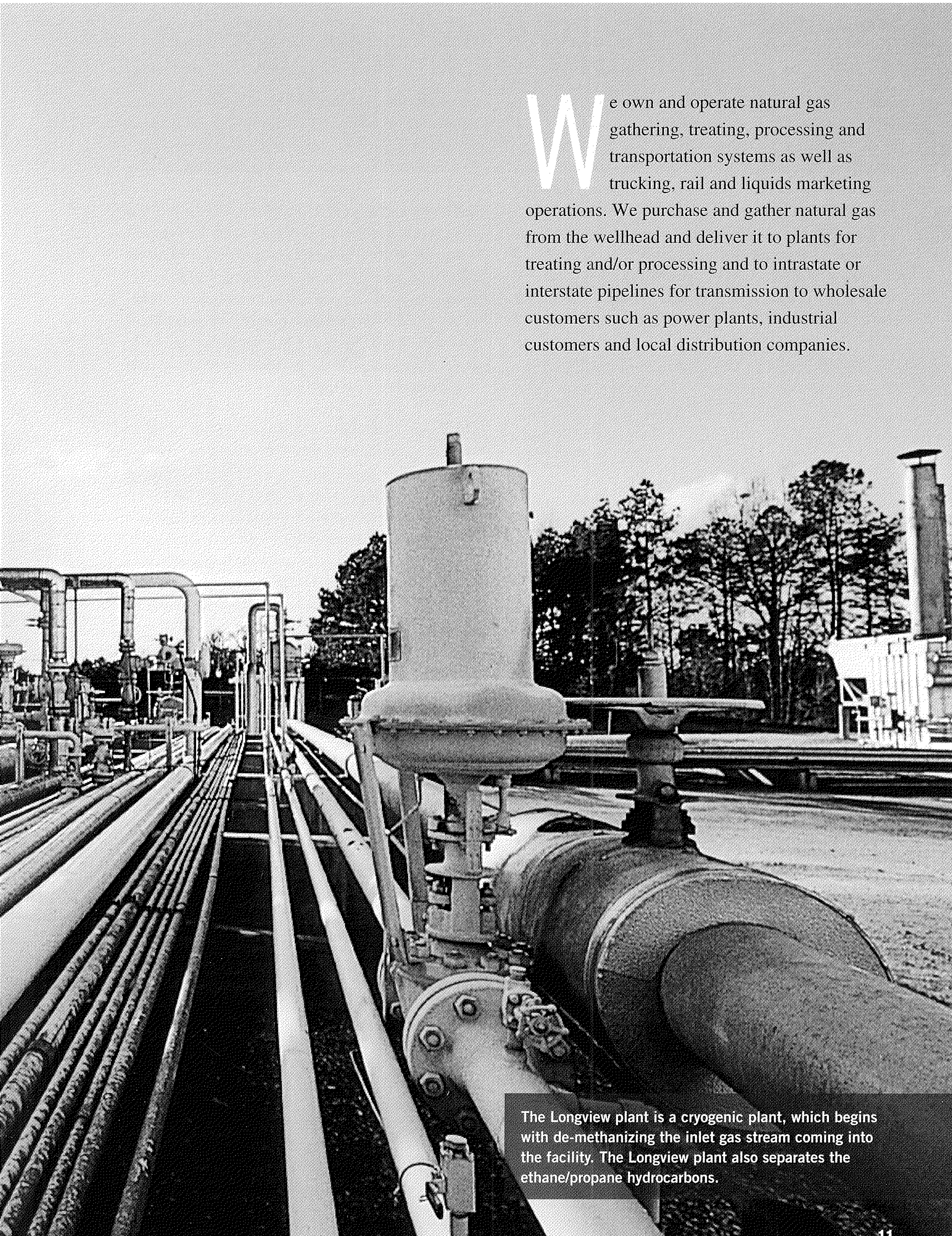
The Alberta Clipper is expected to be placed in service in early April 2010 and will have an initial capacity of 450,000 Bpd, expandable to 800,000 Bpd with additional pumping stations.

Stacks of pipe await being hauled to the Alberta Clipper construction route. This pipeyard, located in Carlton, Minn., holds enough pipe joints to cover more than 60 miles.



NATURAL GAS BUSINESS

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.



The Longview plant is a cryogenic plant, which begins with de-methanizing the inlet gas stream coming into the facility. The Longview plant also separates the ethane/propane hydrocarbons.

Our three major systems – East Texas, Anadarko and North Texas – are located in natural gas production basins that have experienced active drilling production activities during the last several years. The economic crisis combined with more gas supply than expected led to lower prices and lower drilling rates. However, our natural gas assets remain in basins that have the opportunity to grow even in a moderate pricing environment, due to existing shale or tight sands formations where horizontal fractionation technology can be used to improve productivity from the natural gas wells.

MAJOR NATURAL GAS SYSTEM FACTS

East Texas System

Length: 3,400 miles of gathering and transmission pipe

Plants: 9 treating, 7 processing

Anadarko System

Length: 1,800 miles of gathering and transmission pipe

Plants: 6 processing

North Texas System

Length: 4,500 miles of gathering pipe

Plants: 9 processing

We operate approximately 10,000 miles of natural gas gathering and transportation pipelines, nine active natural gas treating plants and 22 active natural gas processing plants with a combined capacity of 2.9 billion cubic feet per day (Bcf/d). Our focus primarily has been on developing and expanding the service capability of our existing pipeline systems. In late 2009, the Partnership sold non-core natural gas pipeline assets and related treating facilities in Louisiana, Alabama, Mississippi and Tennessee, including two FERC-regulated interstate natural gas transmission pipeline systems.

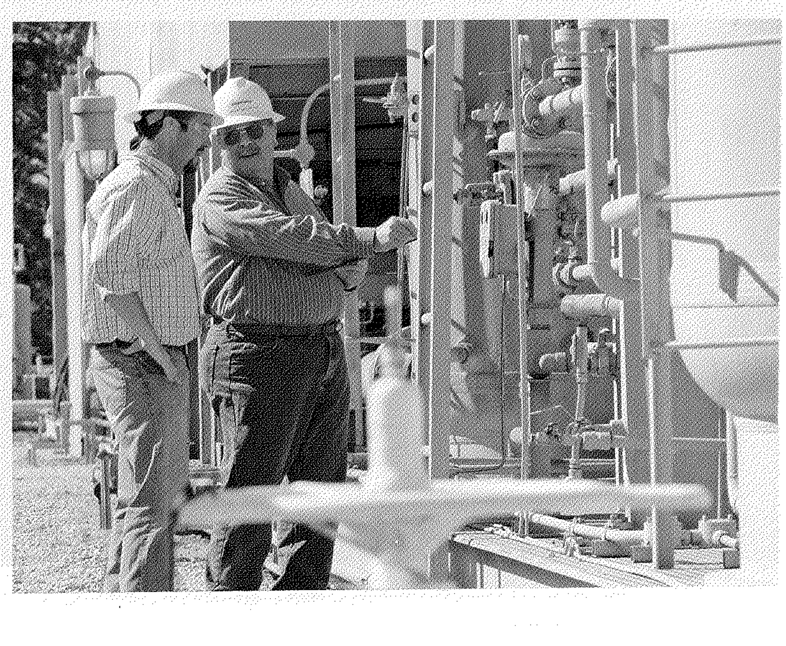
EAST TEXAS SYSTEM

In February 2009, we completed construction on our Orange Texas Compressor Station, the last remaining facility of our $655 million expansion and extension of the East Texas System, referred to as the Clarity project. The Clarity pipeline enables us to provide service to major industrial companies in southeast Texas with interconnects to interstate pipelines, intrastate pipelines and wholesale customers. Clarity is positioned for potential upstream and downstream expansions to meet the growing demand for natural gas transportation capacity.

In the second quarter of 2009, we completed a $60 million expansion project to add compression and approximately 26 miles of 20-inch diameter pipeline within our East Texas System. The completed expansion provides an additional 160 million cubic feet per day (MMcf/d) of capacity for this growing region. We are undertaking $180 million in expansions to provide gathering, treating and transportation services to several producers in counties west and south of Carthage, Texas.

The Bossier trend, located on the western side of our East Texas System within the East Texas Basin, has seen a significant drop in development with production falling from 2,400 MMcf/d in March 2009 to 1,950 MMcf/d in October 2009, partly due to the drop in natural gas prices. However, this decreased drilling activity in the Bossier is expected to be more than offset by the increased activity focused in and around the Haynesville Shale, a formation that runs from western Louisiana and into eastern Texas, and has the potential of being one of the largest natural gas discoveries in the United States. If proven, the discovery could create more drilling activity around our East Texas System, increasing the demand for our services. The potential natural gas production in this region exceeds 1 Bcf/d, primarily from Haynesville wells.

Our East Texas System comprises approximately 3,400 miles of natural gas gathering and transportation pipelines, nine natural gas treating plants and seven natural gas processing plants, including three hydrocarbon dewpoint control facilities, or HCDP plants.



ANADARKO SYSTEM

The Partnership's Anadarko System, located within the Anadarko Basin in the Texas Panhandle and western Oklahoma, has experienced considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler Counties in Texas. Although rig counts were down by 63 percent during the first half of 2009, causing a decline in natural gas production in the region, volume recently has begun to rise slightly. While rig counts in early 2010 were still well below the peak levels of 2008, producers are drilling considerably more horizontal wells in the region and the early results have been promising with high initial production rates. Natural gas in this region has a high content of natural gas liquids (NGLs), which enhances the economics of these wells due to the value of the natural gas liquids.

Our Henderson natural gas processing plant, located in Henderson, Texas, is part of our East Texas System. Both a cryogenic processing plant and a propane refrigeration plant are components of the facility.

Volumes on our Anadarko System are expected to stay level or potentially rise slightly due in part to high prices for NGLs.

The Anadarko System consists of approximately 1,800 miles of natural gas gathering and transportation pipelines in southwestern Oklahoma and the Texas Panhandle and includes six natural gas processing plants.

NORTH TEXAS SYSTEM

A substantial portion of natural gas on our North Texas System is produced in the Barnett Shale area within the Fort Worth Basin Conglomerate, a mature zone that is experiencing slow production decline. In contrast, the Barnett Shale area is one of the most active natural gas plays in North America. We anticipate that throughput on the North Texas System will increase modestly in each of the next several years as a result of continued Barnett Shale development. That is, producers will continue to balance the economics of lower commodity prices with the prolific drilling opportunities of the Barnett Shale. The North Texas System includes approximately 4,500 miles of natural gas gathering pipelines and nine natural gas processing plants.

At the Longview facility, William McBride, plant operator, left, and Pat Moran, plant supervisor, adjust a flow controller on one of the solar turbines.

OTHER NATURAL GAS BUSINESSES

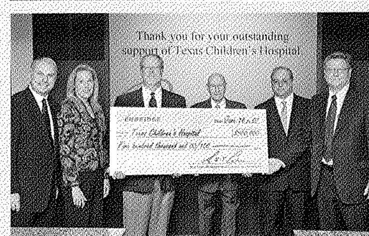
The Partnership's natural gas business also includes trucking, rail and liquids marketing operations through our subsidiary Dufour Petroleum that we use to enhance the value of NGLs produced at our processing plants. Dufour's operations include the transportation of NGLs, crude oil and other products from wellheads and treating, processing and fractionation facilities to wholesale customers, such as distributors, refiners and chemical facilities. Dufour operates a fleet of 210 trucks, 351 trailers and 110 railcars.

The Partnership's natural gas marketing business, Enbridge Marketing, provides natural gas supply, transportation, balancing, storage and sales services to producers and wholesale customers. Our marketing business'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. Due to increased volumes from our gathering assets, our marketing business leases third-party pipeline capacity downstream from our natural gas assets under firm transportation contracts for various lengths and at rates that allow our marketing business to diversify its customer base by expanding its service territory. This transportation capacity also provides assurance that our natural gas will not be shut in, which can result from capacity constraints on downstream pipelines.

GOVERNANCE AND SOCIAL RESPONSIBILITY

At Enbridge Energy Partners, L.P., our commitment to ethical conduct, social responsibility and good governance is core to our way of doing business. To us, good corporate governance means ensuring that a comprehensive system of stewardship and accountability is in place and functioning among the boards of directors, management and employees of our general partner and Enbridge Energy Management, L.L.C. We believe social responsibility means achieving business success in ways that uphold our values and high standard of ethics and demonstrate respect for people and the environment. To that end, we believe that social responsibility and promotion of a sustainable future go hand-in-hand with the strong financial performance our investors expect.

The boards of directors, management team and skilled employees of our general partner and Enridge Energy Management, L.L.C. are the backbone of Enbridge Energy Partners, L.P. The boards, which function independently of management, provide guidance on our long-range strategic planning and approve all significant decisions that affect our direction. The governance provided by the experienced boards and the value of ties with Enbridge on mutually beneficial expansions are strengths that will contribute to future long-term success.



Top: In 2009, we were honored with a Natural Gas STAR for Continuing Excellence from the Environmental Protection Agency, recognizing the Partnership's five-year participation in the voluntary program to reduce methane emissions. Bottom left: We are a proud supporter of Texas Children's Neurological Research Institute, the world's first dedicated pediatric neurological research facility. Bottom right: Enbridge employees across the United States participate in United Way campaigns, including a Day of Caring service project in Houston.

MEMBERS OF THE ENBRIDGE ENERGY COMPANY, INC. (EECI) AND ENBRIDGE ENERGY MANAGEMENT, L.L.C. (EEQ) BOARDS OF DIRECTORS

Martha O. Hesse is chairman of the boards effective May 1, 2007 and is a member of the boards' Audit, Finance and Risk Committees.

Jeffrey A. Connelly was elected a director of EECI and EEQ in January 2003 and serves as the chairman of the boards' Audit, Finance and Risk Committees.

Stephen J.J. Letwin was elected managing director and as a member of the boards of directors of EECI and EEQ in May 2006.

Terrance L. McGill was elected president and a director of EECI and EEQ in May 2006.

George K. Petty was elected a director of EECI in February 2001 and of EEQ in May 2002 and serves on the boards' Audit, Finance and Risk Committees.

Dan Westbrook was elected a director of EECI and EEQ in October 2007 and is a member of the boards' Audit, Finance and Risk Committees.

Stephen J. Wuori was elected a director in January 2008 and is the executive vice president – Liquids Pipelines for EECI and EEQ.

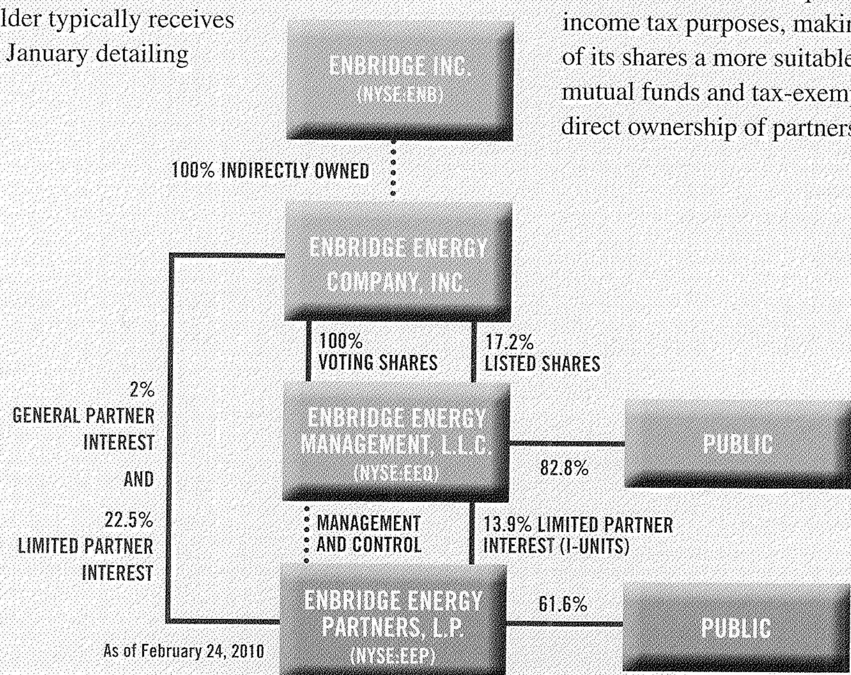
A CHOICE OF INVESTMENTS

Two alternatives are available for equity investors wanting to own an interest in our portfolio of energy transportation assets. The first is via class A common units representing limited partner ownership interests of Enbridge Energy Partners, L.P., which are publicly traded on the New York Stock Exchange (NYSE) under the symbol EEP. These units represent a direct interest in a traditional master limited partnership. An investment in a partnership differs in a number of significant ways from an investment in a corporation.

- A unitholder (partner) in a publicly traded partnership owns units of the partnership rather than shares of stock and receives cash distributions rather than dividends. Cash distributions received generally reduce a partner's tax basis in the partnership. The cash distributions are not taxable as long as the partner's tax basis exceeds zero.
- Typically, a corporation is subject to federal and state income taxes, but a partnership is not. All of the income, gains, losses and deductions of a partnership are passed through to its partners, who are required to show their allocated share of these amounts on their income tax returns. Allocated taxable income increases a partner's tax basis in the partnership.
- In late February, partners are provided a tax package (Schedule K-1) required for preparation of their personal income tax returns. By comparison, a corporate stockholder typically receives a Form 1099 in late January detailing required tax data.

The second choice available to equity investors is shares of Enbridge Energy Management, L.L.C., which is a limited liability company that trades publicly on the NYSE under the symbol EEQ. These shares represent an indirect investment in Enbridge Energy Partners, L.P. since Enbridge Management's only investment is its interest in the Partnership. Further, the performance of Enbridge Management shares is generally expected to track that of the Partnership, since its shares are maintained on a one-for-one basis with a specific class of Enbridge Partners limited partner units. An investment in EEQ shares differs from an investment in EEP partnership units in a number of significant ways.

- Enbridge Management shareholders receive quarterly distributions in the form of additional shares. The distributions are comparable in value to the quarterly cash distributions paid to unitholders of Enbridge Partners.
- Enbridge Management distributions are not taxable when received, and shareholders are not issued either a Schedule K-1 or a 1099 tax form. The sale of Enbridge Management shares is generally subject to capital gains treatment, thus providing a tax-efficient form of investment.
- These investment attributes result in shares of Enbridge Management being attractive to many individual investors. In addition, Enbridge Management is treated as a corporation for federal income tax purposes, making ownership of its shares a more suitable investment for mutual funds and tax-exempt investors than direct ownership of partnership units.



FINANCIAL HIGHLIGHTS

	For the year ended December 31,				
	2009	2008	2007	2006	2005
Financial (dollars in millions)					
Operating revenue	**$ 5,731.8**	$ 9,898.7	$ 7,172.1	$ 6,400.2	$ 6,375.9
Net income	**328.0**	403.2	249.5	284.9	89.2
Adjusted operating income*	**614.0**	532.7	381.2	326.8	239.6
Adjusted net income*	**377.1**	355.3	281.1	228.8	143.7
Per Unit (In dollars)					
Net income	**2.24**	3.64	2.46	3.62	1.06
Adjusted net income*	**2.75**	3.15	2.82	2.84	1.92
Cash distributions	**3.96**	3.88	3.725	3.70	3.70
Operating					
Deliveries Liquids Segment (Bpd in thousands)					
Lakehead System	**1,650**	1,620	1,543	1,517	1,339
North Dakota System	**116**	111	98	92	87
Mid-Continent System	**238**	231	236	244	236
Total	**2,004**	1,962	1,877	1,853	1,662
Deliveries Natural Gas Segment (Btu/d in billions)					
East Texas System	**1,443**	1,479	1,180	1,019	860
Anadarko System	**570**	647	591	582	488
North Texas System	**387**	395	348	294	265
Total	**2,400**	2,521	2,119	1,895	1,613

*Adjusted to eliminate certain noncash items and sale of nonstrategic assets. (See reconciliations to GAAP measure below.)

Non-GAAP Reconciliations: Adjusted income figures are provided to illustrate trends absent certain unusual transactions–such as the occasional sale of nonstrategic assets–and excluding adjustments that affect earnings, but do not impact cash flow, such as derivative fair value losses and gains. These noncash losses and gains result from fair market value adjustments for certain financial derivatives used by the Partnership for hedging purposes that, nevertheless, do not qualify for hedge accounting treatment under the applicable authoritative accounting guidance.

ADJUSTED FINANCIAL HIGHLIGHTS

	For the year ended December 31,				
(Unaudited, in millions except per unit amounts)	**2009**	2008	2007	2006	2005
Operating income	**$ 616.6**	$ 580.6	$ 318.4	$ 382.9	$ 185.1
Noncash derivative fair value losses (gains)	**15.7**	(68.8)	62.8	(64.4)	56.3
Hurricane impact	—	15.1	—	—	—
Expired joint tariff revenues	**(18.3)**	—	—	—	—
Sale of assets					
Gain on sale of assets	—	—	—	—	(18.1)
Settlement of financial instruments	—	—	—	—	16.3
NGL inventory charges	—	—	—	8.3	—
Project write-offs	—	5.8	—	—	—
Adjusted operating income	**614.0**	532.7	381.2	326.8	239.6
Interest expense excluding MTM adjustments	**(230.0)**	(180.6)	(98.4)	(110.5)	(107.7)
Other income	**13.4**	1.9	4.2	8.4	2.4
Income tax expense	**(8.5)**	(7.0)	(5.1)	—	—
Income (loss) from discontinued operations	**(0.4)**	8.3	(0.8)	4.1	9.4
Net income attributable to noncontrolling interest	**(11.4)**	—	—	—	—
Adjusted net income*	**377.1**	355.3	281.1	228.8	143.7
Allocations to General Partner	**(57.0)**	(48.7)	(37.5)	(29.2)	(24.5)
Adjusted net income allocable to limited partners	**$ 320.1**	$ 306.6	$ 243.6	$ 199.6	$ 119.2
Weighted average units	**116.4**	97.1	86.3	70.2	62.1
Adjusted net income per unit	**$ 2.75**	$ 3.15	$ 2.82	$ 2.84	$ 1.92

*Adjusted net income excludes the effect of $64.5 million of losses associated with the disposition of the non-core natural gas assets in 2009 and a gain of $32.6 million in 2007 related to the sale of the Kansas Pipeline System.

COMPANY INFORMATION

2010 DISTRIBUTION DATES

	Q1	Q2	Q3	Q4
Payment Date	**Feb 12**	**May 14**	**Aug 13**	**Nov 12**
Record Date	**Feb 5**	**May 7**	**Aug 5**	**Nov 4**
Ex-Dividend Date	**Feb 3**	**May 5**	**Aug 3**	**Nov 2**
Declaration Date	**Jan 29**	**Apr 28**	**Jul 23**	**Oct 27**

All dates are tentative until approved by the board of Enbridge Energy Management, L.L.C. To be entitled to a declared distribution, investors must have purchased units or shares at least one business day in advance of the ex-dividend date. Commencing on the ex-dividend date, units and shares trade without entitlement to the recently declared distribution.

OWNERSHIP

	As of March 3,		
(In thousands)	**2010**	2009	2008
EEP class A common units	**97,443**	76,089	59,839
EEP class B common units	**3,913**	3,913	3,913
EEP class C units	**—**	20,314	18,415
EEP i-units/EEQ shares	**16,700**	15,248	13,815
Total	**118,056**	115,564	95,982
EEP unitholders (estimate)	**86,000**	87,000	80,000
EEQ shareholders (estimate)	**10,000**	11,000	9,600

TRADING

	For the year ended December 31,		
	2009	2008	2007
EEP class A common units			
High	**$ 54.44**	$ 53.45	$ 61.82
Low	**24.71**	22.33	48.25
Close	**53.69**	25.50	50.54
EEQ shares			
High	**$ 54.32**	$ 53.99	$ 60.16
Low	**23.50**	21.88	47.35
Close	**53.12**	24.45	52.32

ENBRIDGE ENERGY PARTNERS, L.P. (the "Partnership"), headquartered in Houston, is a publicly traded master limited partnership (or MLP) engaged in two main businesses: crude oil and natural gas midstream services. The Partnership's major systems serve premium energy basins in North America, which have strong long-term production profiles.

The Partnership's Class A common units, which trade on the New York Stock Exchange (NYSE) under the symbol EEP, are held by approximately 86,000 investors. An additional 10,000 investors hold an indirect interest in the Partnership through ownership of the shares of Enbridge Energy Management, L.L.C. This limited liability company, which manages the business and affairs of the Partnership, trades on the NYSE under the symbol EEQ.

Enbridge Inc. ("Enbridge"), based in Calgary, Alberta, Canada, holds an approximate 27 percent interest in the Partnership through its U.S. subsidiary, Enbridge Energy Company, Inc. (the general partner of the Partnership). Enbridge shares trade on the NYSE and the Toronto Stock Exchange under the symbol ENB.

STOCK EXCHANGE
The Partnership's class A common units are traded on the NYSE under the symbol EEP. Shares of Enbridge Energy Management, L.L.C. trade on the NYSE under the symbol EEQ.

TRANSFER AGENT AND REGISTRAR
Enbridge Energy Partners, L.P.
and/or Enbridge Energy
Management, L.L.C.
c/o BNY Mellon Shareowner Services
P. O. Box 358015
Pittsburgh, PA 15252-8015
Telephone: (888) 749-9483
TDD: (800) 231-5469
(Hearing Assisted)
www.mellon.com/mis/investors/

EXTERNAL AUDITORS
PricewaterhouseCoopers LLP
1201 Louisiana, Suite 2900
Houston, Texas 77002

INTERNET
enbridgepartners.com
enbridgemanagement.com

TAX WEB
Investor tax information (Schedule K-1) is available on the Partnership's website.

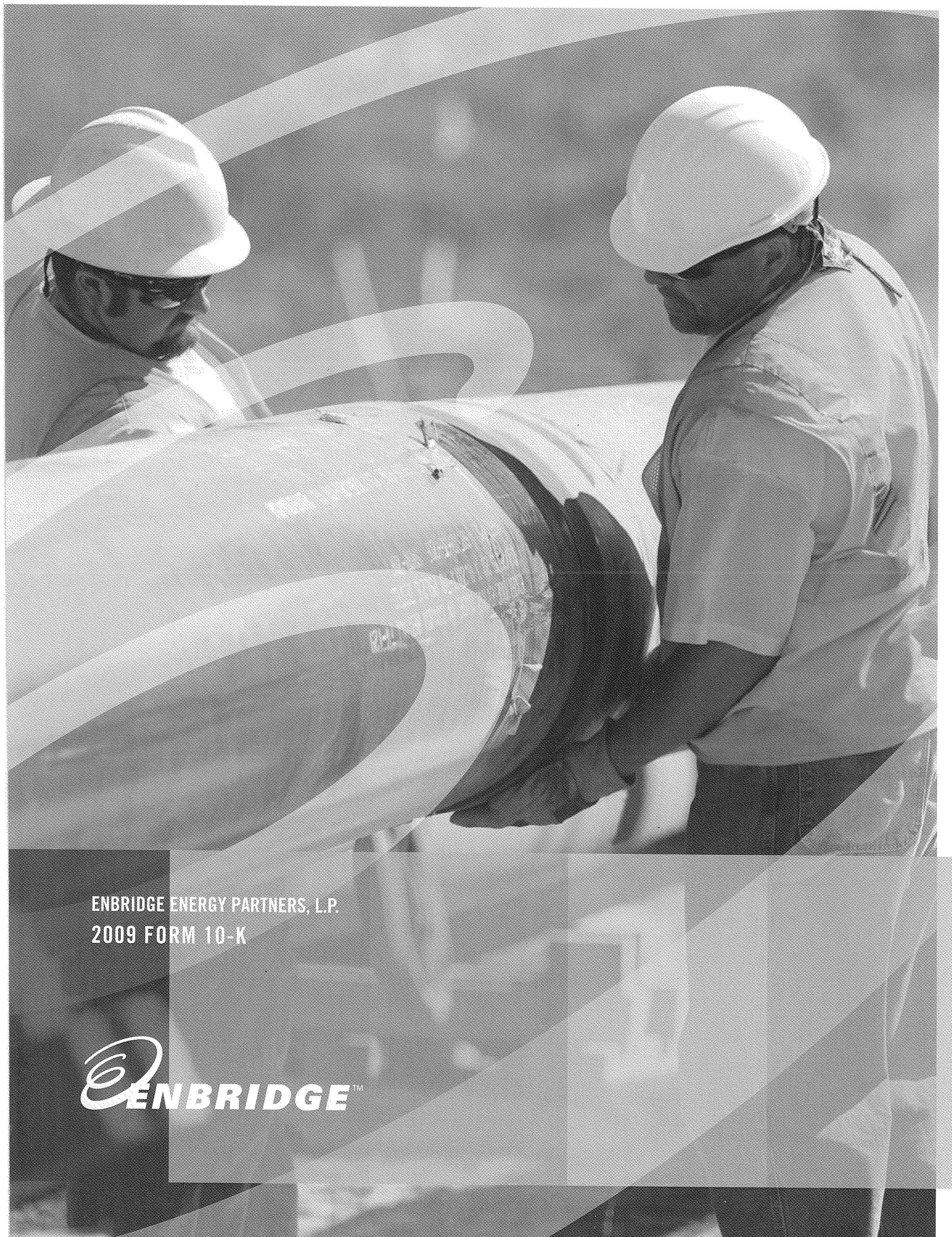
K-1 CALL CENTER
(800) 525-3999
k1@enbridgepartners.com

INVESTOR RELATIONS
(866) 337-4636
(866) EEP-INFO
(866) EEQ-INFO
Fax: (713) 353-5637
eep@enbridge.com
eeq@enbridge.com

MEDIA INQUIRIES
(713) 821-2253
Fax: (713) 821-2230
usmedia@enbridge.com

ENBRIDGE ENERGY PARTNERS, L.P.
ENBRIDGE ENERGY MANAGEMENT, L.L.C.

1100 Louisiana, Suite 3300
Houston, Texas 77002
(888) 650-8900
enbridgepartners.com
enbridgemanagement.com



ENBRIDGE ENERGY PARTNERS, L.P.
2009 FORM 10-K

ENBRIDGE™

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, 2009

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

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**

Securities registered pursuant to Section 12(g) of the Act: NONE

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 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 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 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, 2009, was $2,932,968,652.

As of February 18, 2010 the Registrant has 97,443,352 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

TABLE OF CONTENTS

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements are typically identified by words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "project," "strategy," "target," "could," "should" or "will" and similar words or statements, express or implied, suggesting future outcomes or statements regarding an outlook or the negative of those terms. Although we believe that these forward-looking statements are reasonable based on the information available on the dates these statements are made and processes used to prepare the information, these statements are not guarantees of future performance and readers are cautioned against placing undue reliance on these statements. By their nature, these statements involve a variety of assumptions, unknown risks, uncertainties, and other factors, which may cause actual results, levels of activity and performance to differ materially from those expressed or implied by these statements. Material assumptions may include: the expected supply and demand for crude oil, natural gas and natural gas liquids, or NGLs; prices of crude oil, natural gas and NGLs; inflation rates; interest rates; the availability and price of labor and pipeline construction materials; operational reliability; anticipated in-service dates and weather.

Our forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, interest rates and commodity prices including but not limited to those risks and uncertainties discussed in this Annual Report on Form 10-K and our other reports filed with the Securities and Exchange Commission. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are independent and our future course of action depends on our management's assessment of all information available at the relevant time. Except to the extent required by law, we assume no obligation to publically update or revise any forward-looking statements made herein whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to us or persons actions on our behalf are expressly qualified in their entirety by these cautionary statements. For additional discussion of risks, uncertainties and assumptions, see "Item 1A. Risk Factors" included elsewhere in this Annual Report on Form 10-K.

Glossary

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

AEUB	Alberta Energy and Utilities Board
Anadarko system	Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle which serve the Anadarko Basin.
AOCI	Accumulated other comprehensive income
AOSP	Athabasca Oil Sands Project, located in northern Alberta, Canada
Bbl	Barrel of liquids (approximately 42 U.S. gallons)
Bpd	Barrels per day
CAA	Clean Air Act
CNRL	Canadian Natural Resources Limited, an unrelated energy company
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
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.
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 System
Enbridge Pipelines	Enbridge Pipelines Inc.
EnCana	EnCana Corporation, an unrelated producer of natural gas and crude oil
EP Act	Energy Policy Act of 1992
EPACT	Energy Policy Act of 2005
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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
General Partner	Enbridge Energy Company, Inc., general partner of the Partnership
HCA	High consequence area
ICA	Interstate Commerce Act
KPC	Kansas Pipeline system, sold on November 1, 2007.
Lakehead Partnership	Enbridge Energy, Limited Partnership, a subsidiary of the Partnership
Lakehead system	U.S. portion of the System
LIBOR	London Interbank Offered Rate—British Bankers' Association's average settlement rate for deposits in U.S. dollars.
M^3	Cubic meters of liquid = 6.2898105 Bbl
MLP	Master Limited Partnership
MMBtu/d	Million British Thermal units per day
MMcf/d	Million cubic feet per day
Midcoast system	Natural gas gathering, treating, processing, transmission and marketing assets acquired October 17, 2002.
Mid-Continent system	Crude oil pipelines and storage facilities located in the mid-continent region of the U.S. and including the Cushing tank test 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
NOPR	Notice of Proposed Rulemaking issued by the FERC
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 Burnett shale area.
NYMEX	The New York Mercantile Exchange where natural gas futures, options contracts and other energy futures are traded.
NYSE	New York Stock Exchange
OCSLA	Outer Continental Shelf Lands Act
OSHA	Occupational Safety and Health Administration
OPA	Oil Pollution Act
OPS	Office of Pipeline Safety
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 Idaho, Montana, Wyoming and Colorado
PADD V	Consists of Washington, Oregon, California, Arizona, Alaska, Hawaii and Nevada
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
PHMSA	Pipeline and Hazardous Materials Safety Administration (formerly OPS)
PIPES of 2006	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006
PIPES Act	Pipeline Safety Act Reauthorization of 2006
PPIFG	Producer Price Index for Finished Goods
PSA	Pipeline Safety Act
PSI Act	Pipeline Safety Improvement Act
RCRA	Resource Conservation & Recovery 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
Settlement Agreement	A FERC approved settlement agreement, signed October 1996.
SFPP	Santa Fe Pacific Pipelines, L.P., an unrelated pipeline company
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.

System	The combined liquid petroleum pipeline operations of our Lakehead system and the Enbridge system.
Tariff Agreement	A 1998 offer of settlement filed with the FERC
Terrace	Terrace Expansion Program, an expansion program on our Lakehead system.
TSX	Toronto Stock Exchange
WCSB	Western Canadian Sedimentary Basin

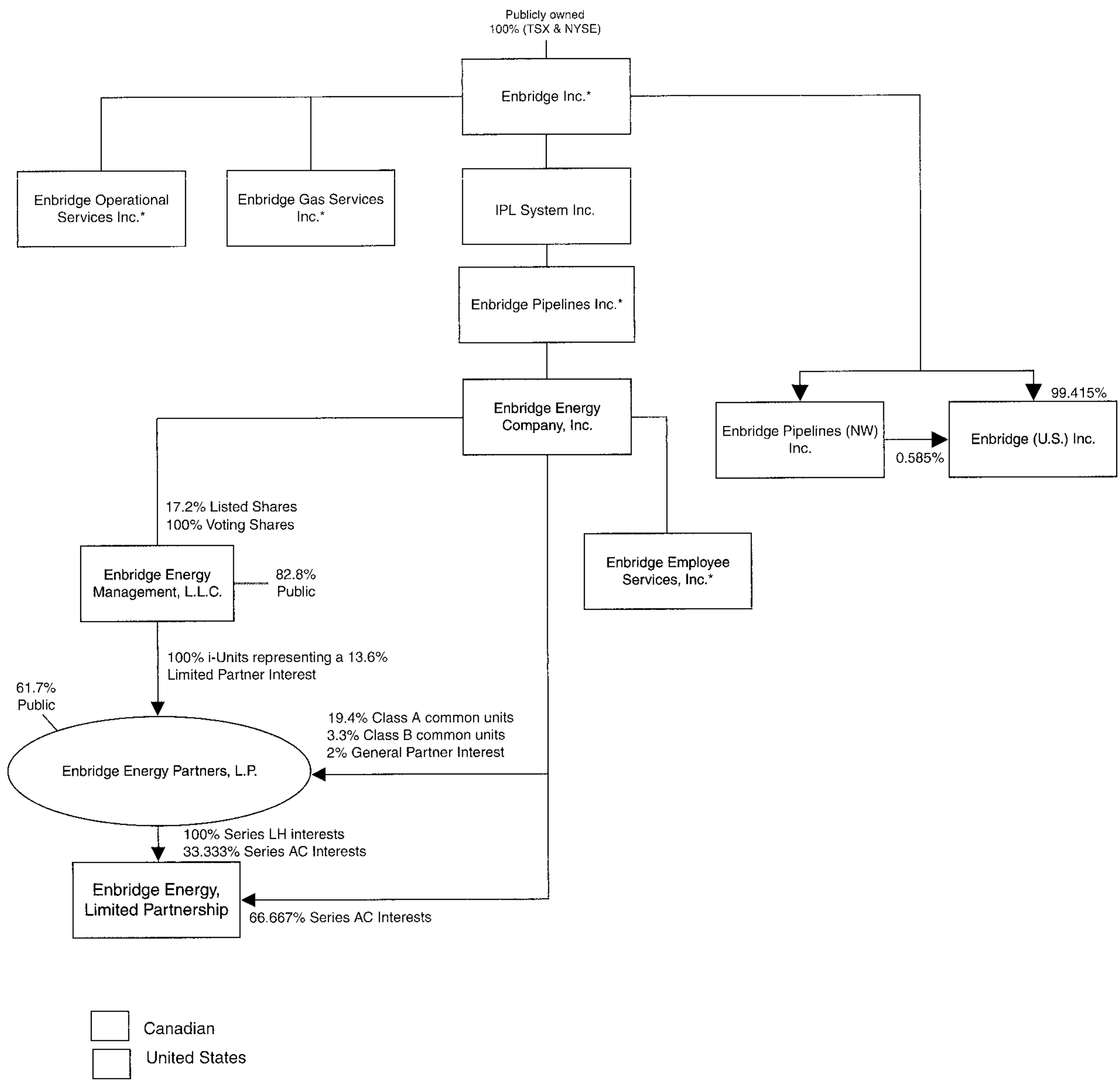
PART I

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 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, 2009. The ownership percentages referred to below illustrate the relationships between us, Enbridge Management, our general partner and Enbridge and its affiliates:



* Denotes Companies that have Employees

Unless otherwise noted, each subsidiary depicted above is 100% owned by its direct parent.

Our ownership at December 31, 2009 and 2008 is comprised of the following:

	2009	2008
Class A common units owned by the public	61.7%	51.2%
Class A common units owned by our General Partner	19.4%	13.9%
Class B common units owned by our General Partner	3.3%	3.4%
Class C units owned by our General Partner[1]	—	5.5%
Class C units owned by institutional investors[1]	—	11.3%
i-units owned by Enbridge Management	13.6%	12.7%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

(1) The Class C units converted to Class A common units in October 2009.

We were formed in 1991 by Enbridge Energy Company, Inc., our general partner, to own and operate the Lakehead system, which is the U.S. 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 (the "System"). A subsidiary of Enbridge Inc., or Enbridge, owns the Canadian portion of the System. Enbridge, which is based in Calgary, Alberta, Canada provides 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, 2009, our portfolio of assets included the following:

- Approximately 5,900 miles of crude oil gathering and transportation lines and 28.9 million barrels, or Bbl, of crude oil storage and terminaling capacity;
- Natural gas gathering and transportation lines totaling approximately 10,000 miles;
- Nine natural gas treating and 22 natural gas processing facilities with an aggregate capacity of approximately 2,900 million cubic feet per day, or MMcf/d. The above amounts include 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 L.L.C., ("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. Focus on operational excellence

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

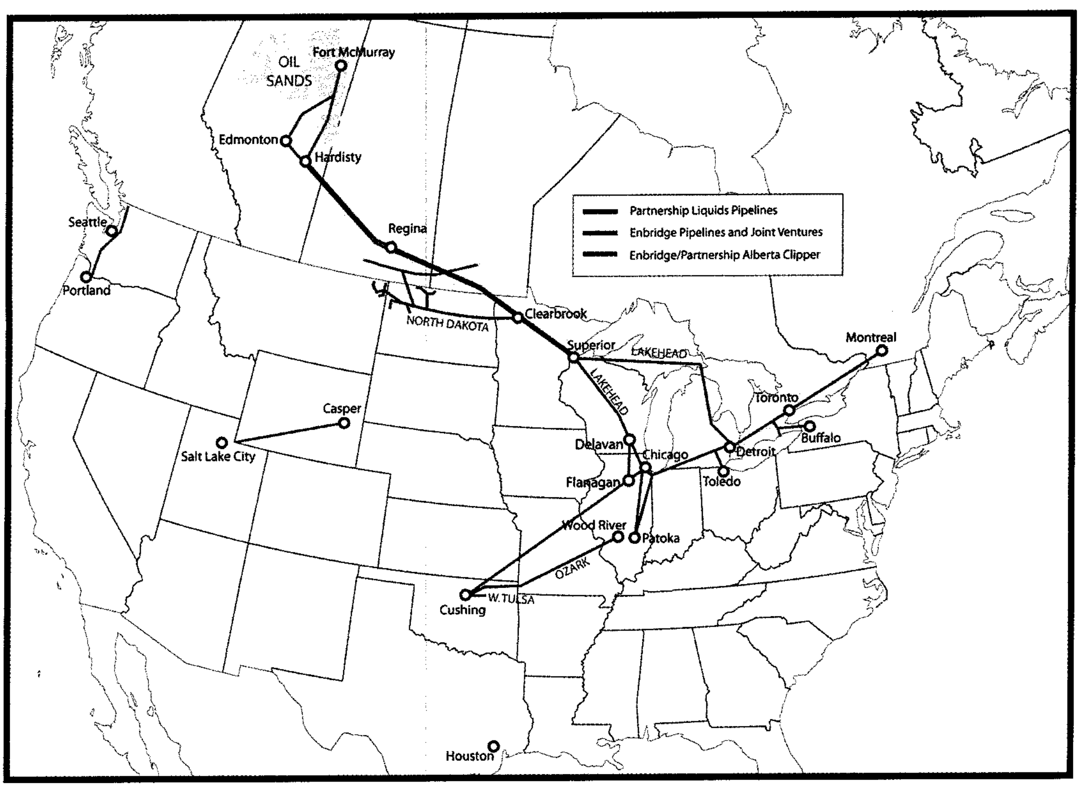
2. Expand existing core asset platforms
   - We intend to develop energy transportation assets and related facilities that are complementary to our existing systems. Our core businesses provide plentiful opportunities to achieve our primary business objectives.
3. Develop new asset platforms
   - We plan to develop and acquire new gathering, processing, transportation and storage 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 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 anticipate initially funding long-term cash requirements for expansion projects and acquisitions first from operating cash flows, second, from borrowings under our Second Amended and Restated Credit Agreement, referred to as the Credit Facility, and from borrowings under our credit agreement with Enbridge (U.S.) Inc., or Enbridge U.S., a wholly-owned subsidiary of Enbridge and from other potential sources of capital.

Enbridge, as the ultimate parent of our general partner, has been and continues to be supportive of our efforts in executing our capital expenditure program as some of these projects are beneficial to our mutual customers and operational asset bases. In addition to Enbridge's recent liquidity support and investment through our general partner, Enbridge has the capacity to provide further support in the form of participation in public and private equity transactions and other forms of investment in our operations.

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.



Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2009 from the U.S. Department of Energy's Energy Information Administration, Canada supplied approximately 1.2 million barrels per day, or Bpd, of crude oil to the U.S., the largest source of U.S. imports. Approximately 68 percent of the Canadian crude oil moving into the U.S. was transported on the System. We have developed and are well positioned to further develop additional infrastructure to deliver growing volumes of crude oil that are expected from the Alberta Oil Sands. Relative to recent years, development of the Alberta Oil Sands has slowed due to changed economic circumstances and volatile commodity prices. The Canadian Association of Petroleum Producers', which we refer to as CAPP, in their June 2009 forecast of future production from the Alberta Oil Sands continued to expect steady growth in supply during the next 10 years albeit at a slower pace than previously forecast, with an additional 1.4 million Bpd of incremental supply available by 2019, based on a subset of currently approved applications and announced expansions.

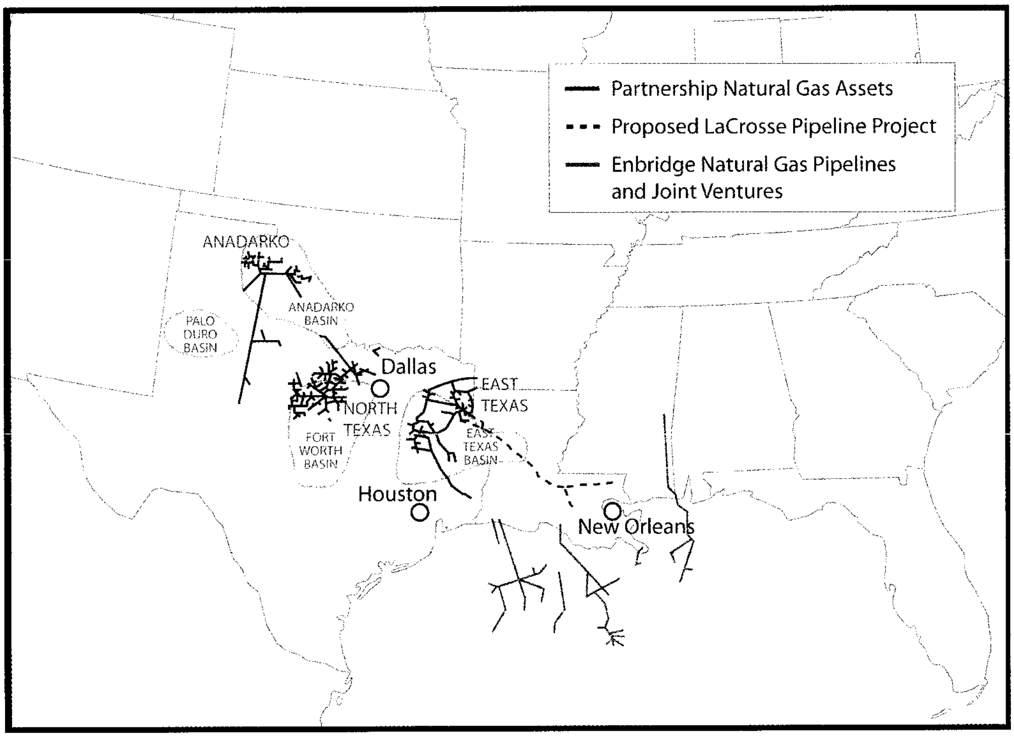
We completed construction on our Southern Access expansion project, which we refer to as the Southern Access Project, in the first quarter of 2009, increasing heavy crude oil capacity of the System into the Chicago, Illinois region by an additional 400,000 Bpd. The Southern Access Project expanded heavy crude oil capacity primarily by the installation of a 42-inch diameter pipeline between Superior, Wisconsin and Chicago. The project was completed as planned and is supported by a system-wide rate surcharge. The design permits an additional 800,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior. The Southern Access Project also involves expansion on the Canadian portion of the system owned by Enbridge.

The Alberta Clipper pipeline expansion project, which we refer to as the Alberta Clipper Project, is under construction and nearing completion. The Alberta Clipper Project involves construction of a new 36-inch diameter pipeline from Hardisty, Alberta to Superior generally within or alongside our existing rights-of-way in the United States and Enbridge's existing rights-of-way in Canada. The Alberta Clipper Project will interconnect with our existing mainline system in Superior where it will provide access to our full range of delivery points and storage options, including Chicago, Toledo, Ohio, Sarnia, Ontario, Patoka, Illinois and Cushing, Oklahoma. The completed pipeline will have an initial capacity of 450,000 Bpd, is expandable to 800,000 Bpd and will form part of the existing Enbridge System in Canada and our Lakehead system in the United States. Construction on the Canadian segment of the Alberta Clipper Project was mechanically completed in December 2009, and remains on schedule to be ready for service on April 1, 2010. As of January 2010, we are approximately 90% complete with construction of the United States segment and it also remains on schedule to be ready for service by April 1, 2010.

Along with Enbridge, we are actively working with our customers to develop options that will allow Canadian crude oil to access new markets in the United States. The market strategy we are undertaking is to provide timely, economical, integrated transportation solutions to connect growing supplies of production from the Alberta Oil Sands to key refinery markets in the United States. The strategy involves further penetration into the Midwest area of the United States, also referred to as PADD II, in addition to expanded and new access to other refining markets in the United States.

Natural Gas

The map below presents the locations of assets for our Natural Gas systems. This map depicts some assets owned or proposed by Enbridge to provide an understanding of how they relate to our Natural Gas systems.



Our natural gas assets are primarily located in Texas, 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 production 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.

One of our key goals is to become the premier midstream energy company in the U.S. Gulf Coast region. To achieve this end, 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, enhance our reputation 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. We have made significant progress on achieving this objective with the construction of our East Texas Expansion project, otherwise known as Clarity, which includes an intrastate pipeline connecting our East Texas system at Bethel, Texas to multiple downstream interconnects and physically connecting a number of our systems. The aim is to be able to move significant quantities of natural gas from our Anadarko, North Texas and East Texas systems to the major market hubs in Texas and Louisiana, which Clarity provides. 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.

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.

The growth prospects in our core areas are primarily the result of historically strong commodity prices, rig utilization rates and improvements in technology to produce natural gas from tight sand and shale formations. As a result, many expansions and extensions have been made on our three main gathering and processing systems in Texas, including well-connects, processing plant re-activations, new plant construction, added compression, new pipelines and treating plant re-activations. However, growth prospects in some of our core areas have been hindered by the current commodity price environment. The volume of gas produced in all three regions has declined as a result of reduced drilling in the area. However, we believe that all three regions continue to have the resource potential to further grow their production volume in the future. The economic return to natural gas producers on horizontal wells in the regions we serve with our pipelines remains attractive when compared to most other gas producing basins. The Haynesville Shale in particular has tremendous potential for growth, and although development of this play first began in Western Louisiana, it is now apparent that the Haynesville Shale extends into several counties in East Texas served by our East Texas system.

We continue to coordinate extensively with our customers to develop and enhance access for Texas natural gas production, to additional markets. One such example is the Clarity project which was successfully completed in late 2008 and had its final compressor station brought on-line in early 2009. The project was designed to be expandable and is positioned for potential upstream and downstream extension.

In addition to the expansions of our transportation capacity to meet the needs of our customers, we have also expanded the processing and treating capacity on our East Texas system to meet the growing demand for these services and to capture the additional revenue these services provide. In the second quarter of 2009, we completed construction on a $60 million expansion project to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. As part of the expansion project, we also increased the capacity of our East Texas system by installing approximately 26 miles of 20-inch pipeline. Additional compression capacity was also added in late 2009.

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 17 of our consolidated financial statements beginning on page F-1 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. Our Lakehead system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. The System, which spans approximately 3,300 miles, has been in operation for 60 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The System serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. We and Enbridge have undertaken the Southern Access Project, Alberta Clipper Project and other expansion projects to increase the capacity of our Lakehead and Enbridge's mainline systems in an effort to capitalize on the expected increases in crude oil supplies from previously announced heavy crude oil and oil sands projects in the Province of Alberta, Canada.

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 4,700 miles of pipe with diameters ranging from 12 inches to 48 inches, 60 pump station locations with a total of approximately 846,450 installed horsepower and 66 crude oil storage tanks with an aggregate capacity of approximately 12.1 million barrels. The System operates in a segregation, or batch mode, allowing the transport of 44 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 2009, approximately 36 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. The 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. Similar to U.S. domestic conventional crude oil production, western Canada's conventional crude oil production is declining. Over the last several years, development of the Alberta Oil Sands has more than offset declining conventional production. The NEB estimated that total production in 2009 from the Western Canadian Sedimentary Basin, or WCSB, averaged approximately 2.5 million Bpd compared with 2.4 million Bpd in 2008. Volumes of WCSB crude oil production are comparable with production volumes from Kuwait and Venezuela, key members of the Organization of Petroleum Exporting Countries, or OPEC.

Remaining established conventional oil reserves in western Canada were estimated to be approximately 3.72 billion barrels at the end of 2007. During 2007, the latest period for which data is available, approximately 97 percent of conventional production was replaced with reserve additions. Remaining established reserves from the Alberta Oil Sands as of the end of 2008 are approximately 170 billion barrels. Canada's combined conventional and oil sands estimated proved reserves of approximately 175 billion barrels compares with Saudi Arabia's estimated proved reserves of approximately 260 billion barrels.

According to CAPP, an estimated $95 billion Canadian Dollars, or CAD, has been spent on oil sands development from 1997 through 2008. Development of the Alberta Oil Sands is expected to moderate due to declining demand and commodity prices, and it is unlikely that all announced and planned oil sands projects will proceed as planned. CAPP's June 2009 Growth Forecast estimates future production from the Alberta Oil Sands is expected to grow steadily during the next 10 years, with an additional 1.4 million Bpd of incremental production available by 2019.

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, facilities. Over the next year, synthetic crude oil production is expected to increase from the ramp up of the joint venture between Opti Canada, Inc. and Nexen, Inc. at their 58,500 Bpd Long Lake upgrader project and Canadian Natural Resources Limited, or CNRL, 114,000 Bpd Horizon upgrader project.

Suncor completed expansion on one of its upgraders in the third quarter of 2008, resulting in total upgrading capacity of approximately 357,000 Bpd. Synthetic production averaged approximately 285,000 Bpd in 2009, which was 59,000 Bpd higher than in 2008. Suncor plans on completing its Firebag Stage 3 expansion as well as Firebag Stage 4 with in-service dates of second quarter 2011 and late 2012, respectively.

Syncrude completed its 100,000 Bpd Stage 3 expansion in 2006, increasing total production capacity to 350,000 Bpd. An extended turnaround in the second quarter of 2009 and operational reliability issues led to average production of 280,000 Bpd, which is 9,000 Bpd lower than 2008. Syncrude's next expansion is the Stage 3 debottleneck to increase their current system synthetic production by approximately 40,000 Bpd, with a projected in-service date that has not been published.

The Athabasca Oil Sands Project, or AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Marathon Oil Corporation (20%), reached full production capacity in 2004. An expansion of the AOSP project moved forward with ERCB's conditional approval of the AOSP Expansion 1 project in 2006. Construction of the AOSP Expansion 1 is in process, and is expected to increase the current production capacity of 158,000 Bpd of synthetic crude oil to 249,000 Bpd by 2010.

Over the next two years, over four individual projects are expected to come on-line that should start or increase the production of unblended bitumen. Notable projects include the expansions at MEG Energy Corp's Christina Lake, StatoilHydro's Kai Kos Dehseh, Suncor's Firebag Stage 3 and Cenovus Energy's Christina Lake. Based on the ERCB forecast, unblended bitumen production is expected to increase by roughly 76,000 Bpd by the end of 2011.

Although the crude oil and liquid petroleum delivered through our Lakehead system originate primarily in oilfields in western Canada, the Lakehead system also receives approximately five percent of its receipts from domestic sources including:

- U.S. production at Clearbrook, Minnesota through a connection with our North Dakota system;
- U.S. production at Lewiston, Michigan; and
- Both U.S. and offshore production in the Chicago area.

Based on forecasted growth in western Canadian crude oil production and completion of upgrader expansions and increased bitumen production, as well as a 435,000 Bpd competitor pipeline coming on-line in 2010, the Lakehead system deliveries are expected to average 1.61 million Bpd in 2010 compared with 1.65 million Bpd in 2009. This decrease is partially due to crude oil volumes needed for line fill for both our Alberta Clipper pipeline as well the competitor's pipeline.

The ability to increase deliveries and to expand the Lakehead system in the future will ultimately depend upon numerous 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, U.S. 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, turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, our Lakehead system.

Although demand for Canadian crude oil in PADD II was fairly consistent with last year, it is expected that demand for WCSB crude oil production will continue to increase. Refinery configurations and crude oil requirements in PADD II continue to be an attractive market for western Canadian supply. According to the U.S. Department of Energy's Energy Information Administration, 2009 demand for crude oil in PADD II was relatively flat when compared to levels in 2008 with an average of 3.13 million Bpd. At the same time, production of crude oil within PADD II increased by 52,000 Bpd to 579,000 Bpd.

The projected growth in western Canadian crude oil production will require construction of new pipelines to ensure expanding oil supplies can be transported to markets in the United States. 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. Periods of low or volatile crude oil pricing in 2009 have caused some oil sands producers to cancel or defer projects that were planned to commence over the next decade. Cancellations and project deferrals of oil sands projects are expected to temper the rate of growth over the next several years relative to prior forecasts. If the rate of crude oil production from the WCSB declines, immediate need for new pipeline infrastructure will likely decline and our Alberta Clipper Project may provide sufficient capacity for the near-term. In the event the rate of crude oil production from the WCSB does indeed decline, we expect expansion activities in and around our Lakehead system to be modest relative to that experienced over the last several years. As a result, further expansion activities in and around our liquids systems will primarily focus on additional storage opportunities in the Cushing region and further development of our North Dakota system. For an overview of our projects refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations by Segment—Liquids—Future Prospects for Liquids."

Competition. The Lakehead system, along with the Enbridge system, is the main crude oil export route from the WCSB. 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 U.S. 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 2009, the latest data available shows that PADD II total demand was 3.13 million Bpd while it produced only 579,000 Bpd and thus imported 2.5 million Bpd. The 2009 data indicate PADD II imported approximately 1.2 million Bpd of crude oil from Canada, a majority of which was transported on the Lakehead system. The remaining barrels were imported from PADDs III and IV as well as from offshore sources through the U.S. Gulf Coast. Lakehead system deliveries of Canadian crude oil to PADD II were 36,000 Bpd higher than delivery volumes for 2008. Total deliveries on our Lakehead system averaged 1.65 million Bpd in 2009, meeting approximately 75 percent of Minnesota refinery capacity; 70 percent of the refinery capacity in the greater Chicago area; and 77 percent of Ontario's refinery demand.

Considering all of the pipeline systems that transport western Canadian crude oil out of Canada, the System transported approximately 68 percent of the total western Canadian crude oil exports in 2009 to the United States. The remaining production was transported by systems serving the British Columbia, PADD II, PADD IV and PADD V markets.

Given the expected increase in crude oil production from the Alberta Oil Sands over the next 10 years, alternative transportation proposals have been presented to crude oil producers. These proposals and projects range from expansions of existing pipelines that currently transport western Canadian crude oil, to new pipelines and extensions of existing pipelines. These proposals and projects are in various stages of development, with some at the concept stage and others that are proceeding with line fill. Some of these proposals will be in direct competition with our Lakehead system.

Enbridge has proposed construction of the Gateway Pipeline with an in-service date in the 2015 to 2016 timeframe, 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.

We and Enbridge believe that the Southern Access Project, Alberta Clipper Project, and other initiatives to provide access to new markets in the Midwest, Mid-Continent 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:

- Construction of a new 435,000 Bpd crude oil pipeline from Hardisty to Wood River, Illinois and Patoka, with capacity subsequently updated to 590,000 Bpd with an expansion to Cushing. The project is expected to receive line fill sometime in 2010.
- Commercial support has been announced to construct a 36-inch crude oil pipeline extension to the pipeline described above that will begin at Hardisty and extend down to Cushing and then to Nederland, Texas. The extension will add an additional 500,000 Bpd of capacity with a targeted in-service date of 2012. The proposed pipeline extension received 380,000 Bpd of shipper support in the third quarter of 2008. An application has been filed with the NEB, and a variety of regulatory approvals will be required in the United States and Canada before the proposed extension can proceed.

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 beyond the Alberta Clipper Project. They could also affect throughput on and utilization of the System. However, together the Lakehead and Enbridge systems offer significant cost savings and flexibility advantages, which are expected to continue to favor the 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.

	Deliveries				
	2009	2008	2007	2006	2005
	(thousands of Bpd)				
United States					
Light crude oil	467	388	346	327	241
Medium and heavy crude oil	834	876	852	872	791
NGL	4	3	4	5	4
Total United States	1,305	1,267	1,202	1,204	1,036
Ontario					
Light crude oil	197	183	184	160	146
Medium and heavy crude oil	73	80	62	63	59
NGL	75	90	95	90	98
Total Ontario	345	353	341	313	303
Total Deliveries	1,650	1,620	1,543	1,517	1,339
Barrel miles (billions per year)	423	432	408	400	338

Mid-Continent system

Our Mid-Continent system, which we have owned since 2004, is located within the PADD II district and is comprised of our Ozark pipeline, our West Tulsa pipeline and storage terminals at Cushing and El Dorado, Kansas. Our Mid-Continent system includes over 480 miles of crude oil pipelines and 15.9 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. Our West Tulsa pipeline moves crude oil from Cushing to Tulsa, Oklahoma where it delivers to Holly Corporation's Tulsa refinery, formally owned by Sinclair Oil Corporation.

The storage terminals consist of 96 individual storage tanks ranging in size from 55,000 to 575,000 barrels. Of the 15.9 million barrels of storage capacity on our Mid-Continent system, the Cushing terminal accounts for 14.8 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 2009, approximately 37 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 system were 238,000 Bpd for 2009 and 231,000 Bpd for 2008.

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 U.S. Gulf Coast, as well as third-party storage demand. In 2009, PADD II imported 2.5 million Bpd from outside of the PADD II region. The 2009 data indicates PADD II imported approximately 1.2 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 supply options available from Canada via our Lakehead system. These same refineries also have access to the U.S. Gulf Coast and foreign crude oil supply through the Capline 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 could face a significant increase in competition when a competitor's new pipeline from Hardisty to Patoka commences operation in 2010. However, when that situation occurs, we will consider potential alternative uses for our Ozark system. In addition, 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.

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

Competition to our West Tulsa pipeline is by way of unrelated parties shipping portions of a local refinery's supply through a pipeline reactivated in mid-2008. This new line was created by modifying existing infrastructure.

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.

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 shale formation. The crude oil gathering pipelines of our North Dakota system collect crude oil from points near producing wells in approximately 22 oil fields 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 161,000 Bpd. We recently completed a 51,000 Bpd increase in capacity resulting from the Phase VI expansion of the system, which we completed in December 2009. This expansion was necessary to meet increased crude oil production from the Montana and North Dakota region. The related tolling surcharge has been adjusted to include costs of this phase of the expansion that became effective January 1, 2010. The commercial structure for this expansion is a cost-of-service based surcharge that was added to the existing transportation rates. Our North Dakota system also has 21 pump stations, one delivery station and 11 storage facilities with an aggregate working storage capacity of approximately 810,000 barrels.

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 largest 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 245,000 Bpd in November 2009. The U.S. portion of the Williston Basin now produces more than 300,000 Bpd.

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.

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 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, 2009, we had nine active treating plants and 22 active processing plants, including three 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 1,200 MMcf/d while the combined capacity of our processing facilities approximates 1,800 MMcf/d, including 550 MMcf/d provided by the HCDP plants.

Our natural gas business consists of the following systems:

- East Texas system: Includes approximately 3,400 miles of natural gas gathering and transportation pipelines, nine natural gas treating plants and seven natural gas processing plants, including three HCDP plants.

- Anadarko system: Consists of approximately 1,800 miles of natural gas gathering and transportation pipelines in southwest Oklahoma and the Texas panhandle and six natural gas processing plants. The Anadarko system also includes the Palo Duro system.

- North Texas system: Includes approximately 4,500 miles of natural gas gathering pipelines and nine natural gas processing plants located in the Fort Worth Basin.

In November 2009, we divested non-core natural gas assets located predominantly outside of Texas, which included over 1,400 miles of pipeline, including interstate and intrastate gas transmission pipelines, and several small gathering and processing assets.

Customers. Customers of our natural gas pipeline systems include both purchasers and producers of natural gas. Purchasers are comprised of marketers, including our Marketing business, and large users of natural gas, such as power plants, industrial facilities and local distribution companies. 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.

Our natural gas pipelines serve customers predominantly in the U.S. Gulf Coast region of the United States. Customers include 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.

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 also depends upon overall economic conditions and the prices of natural gas and NGLs. Due to the current economic conditions and surplus of natural gas, we expect that near-term demand for our services may decrease. Falling drilling rates appear to have stabilized near the end of 2009 and in some regions the number of drilling rigs is rising slightly.

The economic crisis combined with a surplus of natural gas supply expected from the lower 48 states has led to lower prices and lower drilling rates. However, our natural gas assets remain in basins that have the opportunity to grow even in a moderate 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 the driver of growth on our East Texas system for the past several years. Production in the Bossier trend grew from under 390 MMcf/d in 1997 to 2,400 MMcf/d in March of 2009. However, with the drop in natural gas prices, the Bossier trend has seen a significant drop in development with production falling to 1,950 MMcf/d in October 2009, with modest declines experienced in the remainder of the East Texas Basin. This decreased drilling activity in the Bossier trend is expected to be more than offset by the increased activity focused in and around the Haynesville Shale. The Haynesville Shale is a formation that runs from western Louisiana into eastern Texas, and has the potential of being the largest natural gas discovery in the United States. If proven, the discovery could create more drilling activity around our East Texas system increasing the demand for our services. We are undertaking expansions to provide gathering, treating and transportation services to several producers in counties west and south of Carthage.

In a further effort to address the continuing strong growth in natural gas production occurring in east Texas, we successfully completed expansion and extension of our East Texas system, referred to as the Clarity project. The Clarity project included the following portions of expansion which were completed throughout 2008 and 2009:

- Construction of the Orange County compressor station was completed and placed into service in late February 2009;
- The Goodrich compressor station was constructed and placed into service in December 2008;
- A 20-inch segment from Orange County, Texas to a downstream interconnect near Beaumont, Texas, enabling deliveries into the interconnect, was placed into service in December 2008; and
- A 36-inch diameter pipeline segment that extends from Kountze, Texas to Orange County was placed into service in July 2008.

Now that our Clarity project has been completed, we are able to provide service to major industrial companies in southeast Texas with interconnects to interstate pipelines, intrastate pipelines and wholesale customers. The Clarity project was designed to be expandable and is positioned for potential upstream and downstream extensions to meet the growing demand for natural gas transportation capacity.

In the second quarter of 2009, we completed an expansion project to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. As part of the expansion project, we also increased the capacity of our East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. The completed expansion provides an additional 160 MMcf/d of capacity for this growing region.

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 is one of the most 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, technological advances in fracturing the shale formation allows commercial production of these natural gas reserves. Based on the latest information available for 2008, Barnett Shale production has risen from approximately 110 MMcf/d in 1999 to approximately 5,000 MMcf/d by the end of 2008. With substantially reduced drilling in the first half of 2009, production volume was down to 4,750 MMcf/d by October 2009, although the number of drilling rigs began to increase in late 2009. We anticipate that throughput on the North Texas system will increase modestly in each of the next several years as a result of continued Barnett Shale development. The expected increase in throughput is a result of producers balancing the economics of lower commodity prices with the prolific drilling opportunities of the Barnett Shale.

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. However, with rig counts down by 63% during the first half of 2009, production of natural gas in the region fell. Recently volume has begun to rise slightly. While rig counts are still well below the peak levels of 2008, a notable difference is that producers are drilling considerably more horizontal wells in the region, and the early results have been promising with high initial production rates. This development may lead to enhanced recoveries from new and existing wells in this region. An additional factor regarding the development of the wells in this region is the high natural gas liquids content, which enhances the economics of these wells due to the value of the natural gas liquids.

While capital markets have stabilized and our cost of capital approximates pre-financial crisis levels, we will continue to be cautious regarding our capital program. The expansion programs we are undertaking in East Texas to serve the Haynesville Shale developments are being supported by long-term contracts and include demand payments as a significant element of the contractual structure. Other potential expansions may arise as more producers begin actively developing this region and commit for additional capacity. Neither the Anadarko nor the North Texas systems have any major capital programs planned in the near term. However, we will continue to pursue connections for new wells as rig counts increase and will monitor developments closely if volumes appear to rise resulting in the need for added capacity. We will opportunistically evaluate strategic prospects to further expand the service capabilities of our existing system.

Results of our Natural Gas business depend upon the drilling activities of natural gas producers in the areas we serve. We expect that the rate of decline of natural gas production has slowed or halted due to the increase in rig activity. We expect the volumes on our Anadarko system to stay level or possibly rise slightly due to high prices for NGLs and the increased use of horizontal drilling in the Midcontinent region of the United States. Our East Texas and North Texas systems are located in two areas where we believe producers are likely to remain active due to the higher probability of success associated with resource developments in these areas. We believe the higher success rate in these two areas, coupled with the recent natural gas discovery of the Haynesville Shale, should temper the impact of lower natural gas production that generally results from a reduction in drilling activity.

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 our East Texas system, competition is more limited 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, a number of new interstate natural gas pipelines are being constructed in areas currently served by some of our intrastate pipelines. When completed, these new pipelines may compete for customers with our existing pipelines.

Trucking and Liquids Marketing Operations

We also include our trucking and liquids marketing operations in our Natural Gas segment. These operations include the transportation of NGLs, crude oil and other products by 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 liquids 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 half of the volumes transported by our trucking and liquids marketing business and is a major source of its growth in this area.

Our services are provided using trucks, trailers and rail cars, product treating and handling equipment and NGL storage facilities. In 2008, we expanded our fleet by acquiring the assets of a common carrier trucking company to meet the growing supply of NGLs, crude oil and carbon dioxide from our processing facilities, as well as to capitalize on the opportunity to better serve our U.S. Gulf Coast customers. This acquisition increased the size of our truck fleet from 120 to 250 trucks and trailers.

Customers. Most of the customers of our trucking and liquids marketing operations are wholesale customers, such as refineries and propane distributors. Our trucking and liquids 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 U.S. 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 liquids 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 liquids 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 this location.

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

FERC Allowance for Income Taxes in Interstate Common Carrier Pipeline Rates

In December 2005, the FERC released its first case-specific review of the income tax allowance issue reaffirming its income tax allowance policy and directing the pipeline under review to provide certain evidence necessary to determine its income tax allowance. The FERC's *BP West Coast* remand decision and the new tax allowance policy were appealed to the United States Court of Appeals for the District of Columbia Circuit, or the D.C. Circuit Court.

In May 2007, the D.C. Circuit Court upheld the income tax allowance policy adopted by the FERC for master limited partnerships, or MLPs, and other non-taxable entities. On the basis of the Santa Fe Pacific Pipeline, L.P., or SFPP, order, the D.C. Circuit Court concluded that the FERC's new policy statement applied to SFPP and resolved the principal defect of the Lakehead policy, which was the inadequately explained differential treatment of the tax liability of the individual and corporate partners. On that basis, the D.C. Circuit Court affirmed the FERC's tax allowance policy as being reasonable and in accordance with the FERC's statutory discretion. As such, the D.C. Circuit Court affirmed that an allowance should be permitted on all partnership interests, or similar legal interest, if the owner of that interest has an actual or potential income tax liability on the public utility income earned though the interest. We believe that all applicable assets will be entitled to a tax allowance to the extent a pipeline's partners have income tax liability on the income they receive from the pipeline. In August 2007, the D.C. Circuit Court denied a request for rehearing of its May 2007 decision, and the decision is now final and cannot be appealed.

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 Estimated 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 percent 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's Office of Pipeline Safety. 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 F-1 of this annual report on Form 10-K for additional discussion.

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. As common carriers in interstate commerce, these pipelines provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy 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" as well as nondiscriminatory. 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 increased 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 Energy Policy Act of 1992, or 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 should be found to be covered by the grandfathering provisions of 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 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 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 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.

Under Order No. 561, the original inflation index adopted by the FERC was equal to the annual change in the Producer Price Index for Finished Goods, or PPI-FG, minus one percentage point. The index was subject to review every five years. Rates were then subject to an annual adjustment, based upon changes in the PPI-FG minus one percentage point, in order to accurately reflect the actual cost changes experienced by the oil pipeline industry. In December 2000, as part of the FERC's five-year review of the oil-pricing index (July 2001 through June 2006), the FERC concluded that the PPI-FG accurately reflected the actual cost changes experienced by the industry. In February 2003, the FERC issued an Order on Remand, concluding that for the current five-year period, the oil-pricing index should be the PPI-FG. In order to calculate the 2003 ceiling rate levels, oil pipelines were permitted to use the PPI-FG adjustment as though it had been in effect since 2001. As of July 1, 2009, the index was equal to PPI-FG plus 1.3 percentage points, resulting in a positive index adjustment of 7.6025% for the period of July 1, 2009 through June 30, 2010.

In 2010, the FERC is expected to issue a Notice of Inquiry regarding the oil pipeline indexing methodology. The oil pipeline industry, shipper companies and any other interested parties will then have the ability to comment on the existing methodology (PPI-FG plus 1.3%) and provide feedback as to a newly applicable methodology, which is anticipated to go into effect July 1, 2011. The only change expected is an adjustment to the modifier added to or subtracted from the inflation index.

Regulation by the FERC of Intrastate Natural Gas Pipelines

Our Texas 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. Our operations 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.

On December 21, 2007, the FERC issued a notice of proposed rulemaking which proposes to require interstate natural gas pipelines and certain non-interstate natural gas pipelines to post capacity, daily scheduled flow information, and daily actual flow information. On November 20, 2008, the FERC issued Order No. 720, which requires interstate pipelines to post information concerning daily actual flows of no notice service, commencing January 31, 2009. Order No. 720 also requires non-interstate pipelines (i.e., intrastate pipelines) that deliver more than 50 million MMBtu per year to post daily on an Internet website and in FERC-prescribed formats certain information concerning receipt and delivery point capacity and scheduled volumes. The final effective date for required compliance with this FERC order, which is pending until the resolution of requests for rehearing, shall be 150 days following the FERC's issuance of a final order resolving such requests for rehearing. Until the FERC issues such final order, the rules remain subject to change. Adoption of this proposal by the FERC will result in additional administrative costs stemming from the additional record keeping and reporting requirements.

In addition, on November 20, 2008, the FERC issued a notice of inquiry, or NOI, seeking comment on whether it should impose additional reporting requirements on intrastate pipelines providing service under Section 311 of the NGPA, such as several of our East Texas systems. In particular, the FERC seeks comment on whether it should require such pipelines to post the details of their transactions with shippers in a manner more comparable to the requirements applicable to interstate pipelines. FERC has not yet taken any further action on this NOI, and we cannot at this stage predict what, if any, additional reporting requirements may be adopted.

Natural Gas Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own certain natural gas pipelines that we believe meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, as noted in *Intrastate Pipeline Regulation*, above, to the extent our gathering systems buy and sell natural gas, such gatherers, in their capacity as buyers and sellers of natural gas, will be subject to FERC Order 704-A. Additionally, if one of our gathering systems were to fall under the definition of "major non-interstate pipeline," such gatherer would be subject to FERC Order No. 720, as described in *Intrastate Pipeline Regulation* above, subject to a court ruling otherwise. 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 natural gas liquids 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 border crossing points require U.S. government permits that may be terminated or amended at the discretion of the U.S. 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 published tariffs as of December 31, 2009 (including the transportation rate surcharges related to Lakehead system expansions) for transportation on the Lakehead system, the rates for transportation of heavy crude oil from the International Border near Neche, North Dakota, where the Lakehead system enters the United States (unless otherwise stated), to principal delivery points are set forth below:

	Published Transportation Rate Per Barrel
To Clearbrook, Minnesota	$0.3505
To Superior, Wisconsin	0.7356
To Chicago, Illinois area	1.6142
To Marysville, Michigan area	1.9444
To Buffalo, New York area	1.9920
Chicago to the international border near Marysville	0.6593

The transportation rates as of December 31, 2009 for light and medium crude oil and NGLs are lower than the transportation rates 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 indexing methodology and the tariff agreements described below. Upon completion of the Alberta Clipper project, we anticipate filing increased rates for transportation to be effective April 1, 2010.

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 indexing methodology.

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 the SEP II project. 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.

Terrace Surcharge

Under the Tariff Agreement approved by the FERC in 1998, the Lakehead system also implemented a transportation rate surcharge for the Terrace expansion program of approximately $0.013 per barrel for light crude oil from the Canadian border to Chicago. On April 1, 2001, pursuant to an agreement between the

Lakehead system and Enbridge Pipelines Inc., the Lakehead system's share of the surcharge was increased to \$0.026 per barrel. This surcharge was in effect until April 1, 2004, when the Lakehead system's share of the surcharge changed to \$0.007 per barrel. The Lakehead system's share will remain at this level until 2010, at which time the surcharge will return to \$0.013 per barrel through 2013, when the agreement expires. In addition to the Terrace surcharge, included in the tariff agreement is the Terrace Schedule C adjustment. Under the tariff agreement, when Terrace Phase III facilities are in service and annual actual average pumping exiting Clearbrook is less than 225,000 cubic meters, or m^3, per day, an adjustment is made to the Terrace surcharge. In 2009, this adjustment was \$0.03 per barrel, based on annual actual average pumping exiting Clearbrook of 214,100 m^3 per day (1,346,649 Bpd) in 2008.

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 framework to be implemented separately from and incrementally to the then-existing surcharges in its tariff rates ("Facilities Surcharge"). *Enbridge Energy, Limited Partnership*, 107 FERC ¶ 61,336 (2004). The Facilities Surcharge framework 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 Commission approved surcharges already in effect. The Facilities Surcharge Mechanism ("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 Commission permitted the Facilities Surcharge to take effect as of July 1, 2004 and the Facilities Surcharge framework 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 Facilities Surcharge was initially established, four projects were included in the Surcharge: the Superior Manifold Modification Project, the Griffith Hartsdale Transfer Lines Project, the Hartsdale Tanks Project, and the Line 17 (Toledo) Expansion Project.

There were four facilities added to the FSM on February 29, 2008 (Docket No. OR08-10-000): Project 5 (Southern Access Expansion Project); Project 6 (Tank 34 at Superior Terminal and Tank 79 at Griffith Terminal); Project 7 (Clearbrook Manifold); and Project 8 (Tank 35 at Superior Terminal and Tank 80 at Griffith Terminal). These projects were incorporated into the Facilities Surcharge.

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).

On February 27th, 2009, the Lakehead system filed FERC Tariff No. 35 to update the SEP II, Terrace and Facilities surcharges and to reflect the inclusion of three new projects that were supported by CAPP. The three new projects that the Lakehead system sought approval to permit recovery of the costs included: Project 9 (Southern Lights Interim Period Impact); Project 10 (Eastern Access (Trailbreaker) Backstopping Agreement); Project 11 (Line 5 Expansion Backstopping Agreement). On August 28, 2009, FERC accepted the supplement to the Facilities Offer of Settlement (Docket No. OR09-5-000). In 2009, the Facilities Surcharge was \$0.4774 per barrel for light crude movements from the International Border near Neche to Chicago.

Mid-Continent system (Ozark)

Our Mid-Continent 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, West Tulsa, other Mid-Continent system facilities, local area refineries and other interconnected non-affiliated pipelines. Transportation rates for light crude oil from Cushing to principle delivery points are set forth below:

	Published Transportation Rate Per Barrel
To Wood River, Illinois	$ 0.5191
To West Tulsa, Oklahoma	0.2179

The transportation rates as of December 31, 2009, 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. In addition to the routes above, the Mid-Continent system also has a joint tariff with Plains Pipeline, L.P., which allows for transportation from points in Texas and New Mexico to Wood River.

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 Enbridge North Dakota system consists of both gathering and trunkline assets. Effective January 1, 2008, two new surcharges were implemented as a part of the Phase V Expansion program. In August 2006, Enbridge North Dakota submitted the Phase V 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 V 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 are applicable for five years immediately following the in-service date of the Phase V Expansion program, 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. Gathering rates in effect are $0.7186 per barrel. The looping surcharge was modified in 2009 to extend the cost recovery period by an additional four years.

Effective January 1, 2010, we increased the rates for transportation on our North Dakota System to include a new surcharge related to the recent completion of our Phase VI Expansion program, which increased capacity on the line from 110,000 Bpd to 161,000 Bpd. This surcharge is applicable for the seven years immediately following the in-service date of the Phase VI Expansion program. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook and the looping surcharge is applied to all volumes originating at Trenton and Alexander. The rates and surcharges for transportation of light crude oil to principal delivery points via trunklines on our North Dakota System are set forth below:

	Published Rate per Barrel FERC No. 61[1]	Phase VI Surcharge Per Barrel	Published Rate per Barrel FERC No. 64[2]
From Glenburn, Haas, Minot, Newberg, Sherwood, Stanley and Wiley, North Dakota to Clearbrook, Minnesota	$ 1.0495	$ 0.6078	$ 1.6573
From Brush Lake and Dwyer, Montana and Grenora, North Dakota to Clearbrook, Minnesota	1.1763	0.6078	1.7841
From Clear Lake, Dagmar, Flat Lake and Reserve, Montana to to Clearbrook, Minnesota	1.2043	0.6078	1.8121
From Tioga, North Dakota to Clearbrook, Minnesota	1.0774	0.6078	1.6852
From Trenton and Missouri Ridge, North Dakota to Clearbrook, Minnesota	2.0130	0.6078	2.6208
From Alexander, North Dakota to Clearbrook, Minnesota	2.0550	0.6078	2.6628
From Brush Lake, Dagmar and Clear Lake, Montana to Tioga, North Dakota	0.5496	—	0.5496
From Reserve, Montana to Tioga, North Dakota	0.6200	—	0.6200
From Trenton and Missouri Ridge, North Dakota to Tioga, North Dakota	1.2171	—	1.2171
From Alexander, North Dakota to Tioga, North Dakota	1.2589	—	1.2589

(1) Pursuant to FERC Tariff No. 61 as filed with the FERC on May 29, 2009, with an effective date of July 1, 2009.

(2) Pursuant to FERC Tariff No. 64 as filed with the FERC on November 30, 2009, with an effective date of January 1, 2010.

Safety Regulation and Environmental

General

Our transmission and gathering pipelines and storage and processing facilities 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 non-rural gathering pipelines are subject to regulation by the United States Department of Transportation, or DOT, Pipeline and Hazardous Materials Safety Administration, or PHMSA, under Title 49 of the United States Code of Federal Regulations (Pipeline Safety Act, or PSA) relating to the design, installation, testing, construction, operation, replacement and management of transmission and non-rural gathering pipeline facilities. PHMSA is the agency charged with regulating the safe transportation of hazardous materials under all modes of transportation, including 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.

In 1999 PHMSA published a final rule regarding the qualification of pipeline operations personnel. The "Operator Qualification" regulations require pipeline operators to utilize qualified individuals to perform pipeline operations and maintenance activities or tasks. The rule required pipeline operators to have a written plan in place by April 27, 2001 and to complete qualification of personnel by October 28, 2002. We have prepared an Operator Qualification Plan which is in compliance with the final rule. The implementation of this plan does not have a material effect on the operations of our pipelines.

On December 17, 2002, the Pipeline Safety Improvement (PSI) Act of 2002 was enacted reauthorizing and amending the PSA. The most significant amendment required natural gas pipelines to develop integrity management programs and conduct integrity assessment tests at a minimum of seven year intervals. Such tests can include internal inspection, hydrostatic pressure tests or direct assessments on pipelines in certain high consequence areas. PHMSA has since promulgated rules for this and other mandates included in the PSI Act of 2002.

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 Pipeline Safety Act. Many of the provisions were welcome, including strengthening excavation damage prevention and enforcement. The most significant provisions of PIPES of 2006 that will 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.

We have incorporated the new requirements of the 2002 and 2006 PSA amendments into procedures and budgets and, while we expect to incur higher regulatory compliance costs, the increase is not expected to be material.

When hydrocarbons are released into the environment, the PHMSA can impose a return-to-service plan, which can include implementing certain internal inspections, pipeline pressure reductions, and other strategies to verify the integrity of the pipeline in the affected area. We do not anticipate any return-to-service plans that will have a material impact on system throughput or compliance costs; however, we have the potential of incurring expenditures to remediate any condition in the event of a discharge or failure on our systems.

Our trucking and railcar operations are also subject to safety and permitting regulation by the DOT and state agencies with regard to the safe transportation of hazardous and other materials.

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 expenses 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 which 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 leaks or spills of crude oil, liquids or 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 2009, the Environmental Protection Agency, or EPA, published the Greenhouse Gas Recordkeeping and Reporting Rule, which requires applicable facilities to record and report greenhouse gas emissions beginning January 1, 2010. 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.

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 leak. 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.

Employee Health and Safety. The workplaces associated with our operations are subject to the requirements of the federal Occupational Safety and Health Administration, or OSHA, and comparable state statutes that regulate worker health and safety. We have an ongoing safety, procedure and training program for our employees and believe that our operations are in compliance with applicable OSHA requirements, including industry consensus standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

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, 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 insurance coverage for our operations and properties considered to be customary in the industry. The coverage limits and deductible amounts at December 31, 2009 for our insurance policies denominated in CAD and United States dollars ("USD") were as follows:

Insurance Type	Coverage Limits		Deductible Amount	
	CAD	USD[1]	CAD	USD[1]
	(in millions)		(in millions)	
Property and business interruption	Up to $700.0	Up to $668.9	$ 10.0	$ 9.6
General liability	Up to $569.0	Up to $543.7	0.1	0.1
Pollution liability	Up to $569.0	Up to $543.7	5.0	4.8

(1) Based on an exchange rate at December 31, 2009 of $1.0466 CAD to $1 USD when coverage was renewed.

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, 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 file annual, quarterly and other reports, and any amendments to those reports, and information with the Securities and Exchange Commission, or SEC, under the Securities Exchange Act of 1934, as amended, which we refer to as the Exchange Act. You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site at *http://www.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us.

We also 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 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 2009, 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 borrowing capacity under our Credit Facility.

Standard & Poor's ("S&P"), Dominion Bond Rating Service ("DBRS") and Moody's Investors Service ("Moody's") rate our non-credit enhanced, senior unsecured debt at "BBB" with a stable outlook, BBB with a stable outlook and "Baa2" with a stable outlook, respectively. Although we are not aware of any 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 Swap and Derivative 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, 2009, we have provided \$14.9 million in the form of letters of credit as assurances of performance for our then outstanding derivative financial instruments. If our credit ratings had declined to BBB- for S&P or Baa3 for Moody's, at December 31, 2009, we would have been required to provide letters of credit in the aggregate amount of \$39.0 million to satisfy this requirement of our ISDA® agreements. The amount 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 Credit Facility.

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 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 or are unable to raise financing on acceptable terms.

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 or be unable to raise, on terms we find acceptable, any debt or equity financing that may be required for any such acquisition.

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 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 the current and future expansions of our Lakehead system, including the Alberta Clipper and Southern Access projects, 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 already done, if crude oil prices remain 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 executing our construction projects to increase 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, U.S. 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.

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 will face a significant increase in competition when a new pipeline from Hardisty to Patoka is completed in 2010.

We also encounter competition in our natural gas gathering, treating, 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 and/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. We are exposed to fluctuations in commodity prices on 10 to 25 percent of the natural gas, NGLs and condensate we expect to receive in the near term. 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 delay 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 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. 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 U.S. House of Representatives passed a cap and trade bill known as the American Clean Energy and Security Act of 2009, which is now being considered by the U.S. Senate. 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 Clean Air Act. In July 2008, the EPA released an Advanced Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act and other potential methods of regulating greenhouse gases. On April 24, 2009, EPA responded to the Massachusetts, et al. v. EPA decision with a proposed 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, 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. Finally, on September 30, 2009, EPA proposed a rule that would, in general, require facilities that emit more than 25,000 tons per year of greenhouse gas equivalents to obtain permits to demonstrate that best practices and technology are being used to minimize greenhouse gas emissions. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted 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. Canada is one of many foreign nations participating in the Kyoto Protocol, a treaty designed to reduce greenhouse gas emissions. The treaty requires Canada to reduce greenhouse gas emissions to 6% below 1990 levels by 2012. While the United States is not a signatory to the Kyoto Protocol, its Congress has been actively considering legislation to reduce emissions of greenhouse gases, primarily through the development of greenhouse gas cap and trade programs.

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 we may bear a part or all of the cost. 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.

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 incidents;
- Degradation, which result from mixing at the interface 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 facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets, 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 partners 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 will issue additional shares;
- 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 2/3% 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 subsidiary's 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 our holders of common units.

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.

Our most significant operating subsidiary is restricted by its First Mortgage Notes from making distributions to us, other than in additional partnership interests in it, unless (1) the distribution is in cash, (2) the distribution amount does not exceed the current available cash of that subsidiary, (3) a default does not exist under the First Mortgage Notes immediately after giving effect to the distribution and (4) timely notice of the distribution has been given to the holders of the First Mortgage Notes. In addition, we are prohibited from making distributions to our unitholders during (1) the existence of certain defaults under our Credit Facility 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 Facility and our subsidiary's First Mortgage Notes 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 facility or our indentures or our subsidiary's First Mortgage Notes 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 Facility, 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 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 (the "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, 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 U.S. 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 federal income tax, including IRAs and other retirement plans, will be "unrelated business taxable income" and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. 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 federal income tax purposes.

We will be considered to have been terminated for 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 1B. Unresolved Staff Comments

The staff of the SEC reviewed our Annual Report on Form 10-K for the year ended December 31, 2008 and issued a letter dated March 31, 2009 commenting on certain aspects of the executive compensation disclosure. We believe that all matters addressed in that letter and subsequent letters and our responses to these letters have been resolved with the exception of certain disclosures related to performance targets. We expect this comment to be resolved in the near future.

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 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 and used by us under easements 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 and used by us under easements or permits.

Substantially all of our Lakehead system assets are subject to a first mortgage lien collateralizing indebtedness of our Lakehead Partnership.

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.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2009.

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 2009 and 2008 are summarized as follows:

	First	Second	Third	Fourth
2009 Quarters				
High	$33.50	$42.87	$48.20	$54.44
Low	$24.71	$29.72	$36.90	$44.05
Cash distributions paid	$0.990	$0.990	$0.990	$0.990
2008 Quarters				
High	$52.00	$53.45	$50.49	$40.86
Low	$43.52	$48.10	$36.50	$22.33
Cash distributions paid	$0.950	$0.950	$0.990	$0.990

On February 18, 2010 the last reported sales price of our Class A common units on the NYSE was $51.05. At February 12, 2010, there were approximately 86,000 Class A common unitholders, of which there were approximately 1,400 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.

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 F-1. See also "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	For the year ended December 31,				
	2009	2008	2007	2006	2005
	(in millions, except per unit amounts)				
Income Statement Data:(2)(3)(4)(5)(6)					
Operating revenue	$5,731.8	$9,898.7	$7,172.1	$6,400.2	$6,375.9
Operating expenses	5,115.2	9,318.1	6,853.7	6,017.3	6,190.8
Operating income	616.6	580.6	318.4	382.9	185.1
Interest expense	228.6	180.6	99.8	110.5	107.7
Other income	13.4	1.9	4.2	8.4	2.4
Income tax expense	8.5	7.0	5.1	—	—
Noncontrolling interest	11.4	—	—	—	—
Income from continuing operations attributable to general and limited partnership interests	$ 381.5	$ 394.9	$ 217.7	$ 280.8	79.8
Income from continuing operations per limited partner unit (basic and diluted)(1)	$ 2.78	$ 3.55	$ 2.10	$ 3.56	$ 0.91
Cash distributions paid per limited partner unit	$ 3.960	$ 3.880	$ 3.725	$ 3.700	$ 3.700
Financial Position Data (at year end):(2)(3)(4)(5)(6)					
Property, plant and equipment, net	$7,716.7	$6,722.9	$5,554.9	$3,824.9	$3,080.0
Total assets	8,988.3	8,300.9	6,891.6	5,223.8	4,428.4
Long-term debt, excluding current maturities	3,791.2	3,223.4	2,862.9	2,066.1	1,682.9
Loans from General Partner and affiliates	269.7	130.0	130.0	136.2	151.8
Partners' capital:					
Class A common units	2,884.9	2,104.0	1,340.7	1,141.7	1,142.4
Class B common units	78.6	85.0	72.9	67.6	67.2
Class C units(7)	—	886.5	874.1	509.8	—
i-units	588.8	553.8	515.3	466.3	421.7
General Partner	251.1	84.7	62.9	47.6	34.6
Accumulated other comprehensive income (loss)	(74.6)	12.9	(294.4)	(189.6)	(302.1)
Noncontrolling interest	341.1	—	—	—	—
Partners' capital	$4,069.9	$3,726.9	$2,571.5	$2,043.4	$1,363.8
Cash Flow Data:(2)(3)(4)(5)(6)					
Cash flows provided by operating activities	$ 728.4	$ 543.3	$ 463.4	$ 321.6	$ 267.1
Cash flows used in investing activities	1,173.6	1,428.3	1,765.0	867.0	437.1
Cash flows provided by financing activities	248.9	1,174.4	1,167.5	640.2	181.5
Additions to property, plant and equipment and acquisitions included in investing activities, net of cash acquired	1,292.1	1,387.1	1,980.2	897.7	531.2

Notes to Selected Financial Data:

(1) The allocation of net income to the General Partner in the following amounts has been deducted before calculating income from continuing operations per limited partner unit: 2009, $57.1 million; 2008, $49.5 million; 2007, $36.2 million; 2006, $30.2 million; and 2005, $23.2 million.

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

Date of Acquisition / Disposition	Acquisition / Disposition Description
November 2009	Disposition of natural gas pipeline assets and related facilities located predominantly outside of Texas.
May 2009	Acquisition of a portion of a crude oil pipeline system running from Flanagan, Illinois to Griffith, Indiana.
November 2007	Disposition of Kansas Pipeline System
April 2006	Acquisition of a natural gas pipeline in east Texas.
December 2005	Disposition of assets on the East Texas and South Texas systems.
January 2005	Acquisition of the natural gas gathering and processing asset in north Texas.

(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
December 2008	9.875% Senior Notes	$500.0
April 2008	6.500% Senior Notes	400.0
April 2008	7.500% Senior Notes	400.0
December 2007	Affiliate Note Payable	130.0
September 2007	Junior Subordinated Notes	400.0
August 2007	Zero coupon notes	200.0
December 2006	5.875% Senior Notes	300.0

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

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

Date of Unit Issuance	Class of Limited Partnership Interest	Number of Units Issued	Net Proceeds Including General Partner Contribution
October 2009	Class A	21,245	$ 1.0
December 2008	Class A	16,250,000	509.8
March 2008	Class A	4,600,000	221.8
May 2007	Class A	5,300,000	308.0
April 2007	Class C	5,930,792	320.8
August 2006	Class C	10,869,565	510.2
December 2005	Class A	136,200	6.2
November 2005	Class A	3,000,000	134.9
February 2005	Class A	2,506,500	127.5

(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 unit Holders	Retained from General Partner	Distribution of Cash
2009	$61.1	$60.3	$2.4	$395.0
2008	54.2	72.2	2.6	286.7
2007	48.4	59.1	2.3	245.4
2006	44.6	10.1	1.0	227.4
2005	41.5	—	0.8	210.6

- The quarterly in-kind distributions of 1.6 million, 1.2 million, 0.9 million, 1.0 million, and 0.8 million i-units during 2009, 2008, 2007, 2006, and 2005, respectively, in lieu of cash distributions; and
- The quarterly in-kind distributions of 1.6 million, 1.6 million, 1.1 million and 0.2 million Class C units during 2009, 2008, 2007 and 2006, respectively, in lieu of cash distributions.

(6) In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Project, with several of our affiliates and affiliates of Enbridge. In exchange for a 66.67 percent ownership interest in the Alberta Clipper project, Enbridge, through our general partner, is funding 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 percent ownership of the Alberta Clipper project, we are funding approximately one-third of the debt financing and required equity of the project, for which we will be entitled to approximately one-third of the project's earnings and cash flows. As a result of this joint funding arrangement, 66.67 percent of earnings associated with the Alberta Clipper project 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 Project when the project received its Presidential Border Crossing Permit from the U.S. Department of State. In conjunction with our application of the provisions of regulatory accounting, we recorded an allowance for equity during construction, referred to as AEDC, of $12.6 million, for the year ended December 31, 2009. We also recorded an allowance for interest during construction, or AIDC, that was $4.5 million for the year ended December 31, 2009. These amounts together represent the $17.1 million in earnings of the Alberta Clipper project for the year ended December 31, 2009, of which we have allocated $11.4 million to noncontrolling interest representing our general partner's 66.67 percent ownership interest in the project.

(7) 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 on page F-1 of this Annual Report on Form 10-K.

IMPACT OF CURRENT ECONOMIC CONDITIONS

The challenging economic conditions we faced at the beginning of 2009 appear to be improving at the outset of 2010. As a result of the decisive steps we took in 2009, we began 2010 with stable investment grade credit ratings combined with adequate capital and liquidity to complete our commercially supported internal growth projects and maintain the current distribution rate to our unitholders. In addition, we are well positioned to pursue opportunities for accretive acquisitions in or near the areas in which we have a competitive advantage.

Throughout the year we took strategic steps to enhance our liquidity position and stabilize our credit ratings. We limited our capital expenditure activities to those projects strategic to us. We enhanced our liquidity and credit ratings by entering into a joint funding arrangement for the United States portion of the Alberta Clipper Project with our general partner and other affiliates of ours and Enbridge. Following our announcement of the Alberta Clipper joint funding arrangement, the major credit ratings agencies removed the negative outlooks on our long-term debt ratings. Finally, in November 2009, in an effort to further satisfy our financing needs, we sold non-core natural gas pipeline assets located predominantly outside of Texas for $150.8 million as we discuss in more detail below in Results of Operations, *Natural Gas—Other Matters*.

The steps we have taken are intended to provide sufficient liquidity to fund our remaining growth programs and sustain the present distribution rate to our unitholders, while preserving our credit rating. Although global economic conditions continue to slowly improve, we will maintain our focus on improving unitholder value through our commercially supported internal growth projects, while continually seeking opportunities to enhance the operational efficiency of our existing systems.

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, 2009, 2008 and 2007. We have removed from "Income from continuing operations," for each period, the amounts comprising the operating results of non-core natural gas pipeline assets that we sold in November 2009 and 2007, which amounts are presented in "Income (loss) from discontinued operations."

	For the year ended December 31,		
	2009	2008	2007
	(in millions)		
Operating Income			
Liquids	$ 462.0	$ 342.2	$ 207.1
Natural Gas	117.8	237.8	89.8
Marketing	42.0	7.7	25.0
Corporate, operating and administrative	(5.2)	(7.1)	(3.5)
Total Operating Income	616.6	580.6	318.4
Interest expense	228.6	180.6	99.8
Other income	13.4	1.9	4.2
Income tax expense	8.5	7.0	5.1
Income from continuing operations	392.9	394.9	217.7
Income (loss) from discontinued operations	(64.9)	8.3	31.8
Net income	328.0	403.2	249.5
Less: Net income attributable to noncontrolling interest	11.4	—	—
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 316.6	$ 403.2	$ 249.5

Contractual arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be significant as evidenced by the volatility of commodity prices during 2008. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in natural gas, NGL and crude oil 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. These systems generate revenues primarily from charging shippers a rate per barrel to gather, transport and store crude oil and liquid petroleum.

Operating income from our Liquids segment increased $119.8 million to $462.0 million for the year ended December 31, 2009 from the $342.2 million contributed for the year ended December 31, 2008. The increase in operating income of our Liquids segment is primarily due to the following:

- Transportation rate increases that went into effect in January, April and July 2009, which include increases in our tolls associated with the annual index rate ceiling adjustments, additional facilities added and a true-up of prior year transportation rate surcharges;
- Completion and start-up of the second stage of our Southern Access Project, and the Phase V expansion of our North Dakota system;

- Higher delivered volumes on our Lakehead system associated with the ongoing development of the oil sands located in Alberta referred to as the Alberta Oil Sands;
- Additional revenue we recognized in 2009 resulting from our joint tolling arrangement with Mustang Pipe Line, LLC, or Mustang;
- Revenue recognized in 2009 resulting from our application of regulatory accounting related to our Southern Access Project and Alberta Clipper Project; and
- Additional spot storage fee revenue generated by our Mid-Continent storage terminal system.

The above increases to operating income were partially offset by:

- Lower average crude oil prices associated with the allowance oil we receive; and
- Increased operating costs and depreciation associated with the additional assets we have placed into service.

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/or sales of natural gas and NGLs.

In November 2009, we sold non-core natural gas pipeline assets located predominantly outside of Texas for cash totaling approximately $150.8 million, excluding any subsequent settlement for working capital as provided in the sale agreement. We have presented in "Income from discontinued operations" the income and loss we derived from these assets for the years ended December 31, 2009, 2008 and 2007. We also recorded net impairment charges of $64.5 million in the year ended December 31, 2009 related to the disposition of these natural gas assets.

The following factors affected the operating income of our Natural Gas business for the year ended December 31, 2009 compared to the same period of 2008:

- Unrealized, non-cash, mark-to-market net losses of $36.4 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance in 2009 compared with $85.0 million of net gains we experienced in the same period of 2008;
- A decrease of approximately $9.2 million in losses associated with the revaluation of our in-kind natural gas imbalances and inventories due to less volatile commodities prices in 2009 as compared with the same period in 2008;
- Decline in transportation volumes associated with lower natural gas production in the areas we serve;
- Improved system gain/loss experience resulting from the processes and quality improvements implemented;
- Hurricanes did not disrupt our operations in 2009 as they did in 2008; and
- Cost reduction measures we instituted in 2009 to address rising operating and administrative costs, partially offset by increased depreciation associated with our completed expansion projects.

Marketing

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

The operating results of our Marketing segment for the year ended December 31, 2009 compared to the same period of 2008 were affected by the following:

- A reduction in operating revenues and additional margin from the sale of natural gas to our customers as a result of narrowing natural gas transportation differentials between market centers and reduced market volatility; and
- Unrealized, non-cash, mark-to-market net gains of $20.7 million in 2009 compared to $16.2 million of losses generated in the same period of 2008 associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance.

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 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. For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, which are recorded as an element of "Cost of natural gas" or "Interest expense" in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ (0.7)	$ (0.1)	$ —
Non-qualified hedges	(35.7)	85.1	(59.0)
Marketing			
Non-qualified hedges	20.7	(16.2)	(3.8)
Commodity derivative fair value gains (losses)	(15.7)	68.8	(62.8)
Corporate			
Non-qualified interest rate hedges	0.5	—	(1.4)
Derivative fair value gains (losses)	$ (15.2)	$ 68.8	$ (64.2)

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:

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Operating Results			
Operating revenues	$ 971.8	$ 773.1	$ 548.1
Operating and administrative	248.4	189.4	156.1
Power	128.1	140.7	117.0
Depreciation and amortization	133.3	100.8	67.9
Operating expenses	509.8	430.9	341.0
Operating Income	$ 462.0	$ 342.2	$ 207.1
Operating Statistics			
Lakehead system:			
United States[(1)]	1,305	1,267	1,202
Province of Ontario[(1)]	345	353	341
Total Lakehead system deliveries[(1)]	1,650	1,620	1,543
Barrel miles (billions)	423	432	408
Average haul (miles)	702	729	725
Mid-Continent system deliveries[(1)]	238	231	236
North Dakota system:			
Trunkline	110	105	91
Gathering	6	6	7
Total North Dakota system deliveries[(1)]	116	111	98
Total Liquids Segment Delivery Volumes[(1)]	2,004	1,962	1,877

(1) Average barrels per day in thousands.

Year ended December 31, 2009 compared with year ended December 31, 2008

Our Liquids segment accounted for $462.0 million of operating income for the year ended December 31, 2009, representing an increase of $119.8 million over the same period in 2008. The favorable results are primarily attributable to transportation rate increases that went into effect during 2009, partially offset by higher operating and administrative costs, and depreciation.

Operating revenue for the year ended December 31, 2009 increased by $198.7 million to $971.8 million from $773.1 million for the same period in 2008. The increase in operating revenue is due to the following:

- Increased average rates for transportation on all of our major systems as construction projects were completed as noted below;
- Additional revenue we recognized in 2009 resulting from our joint tolling arrangement with Mustang;
- Higher delivered volumes on our Lakehead system;

- Additional storage fee revenue generated by our Mid-Continent storage terminal system; and
- Revenue recognized in 2009 resulting from our application of the provisions of regulatory accounting.

These increases in operating revenue were partially offset by lower average crude oil prices associated with the allowance oil we receive in connection with our transportation services.

The increases in average transportation rates on all three Liquids systems contributed approximately $166.2 million of additional operating revenue. The rate increases included the following:

- Effective January 1, 2009, we increased the rates for transportation on our North Dakota system to include an updated calculation of the two surcharges related to the Phase V Expansion program;
- Effective April 1, 2009, we increased the rates for transportation on our Lakehead system in connection with the completion of Stage 2 of our Southern Access Project. We also increased the transportation rates on our Lakehead system for additional facilities we added for which we receive a cost-of-service return and a true-up for costs associated with our Southern Access Stage 1 project; and
- Effective July 1, 2009, we increased the average transportation rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment.

During the year ended December 31, 2009, we recognized an aggregate of approximately $22.5 million of operating revenues associated with our Lakehead system related to prior periods. We recognized $13.5 million of revenue after determining that we had incorrectly invoiced three shippers for transportation services provided from October 2005 through December 2008 in connection with a joint tariff arrangement between Enbridge Energy, Limited Partnership, or the OLP, and Mustang Pipe Line, LLC, or Mustang. We also recognized $9.0 million of revenue during the year ended December 31, 2009 for volumetric differences associated with the transportation of crude oil primarily during the years ended December 31, 2008 and 2007. The volumetric differences resulted from discrepancies between the volumes we measured as delivered to the Mustang pipeline system at Lockport, Illinois and the volumes that Mustang reported as delivered at Patoka.

Average delivery volumes on our Lakehead system increased approximately 1.9 percent, to 1.650 million Bpd for the year ended December 31, 2009 from 1.620 million Bpd during the same period in 2008. This increase contributed an additional $9.5 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily derived from increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands. The increases in crude oil supplies from the Alberta Oil Sands are a result of: two new upgraders that began operations in Northern Alberta during 2009; the ramp-up of expanding bitumen projects; and increased production out of the Bakken formation located in the Williston Basin that covers parts of North Dakota, Montana, and Saskatchewan.

Also contributing to the increase in revenues for the year ended December 31, 2009, was an approximately $11.1 million increase in contract storage and spot storage fees generated by our Mid-Continent storage terminal system. Our Mid-Continent system includes approximately 96 storage tanks we own with a total storage capacity of 15.9 million barrels.

During 2009, we recognized $7.5 million of revenue and a corresponding regulatory receivable for amounts we will recover in future periods under the terms of the transportation agreements established for our Southern Access project. The revenue we recognized is due to fewer volumes being transported on our system than anticipated when our current rates were established under the cost-of-service recovery model. These revenues were earned during 2009, but will not be realized as cash until 2010 when we update our transportation rates to account for the lower actual delivered volume than estimated. In April 2009, we applied the provisions of regulatory accounting to the operations of our Southern Access Project when the facilities rate surcharge associated with the project was approved by the FERC. The rates for the Southern Access Project 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. The rates we are allowed to charge shippers associated with our Southern Access Project include an allowance that provides a rate of return to our partners.

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, 2009 were substantially lower than the average prices for the same period of 2008. For example, the average price of West Texas Intermediate crude oil has decreased approximately 38 percent for the year ended December 31, 2009, as compared with the same period in 2008. As a result of the decrease in crude oil prices, we have experienced an approximate $20.0 million decrease in allowance oil revenues.

Operating and administrative expenses for the Liquids segment increased $59.0 million for the year ended December 31, 2009, compared with the same period in 2008. The increase in these costs is primarily attributable to the following:

- Increased workforce related costs associated with the operational, administrative, regulatory, and compliance support necessary for our systems resulting from the recently completed expansions;
- Higher operating costs associated with our lease of Line 13 from an affiliate of our general partner which contributed $19.3 million to our costs, which we are recovering through a tolling surcharge on our Lakehead system with the net effect on our cash flow and operating income expected to approximate zero over the life of the lease;
- Increased costs for repair and maintenance activities and our pipeline integrity program;
- Property tax increases associated with assets we have constructed and placed in service coupled with modest increases on existing assets. Additionally, no favorable property tax settlements were realized in 2009; and
- Increases in other variable costs incurred in relation to our expanded pipeline systems.

Our general partner charges us the costs associated with employees and related benefits for personnel who are assigned to us or otherwise provide us with managerial and administrative services. We have experienced an increase in workforce related costs as a result of the growth and expansion of our Liquids system operations.

Power costs decreased $12.6 million in the year ended December 31, 2009, compared with the same period in 2008. The decline in power costs is primarily associated with the additional capacity provided by our Southern Access Project that has enabled us to more efficiently utilize our pipelines to transport crude oil.

The increase in depreciation expense of $32.5 million is attributable to the additional assets we have placed in service during 2008 and 2009, the most significant of which are the Southern Access Project stage one and two assets that we placed in service during the second quarter of 2008 and the second quarter of 2009, respectively.

Year ended December 31, 2008 compared with year ended December 31, 2007

Our Liquids segment accounted for $342.2 million of operating income for the year ended December 31, 2008, representing an increase of $135.1 million over the same period in 2007. The favorable results are attributable to transportation rate increases that went into effect during 2008, together with higher volumes transported on our Liquids systems, partially offset by higher power, operating and administrative costs, and depreciation.

Operating revenue for the year ended December 31, 2008 increased by $225.0 million to $773.1 million from $548.1 million for the same period in 2007. The increase in operating revenue is due to the following:

- Increased average rates for transportation on all of our major systems as noted below;
- Higher delivery volumes on our Lakehead and North Dakota systems;
- Additional revenue resulting from higher crude oil prices associated with the allowance oil we receive in connection with our transportation services; and
- Additional contract storage fee revenue generated by our Mid-Continent storage terminal system.

Increases in average transportation rates on all three Liquids systems together with longer hauls contributed approximately $170.5 million of additional operating revenue. We filed new tariff rates in 2008 on our Lakehead system, effective April 1, 2008, to reflect the recent completion of four projects: (1) the Southern Access mainline expansion, (2) two Superior terminal tank projects, (3) two Griffith terminal tank projects and (4) the Clearbrook Manifold project. We also implemented new tariff rates on our North Dakota system, effective January 1, 2008, to reflect the completion of our North Dakota Phase V expansion. Additionally, we increased the average transportation rates on all three of our Liquids systems in connection with the annual index rate ceiling adjustment that went into effect July 1, 2008.

Average delivery volumes on our Lakehead system increased approximately 5.0 percent, to 1.620 million Bpd for the year ended December 31, 2008 from 1.543 million Bpd during the same period in 2007. This increase contributed an additional $22.8 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily derived from increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands.

Our transportation tariff allows 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, 2008 were substantially higher than the average prices for the same period of 2007. For example, the average price of West Texas Intermediate crude oil increased approximately 38 percent for the year ended December 31, 2008 as compared with the same period in 2007. As a result of the increase in crude oil prices, we experienced an approximate $18.6 million increase in allowance oil revenues.

Also contributing to the increase in revenues for the year ended December 31, 2008, was an approximately $8.7 million increase in contract storage and spot storage fees generated by our Mid-Continent storage terminal system from the additional storage tanks we placed in service during mid and late 2007. Across our Mid-Continent system, we added a net of seven storage tanks during 2007 contributing an additional 3.8 million barrels of capacity bringing the total storage capacity to approximately 16.7 million barrels and 106 tanks. This additional storage capacity is expected to provide ongoing fixed, variable, and spot storage revenue.

Operating and administrative expenses for the Liquids segment increased $33.3 million for the year ended December 31, 2008, compared with the same period in 2007. The increase in these costs is primarily attributable to the following:

- Additional workforce related costs for the operational, administrative, regulatory, and compliance support services necessary for our growing systems;
- Increased costs related to repair and maintenance activities;
- Unfavorable oil measurement adjustments as described below;
- Further costs incurred in connection with the crude oil release and fire on Line 3 of our Lakehead system; and
- Modest increases in property taxes due to favorable settlements of property tax assessments that we realized during the year ended December 31, 2007 which were not present for the same period in 2008.

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 incidents;
- Degradation resulting from mixing at the interface of our pipeline systems or within our terminals 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.

Power costs increased $23.7 million in the year ended December 31, 2008, compared with the same period in 2007, predominantly due to the higher delivery volumes coupled with higher utility rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas and coal costs associated with volatile pricing of these commodities.

The increase in depreciation expense of $32.9 million is attributable to the additional assets we have placed in service during 2007 and for the year ended December 31, 2008, including the Southern Access Expansion stage one assets that we placed in service during the second quarter of 2008 along with the assets placed into service on our North Dakota and Mid-Continent systems.

Other Matters

Spearhead Pipeline Acquisition

In May 2009, we purchased a portion of a crude oil pipeline system from CCPS Transportation, L.L.C., a wholly-owned subsidiary of our general partner, for approximately $75 million, representing the carrying value in the records of our general partner. The portion of the system, which we refer to as Spearhead North, includes approximately seven storage tanks and 75 miles of pipeline that our general partner reversed to provide northbound service from Flanagan, Illinois to Griffith, Indiana. The acquisition of Spearhead North complements the existing operations of our Lakehead system, as our newly-constructed Southern Access pipeline ends in Flanagan where it connects to Spearhead North.

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 Project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease became effective February 20, 2009, which was the in-service date for the light sour pipeline. The lease of Line 13 will be effective until the earliest of (i) July 1, 2010, (ii) upon the transfer of the Canadian portion of Line 13 from Enbridge Pipelines, Inc., or Enbridge Pipelines, to Enbridge Southern Lights LP, a wholly-owned subsidiary of Enbridge Pipelines or (iii) early termination of the lease. We are able to terminate the lease at any time during the term by providing Southern Lights with written notice, at which time we would be required to return Line 13 to Southern Lights. The costs associated with the lease are being recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow over the life of the transaction is expected to approximate zero. The exchange resulted in a $166.5 million increase in "Property, plant and equipment" 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. Subsequent to the initial exchange, an additional $5.8 million of costs were incurred by Southern Lights through December 31, 2009 that have been transferred to us through the capital account of our general partner, which are included in the $171.5 million cost presented above. 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.

Future Prospects for Liquids

Historically, western Canada has been a key source of oil supply serving U.S. energy needs. Canada's oil sands, one of the largest oil reserves in the world, are becoming an increasingly prominent source of supply. Combined conventional and oil sands established reserves of approximately 175 billion barrels compare with Saudi Arabia's proved reserves of approximately 260 billion barrels. The National Energy Board of Canada, or NEB, estimates that total Western Canadian Sedimentary Basin, or WCSB, production averaged approximately

2.5 million Bpd in 2009 and 2.4 million Bpd in 2008. Relative to recent years, development of the Alberta Oil Sands is expected to moderate due to declining demand and volatile commodity prices and it is unlikely that all announced and planned oil sands projects will proceed as planned. The Canadian Association of Petroleum Producers, or CAPP, in June 2009 estimated future production from the Alberta Oil Sands to grow steadily during the next 10 years, with an additional 1.4 million Bpd of incremental supply available by 2019, 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.

Crude oil price volatility in 2008 and 2009 has caused some oil sands producers to cancel or defer projects that were planned to commence over the next decade. Cancellations and project deferrals of oil sands projects are expected to temper the rate of growth over the next several years relative to prior forecasts. If the rate of crude oil production from the Western Canadian Sedimentary Basin declines, immediate need for new pipeline infrastructure will likely decline. In addition to our expansions, a competitor pipeline system is expected to be placed into service during 2010 to transport crude oil from Hardisty to Wood River and Patoka and to Cushing, with an initial capacity of 435,000 Bpd and an ultimate capacity of 590,000 Bpd. This competing pipeline, together with our Southern Access and Alberta Clipper expansions should provide sufficient pipeline capacity in the near-term to meet the demand for transportation of crude oil production derived from the Alberta Oil Sands. Therefore, further expansion activities in and around our liquids systems will primarily focus on additional storage opportunities in the Cushing region and further development of our North Dakota system.

Partnership Projects

Southern Access

We completed the second and final stage of our Southern Access Project and placed it into service on April 1, 2009. The related tolling surcharge has been adjusted to include costs of this phase of the expansion and became effective April 1, 2009. This stage provides additional upstream pumping capacity and a new pipeline from Delavan, Wisconsin to Flanagan. Completion of the total Southern Access Project created a 42-inch, 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system, which can be further expanded to 1.2 million Bpd with expenditures for additional pumping equipment. The commercial structure for this expansion is a cost-of-service based surcharge that has been added to the existing transportation rates. We anticipate that earnings before interest, income tax, depreciation and amortization expenses associated with this project will be approximately $230 million to $250 million annually in the first full year that both stages of the Southern Access Project are fully operational.

Alberta Clipper

The Alberta Clipper Project involves construction of a new 36-inch diameter pipeline from Hardisty to Superior, generally within or alongside our existing rights-of-way in the United States and Enbridge's existing rights-of-way in Canada. The Alberta Clipper Project will interconnect with our existing mainline system in Superior where it will provide access to our full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka and Cushing. The project will have an initial capacity of 450,000 Bpd, is expandable to 800,000 Bpd and will form part of the existing Enbridge system in Canada and our Lakehead system in the United States. The Alberta Clipper Project is a fully cost of service agreement with a return of 225 basis points over the NEB multi pipeline rate of return.

Construction on the Canadian segment of the Alberta Clipper Project was mechanically completed in December 2009, and remains on schedule to be ready for service on April 1, 2010. This segment has an estimated cost of $2.3 billion CAD, including allowance for funds used during construction (AFUDC), with expenditures to date totaling $2.1 billion CAD. As of January 2010, construction is approximately 90% complete on the United States segment, and it also remains on schedule to be ready for service by April 1, 2010. The cost of the United States segment is estimated at $1.3 billion, with expenditures to date totaling $0.9 billion. As announced in July

2009, Enbridge has committed to fund 66.67% of the United States segment of the Alberta Clipper Project through us and our subsidiaries. Similar to the Southern Access Project, the costs of the Alberta Clipper Project are expected to be recoverable through surcharges on mainline tolls in both Canada and the United States.

We are financing the $1.3 billion of expected construction costs for the United States portion of the project through a joint funding arrangement whereby our general partner and other affiliates of ours and Enbridge participate jointly in financing a portion of the construction project in return for an interest in approximately two-thirds of the earnings and cash flows. The joint funding arrangement also contemplates our issuance of additional term debt in one or more capital markets transactions, following the in-service date of the project, to refinance our initial debt financing of the project. Our general partner will also refinance its portion of its initial debt financing of the project on the same terms. We anticipate that the first full year earnings before interest, income tax, depreciation and amortization expenses resulting from operating this pipeline project will approximate $170 million, of which we will be entitled to approximately $57 million. We expect the increase in transportation rates associated with the Alberta Clipper Project to contribute to our revenues beginning in the second quarter of 2010.

For both the Canadian and United States segments of the Alberta Clipper Project, tariffs will be filed with the appropriate regulators to be effective on April 1, 2010, the date the project is expected to be ready for service. The tariff for the United States segment, and its effective date, will be filed on the basis of the Alberta Clipper U.S. Term Sheet, despite a petition filed in January 2010 by a shipper requesting the FERC to delay the tariff. Following that petition filing, several shippers filed interventions requesting to be part of the process. The Alberta Clipper U.S. Term Sheet was approved by CAPP on June 28, 2007 and by the FERC on August 28, 2008. We have reviewed and will respond to the shipper petition, which we believe to be without merit.

North Dakota

In December 2009, we completed an approximate $0.15 billion further expansion of our North Dakota system, which consists of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents, or DRA, that are injected into the pipeline. This expansion of our North Dakota system, referred to as Phase VI, increased system capacity to 161,000 Bpd from the 110,000 Bpd that was previously available. The related tolling surcharge has been adjusted to include costs of this phase of the expansion that became effective January 1, 2010. The commercial structure for this expansion is a cost-of-service based surcharge that was added to the existing transportation rates. The tolling methodology is similar to the structure being used on the recently completed Phase V expansion project and was approved by the FERC in October 2008.

Enbridge and Other Projects

Spearhead Pipeline

Enbridge completed construction on the 68,300 Bpd expansion of the Spearhead Pipeline to a capacity of approximately 193,300 Bpd on schedule in early 2009 and commenced operation in May 2009. The Spearhead pipeline is complementary to our Lakehead system as western Canadian crude oil is carried on our Lakehead system as far as Chicago and then transferred to the Spearhead pipeline.

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 10,000 miles of natural gas gathering and transmission pipelines;
- Nine natural gas treating plants and 22 natural gas processing plants, excluding inactive plants and including plants that we idle from time to time based on current volumes; and
- Trucks, trailers and railcars used for transporting NGLs, crude oil and carbon dioxide.

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 and amounts have been revised to exclude the results of our discontinued operations, which are discussed below in the section labeled *Other Matters.*

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Operating Results			
Operating revenues	$ 2,620.9	$ 4,515.7	$ 3,332.5
Cost of natural gas	2,091.5	3,864.0	2,919.1
Operating and administrative	288.6	306.4	241.2
Depreciation and amortization	123.0	107.5	82.4
Operating expenses	2,503.1	4,277.9	3,242.7
Operating Income	$ 117.8	$ 237.8	$ 89.8
Operating Statistics (MMBtu/d)			
East Texas	1,443,000	1,479,000	1,180,000
Anadarko	570,000	647,000	591,000
North Texas	387,000	395,000	348,000
Total	2,400,000	2,521,000	2,119,000

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 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. 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 of our consolidated financial statements beginning on page F-1 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 and condensate 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 condensate.
- 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. We are exposed to fluctuations in commodity prices in the near term on approximately 10 to 25 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. 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, 2009 compared with year ended December 31, 2008

Our Natural Gas segment contributed $117.8 million of operating income for the year ended December 31, 2009, a decrease of $120.0 million from the $237.8 million contributed in the corresponding period of 2008. The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the year ended December 31, 2009 as compared with the same period of 2008:

- A $121.4 million decrease resulting from $36.4 million of unrealized, non-cash, mark-to-market net losses from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with gains of $85.0 million for the same period of 2008;
- Lower average daily volumes of natural gas on our systems, as a result of lower natural gas production associated with reduced drilling by natural gas producers in the areas we serve;
- A decrease of approximately $9.2 million in revaluation losses associated with our inventories and in-kind natural gas imbalances due to less volatile commodity prices during the year of 2009 when compared to the same period in 2008;
- Improved system gain/loss experience resulting from the processes and quality improvements implemented;
- Hurricanes did not disrupt our operations in 2009 as they did in 2008; and
- Cost reduction measures we instituted in 2009 to address rising operating and administrative costs, partially offset by higher depreciation expense associated with our 2008 system growth.

Changes in the average forward and daily prices of natural gas, NGLs and condensate from December 31, 2008 to December 31, 2009, produced unrealized, non-cash, mark-to-market net losses of $36.4 million for the year ended December 31, 2009 from the derivatives that do not qualify for hedge accounting we use to economically hedge a portion of the natural gas, NGLs and condensate associated with our Natural Gas business.

The average forward and daily prices for natural gas were lower at December 31, 2009 in relation to prices at December 31, 2008, producing gains in our portfolio of natural gas derivatives, while the average forward and daily prices for NGLs and condensate were higher at December 31, 2009 than at December 31, 2008, producing losses. Comparatively, at December 31, 2008, the average forward and daily prices for both natural gas and NGLs were significantly lower than the prices at December 31, 2007, which produced $85.0 million of unrealized, non-cash, mark-to-market net gains for the derivative instruments we used to fix the price of the natural gas purchased for processing and for the derivatives we used to hedge the sales prices of a portion of the NGLs derived from processing natural gas.

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, 2009 and 2008:

	For the year ended December 31,	
	2009	2008
	(in millions)	
Hedge ineffectiveness	$ (0.7)	$ (0.1)
Non-qualified hedges	(35.7)	85.1
Derivative fair value gains (losses)	$ (36.4)	$ 85.0

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 are exposed to fluctuations in commodity prices in the near term on approximately 10 to 25 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our margins generally increase when the prices of these commodities are rising and generally decrease when the prices are declining. During the year ended December 31, 2009, NGL and condensate prices increased, while natural gas prices declined, creating a favorable environment for processing NGL and condensate. Comparatively, during the year ended December 31, 2008, commodity prices for NGL, condensate and natural gas experienced significant price erosion. The rapid decline in commodity prices during the year ended December 31, 2008, led to $6.4 million of revaluation losses with respect to our in-kind natural gas imbalances as well as $4.1 million of non-cash charges to reduce the cost basis of our natural gas inventory to fair market value. Although commodity prices were significantly lower for the year ended December 31, 2009, when compared to the same period in 2008, a rapid decline in commodity prices did not occur and as a result we did not incur similar revaluation losses and non-cash charges in the 2009 period.

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 most recently the Haynesville shale. During the year ended December 31, 2009, natural gas volumes on our systems decreased 4.8 percent resulting from declines in production and shut-in natural gas. Due to the significant decline in natural gas prices over the past year, producers have reduced drilling activity levels compared to 2008 and the number of approved drilling permits in Texas for the year ended December 31, 2009 has declined 52% from the same period in 2008. Existing active drilling rigs in the areas we serve have also declined 55% during the year ended December 31, 2009 from levels that existed in the corresponding period in 2008.

Although conditions in the overall commodities markets have stabilized when compared to the volatility that existed in 2008, natural gas rig counts remain below recent peak levels. Weak demand coupled with low commodity prices have resulted in lower volumes being transported on our systems. As commodity prices continue to stabilize, natural gas producers will likely increase drilling activity in the areas we serve. We are positioned to capitalize on any future increases in natural gas production, in large part due to the expansions we have completed. Another factor that could lead to more demand for our services is the recent discovery of the Haynesville Shale in western Louisiana and eastern Texas. The Haynesville Shale has the potential of being the largest natural gas discovery in the United States. If proven, the discovery could create more drilling activity around our East Texas system, increasing the demand for our services.

A variable element of our Natural Gas segment's operating income is derived from processing natural gas under keep-whole arrangements on our East Texas, North Texas and Anadarko systems. Operating income derived from keep-whole processing arrangements for the year ended December 31, 2009 was $68.3 million, representing a decrease of $13.0 million, or 16 percent, from the $81.3 million we produced for the same period in 2008. The favorable pricing environment that existed for NGLs and condensate for the year ended December 31, 2008 was less favorable for the same period in 2009, reducing the operating income we derive from keep-whole processing arrangements.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including varying qualities of natural gas in the streams gathered and processed through our systems, changes in weather, temperatures and variances in measurement that are inherent in metering technologies. During the year ended December 31, 2009 we recognized approximately $17.7 million fewer losses related to measurement than in the same period for 2008. We implemented processes and quality improvements to enhance the operating conditions on our natural gas systems, which continue to reduce the level of system gain/loss.

During the months from September to December 2008, we experienced operational disruptions to our onshore natural gas facilities as a result of hurricanes Gustav and Ike. Our facilities sustained minimal physical damage from the hurricanes, although some of our natural gas systems had lower throughput and revenues from the months of September to December 2008 due to the inability of third-party downstream facilities to receive deliveries of our natural gas and NGLs. These temporary disruptions curtailed our ability to gather unprocessed natural gas at our processing plants and transport natural gas to markets in the Texas and Louisiana regions. Approximately $11 million of lost revenue associated with the hurricanes occurred during the September to December 2008 timeframe. Hurricanes did not disrupt our natural gas operations during the year ended December 31, 2009.

Operating and administrative costs of our Natural Gas segment were $17.8 million lower for the year ended December 31, 2009 compared to the same period in 2008, primarily due to our implementation of enhanced cost reduction measures. Our efforts to closely monitor and reduce expenditures have yielded positive results by reducing the costs associated with material and supplies purchases, consolidating spend with particular vendors and lowering the costs for repairs and maintenance activities when compared to the year ended December 31, 2008. Our cost reduction measures included temporarily idling some of our processing and treating facilities in response to current economic conditions. The lower operating and administrative costs were partially offset by greater depreciation expense for our Natural Gas segment for the year ended December 31, 2009 as compared to the same period in 2008, as a result of the capital projects completed and placed into service in 2008.

Year ended December 31, 2008 compared with year ended December 31, 2007

Our Natural Gas segment contributed $237.8 million of operating income for the year ended December 31, 2008, an increase of $148.0 million from the $89.8 million contributed in the corresponding period of 2007. The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the year ended December 31, 2008 as compared with the same period of 2007:

- $85.0 million of unrealized, non-cash mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with losses of $59.0 million for the same period of 2007;
- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations;
- Reduced revenues of approximately $11 million associated with the impact of hurricanes Gustav and Ike in the third and fourth quarters of 2008, when third-party facilities downstream of our operations were damaged or without power. Physical damage to our facilities was minimal with certain of our natural gas assets incurring capital and operating costs of approximately $1 million for repairs. Our three major natural gas systems have been returned to pre-hurricane levels;

- Increased use of fee-based arrangements to compensate us for our services are at lower margins relative to contract structures that contain commodity price risk;
- Declines in the prices of natural gas and NGLs from July 2008 to December 31, 2008 decreased the value of our in-kind natural gas imbalance receivables and produced non-cash charges to reduce the cost basis of our natural gas inventory to net realizable value; and
- Increased workforce, repair and maintenance, materials and supplies, property taxes and depreciation associated with our system growth.

The operating income of our Natural Gas segment for the year ended December 31, 2008 was positively affected by unrealized non-cash, mark-to-market net gains of $85.0 million, representing an increase of $144.0 million from the $59.0 million of losses we recorded for the same period of 2007. During the second half of 2008, significant declines in the forward and daily market prices of natural gas, NGLs and condensate produced non-cash, mark-to-market net gains in our portfolio of derivative instruments. The declining price environment that was prevalent during the second half of 2008 was not present during most of the year ended December 31, 2007. We expect the net mark-to-market gains to be offset when the related physical transactions are settled.

Despite the substantial fluctuations in commodity prices during 2008, an overall favorable pricing environment contributed to higher average prices for the sale of natural gas and NGLs we receive as in-kind payment for our services. The improved margins were also enhanced by an approximate 10% increase in average daily volumes on our natural gas systems. The increase in average daily volume of our Natural Gas business is directly attributable to the significant investments we have made to expand the capacity and service capability of our systems. We completed the following projects during the years ended December 31, 2008 and 2007, which have contributed to the increase in average daily volumes and operating results of our major natural gas systems:

- In May 2008 our expansion of the Aker treating plant on our East Texas system was completed and placed into service adding 125 million cubic feet per day, or MMcf/d, of treating capacity.
- The $655 million expansion and extension of our East Texas natural gas system, referred to as the Clarity project, is substantially complete and includes:
  - The Goodrich compressor station was constructed and placed into service in December 2008;
  - A 36-inch diameter pipeline segment that extends from Kountze to Orange County was placed into service in July 2008;
  - A 20-inch segment from Orange County to a downstream interconnect near Beaumont enabling deliveries into the interconnect was placed into service in December 2008;
  - Construction of the Orange County compressor station is nearly complete and is expected to be placed into service in February 2009;
  - A 36-inch diameter pipeline that extends from Goodrich to Kountze was completed in October 2007, which enables deliveries into a major interstate pipeline;
  - A 36-inch diameter pipeline that extends from an interconnect with our existing pipeline at Bethel to Crockett, Texas was completed and placed into service in late July 2007;
  - A 20-inch diameter pipeline in close proximity to our Marquez treating facility was completed and placed into service in June 2007;
  - A 24-inch diameter pipeline that runs from the Marquez treating facility to Crockett and the 36-inch diameter pipeline that runs from Crockett to Goodrich, Texas were both completed and placed into service in late March 2007; and
  - The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed into service in March 2007.

- ➢ We expect to finish the final compression station during the first quarter of 2009. The total added capacity related to this project when completed will approximate 700 MMcf/d.

- In the first quarter of 2008 we completed construction of a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas.
- Construction of the Weatherford gas processing facility within our North Texas system was completed in September 2007 with a processing capacity of approximately 35 MMcf/d. At the end of 2007, additional processing capacity was added to the Weatherford processing facility to increase its capacity from 35 MMcf/day to 75/MMcf/day.
- In the latter half of 2007, we completed construction of three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specifications. These facilities have a cumulative capacity of 550 MMcf/d and obtain a significant portion of their revenues from fees rather than keep-whole processing or percentage-of-liquids revenues.
- Construction of the Hidetown processing facility on our Anadarko system with approximate capacity of 120 MMcf/d was completed and placed into service at the end of April 2007.
- During the second quarter of 2007, we refurbished our Zybach processing plant to address operational inefficiencies experienced by the plant. As a result of the service and repairs, processing volumes were restored to expected levels.

The processing margins we derive from processing natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems declined 25 percent for the year ended December 31, 2008 in relation to the same period of 2007. Operating income derived from keep-whole processing arrangements for the year ended December 31, 2008 was $81.3 million, representing a decrease of $27.5 million from the $108.8 million we produced for the same period in 2007. During the last half of 2008, NGL and crude oil prices began to decline faster than natural gas prices, which have the effect of reducing revenue we derive from our processing assets. In addition we continue to experience a trend of replacing or renegotiating some of our existing keep-whole contracts with percentage of liquids, or POL, type contracts and other similar arrangements. This trend should reduce our exposure to the commodity price spread between natural gas and NGLs for the portion of the operating income we derive from processing natural gas under keep-whole arrangements.

During the months from September to December 2008, we experienced operational disruptions to our natural gas facilities as a result of hurricanes Gustav and Ike. Our facilities in Texas sustained minimal physical damage from the hurricanes, although some of our natural gas systems had lower throughput and revenues for the months of September through December due to the inability of third-party downstream facilities to receive deliveries of our natural gas and NGLs. These temporary disruptions curtailed our ability to gather unprocessed natural gas at our processing plants, transport natural gas to markets, and to access natural gas liquids we own at third party facilities held under force majeure. Our lost revenue associated with the hurricanes approximates $11 million. We did not recover any of these losses through insurance. The majority of our facilities returned to normal operation by the end of September 2008.

As a result of the significant price erosion in daily natural gas prices in the second half of 2008, we recorded $6.4 million of revaluation losses with respect to our in-kind natural gas imbalances. NGL prices also experienced similar declines in prices which required us to recognize $4.1 million of charges to reduce the cost basis of our NGLs.

Operating and administrative costs of our Natural Gas segment were $65.2 million greater for the year ended December 31, 2008 compared to the same period in 2007, primarily as a result of increased workforce-related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our general partner charges us for the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of pipeline expansions across the areas we serve.

Materials, supplies and other costs along with repair and maintenance costs were higher predominantly due to the increase in volumes and expansion of our natural gas systems. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our natural gas systems. We expect workforce related costs in addition to materials, supplies and other costs to increase in relation to the increase in volumes of natural gas services we provide.

Depreciation expense for our Natural Gas segment was higher for the year ended December 31, 2008 as compared to the same period in 2007, as a result of the capital projects completed and placed into service throughout 2008 and the last quarter of 2007.

In September 2008, we acquired the transportation assets of Petron, a trucking company located in Alexandria, Louisiana, for $7.7 million in cash. The acquisition was necessitated by the growing supply of NGLs, crude oil and carbon dioxide from our processing facilities, as well as the need to better serve our U.S. Gulf Coast customers. The operations of the newly acquired truck fleet increased our operating and administrative expenses for the fourth quarter of 2008.

Future Prospects for Natural Gas

During 2009, the volatility that existed in the capital markets required us to implement a less aggressive capital program in our natural gas business. We will continue to maintain a focus on internal growth programs, even though the disruption to capital markets has begun to subside. Also, if opportunities should arise for us to expand our natural gas systems through accretive acquisitions in or near the areas we serve, we will pursue them on a selected basis.

The Haynesville Shale has been referred to as one of the largest natural gas fields in the continental United States. Drilling activity has been increasing over the last two years, as initial discoveries have yielded high production rates and low drilling costs relative to other areas in the United States. This production area is defined as being within western Louisiana and east Texas areas, with a substantial amount of the Texas production overlaying our existing natural gas assets. This has enabled us to pursue new development opportunities, such as the Shelby County Loop project, even though overall capital spending by producers has been reduced. We are continuing to look for more opportunities to leverage the developing Haynesville Shale area, as we believe we are well positioned with the scale of our East Texas assets.

Partnership Projects

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. In addition, we plan to construct a large diameter lateral pipeline from Shelby County to Carthage, expanding our recently completed Shelby County Loop expansion. The expansion into the Haynesville Shale area is expected to increase our capacity in our East Texas system to 900 MMcf/d.

Shelby County Loop and Compression

We commenced construction during the third quarter of 2008 to add compression at the Carthage Hub and on the Shelby County lateral sections of our East Texas system. We have also initiated construction to increase the capacity of the East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. During the second quarter of 2009, construction on the approximately $60 million project was substantially completed with additional compression added in the third quarter of 2009.

Enbridge Projects

LaCrosse Pipeline

The proposed interstate natural gas pipeline, known as the LaCrosse Pipeline, will run from our Carthage Hub in Panola County, Texas to the Sonat Pipeline in Washington Parish, Louisiana. The 300-mile pipeline, which is expected to have a capacity of at least one billion cubic feet per day, is designed to provide an outlet for increasing supplies of natural gas originating in the East Texas and Fort Worth producing basins and in the growing Haynesville Shale Play. The pipeline would interconnect with pipelines accessing the Perryville, Louisiana Hub as well as Louisiana industrial markets and pipelines serving southeastern U.S. markets. The pipeline would provide our customers with additional markets and options when transporting their natural gas. In May 2009, Enbridge conducted a successful non-binding open season for the proposed pipeline. The next stage of the project involves confirming customer interest and the expected cost of the new construction.

Other Matters

2009 Asset Disposition

In November 2009, we sold our non-core natural gas pipeline assets located predominantly outside of Texas for cash totaling approximately $150.8 million excluding any subsequent settlement for working capital as provided in the sale agreement. The natural gas pipeline assets we sold include primarily intrastate and interstate natural gas transmission systems and related facilities, which serve onshore and offshore markets in the southeastern United States and along the Gulf Coast. The natural gas pipeline assets include over 1,400 miles of pipeline with diameters ranging from 2 to 30 inches. The areas in which the natural gas pipeline assets operate are not strategic to the ongoing central operations of our core Natural Gas segment assets.

The following table presents the operating results of the non-core natural gas pipeline assets that we sold in November 2009. We derived the results from historical financial information and have excluded these amounts from our discussion of the operating results of our Natural Gas business. Included in the 2009 operating results are net charges of $64.5 million which represent a charge for $66.1 million we recorded as an impairment to reduce the carrying value of the assets to our estimate of the fair value of these assets, partially offset by a $1.6 million reduction to this amount we realized upon the completion of the sale.

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Operating revenue	$ 173.6	$ 367.9	$ 290.9
Operating expenses			
Cost of natural gas	143.3	325.0	251.3
Operating and administrative	19.1	22.1	25.5
Depreciation and amortization	11.6	13.5	13.7
	174.0	360.6	290.5
Operating income (loss)	(0.4)	7.3	0.4
Interest expense	—	—	1.2
Other income (expense)	(64.5)	1.0	—
Income (loss) from discontinued operations	$ (64.9)	$ 8.3	$ (0.8)

2007 Asset Disposition

In November 2007, we sold our Kansas pipeline system, or KPC, to an unrelated party for $133 million in cash, subject to adjustments for working capital items. KPC is an interstate natural gas transmission system, which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline ranging in diameter from 4 to 12 inches, along with three compressor stations. KPC represented a business within our Natural Gas segment that we did not consider strategic to the ongoing central operations of our core Natural Gas segment assets. The operating results of the KPC system were not material to our consolidated operating results or those of our Natural Gas segment for the year ended December 31, 2007. We recognized a gain of $32.6 million on the sale of KPC, which is presented in income from discontinued operations.

Marketing

The following table sets forth the operating results for the Marketing segment assets for the periods presented and amounts have been revised to exclude the results of our discontinued operations related to the sale of non-core natural gas assets in November 2009, as discussed in the section labeled *Natural Gas*:

	For the year ended December 31,		
	2009	**2008**	**2007**
		(in millions)	
Operating Results			
Operating revenues	$ 2,139.1	$ 4,609.9	$ 3,291.5
Cost of natural gas	2,089.3	4,590.5	3,256.9
Operating and administrative	6.4	10.1	8.0
Depreciation and amortization	1.4	1.6	1.6
Operating expenses	2,097.1	4,602.2	3,266.5
Operating Income (Loss)	$ 42.0	$ 7.7	$ 25.0

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 requiring 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 last several years, which we can use to transport natural gas to primary markets where it can be sold at more favorable prices.

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 "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 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 offset 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 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 withdrawn 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 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.

Marketing 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, 2009 compared with year ended December 31, 2008

The operating income we derive from the sale of natural gas declined as a result of narrowing of the differences in the prices of natural gas between the prices we pay to purchase natural gas and the prices we receive for the natural gas we sell to customers for the year ended December 31, 2009 as compared with the same period in 2008. Although the volumes that our Marketing business received from our Natural Gas segment assets remained relatively stable when compared to the year ended December 31, 2008, the revenue and related margin from the sale of those natural gas volumes declined. The volatility existing in the overall commodities markets during the year ended December 31, 2008, resulted in more opportunities for us to benefit from differences between the purchase and sales prices of natural gas, which resulted in higher operating income. The less volatile pricing environment existing during the year ended December 31, 2009 reduced the differences between the purchase and sales prices of natural gas, which in turn reduced our operating income for the period.

The operating results of our Marketing segment for the year ended December 31, 2009 were positively affected by unrealized, non-cash, mark-to-market net gains of $20.7 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. The non-cash, mark-to-market net gains during the year ended December 31, 2009 resulted from the continued narrowing of natural gas purchase and sales prices between market centers, which benefited our hedged transportation positions. During the year ended December 31, 2008, increases in the forward and daily market prices of natural gas produced $16.2 million of non-cash, mark-to-market net losses in our portfolio of derivative instruments as a result of the lower fixed price hedged transportation positions we had on our natural gas purchases and sales. We expect all mark-to-market net gains to be offset when the related physical transactions are settled.

Operating and administrative costs for our Marketing segment were $3.7 million lower for the year ended December 31, 2009 compared to the same period in 2008. Consistent with our Natural Gas business, our cost reduction initiatives implemented during 2009 resulted in lower operating and administrative costs.

Year ended December 31, 2008 compared with year ended December 31, 2007

Operating income of our Marketing segment declined to $7.7 million for the year ended December 31, 2008 from income of $25.0 million for the corresponding period in 2007. Included in the operating income for the year ended December 31, 2008 are approximately $16.2 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting under authoritative accounting guidance, compared to the $3.8 million of unrealized mark-to-market net losses for the comparable period of 2007. The unrealized, mark-to-market net losses for the year ended December 31, 2008 result from decreases in the forward and daily market prices of natural gas from December 31, 2007. We expect the mark-to-market net losses to be offset when the related physical transactions are settled.

Operating income for the year ended December 31, 2008 was also negatively affected by non-cash charges of $7.5 million we recorded to reduce the cost basis of our natural gas inventory to net realizable value, which is $3.2 million more than the $4.3 million non-cash charge we recorded for the same period of 2007. Natural gas and NGL prices declined significantly from the record highs experienced in July of 2008. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

The operating and administrative expenses of our Marketing business are slightly more for the year ended December 31, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

Corporate

Year ended December 31, 2009 compared with year ended December 31, 2008

Interest expense was $228.6 million for the year ended December 31, 2009, compared with $180.6 million for the corresponding period in 2008. The increase is primarily the result of a higher weighted average outstanding debt balance in 2009 as compared with 2008, along with higher commitment fees we incurred to establish the 364-day credit facilities that we terminated in December 2009, along with increased amortization of debt issuance cost. The debt issuances that impacted the entire year ended December 31, 2009 are as follows:

- $400 million of our 6.5% Senior Notes issued in April 2008;
- $400 million of our 7.5% Senior Notes issued in April 2008; and
- $500 million of our 9.875% Senior Notes issued in December 2008.

Our weighted average interest rate was 6.89% for the year ended December 31, 2009, as compared with 6.23% for the same period in 2008.

We are exposed to interest rate risk associated with changes in interest rates on our variable rate debt. Our variable interest rate borrowing cost is 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 a defined credit spread. In order to mitigate the negative effect high interest rates have on our cash flows, we purchased interest rate caps, which establish a ceiling averaging approximately 1.12% on the interest rates we pay on up to $400 million of our variable rate indebtedness through January 2011. The interest rate caps do not qualify for hedge accounting and, as a result, the fair values of these derivative financial instruments are recorded as assets or liabilities on our consolidated statements of financial position with the changes in fair value recorded as corresponding increases or decreases in "Interest expense" on our consolidated statements of income. For the year ended December 31, 2009, we recorded $0.5 million of unrealized, non-cash, mark-to-market net gains associated with the changes in fair value of these derivatives that resulted from the increase in interest rates from the May 2009 date these derivative financial instruments were purchased to December 31, 2009.

Further contributing to the increase in interest expense is the $10.4 million decrease in interest capitalized to our construction projects for the year ended December 31, 2009 as compared to the same period in 2008. For the years ended December 31, 2009 and 2008, our interest cost is comprised of the following:

	For the year ended December 31, 2009	For the year ended December 31, 2008
	(in millions)	
Interest expense	$ 228.6	$ 180.6
Interest capitalized	30.6	41.0
Interest cost incurred	$ 259.2	$ 221.6
Interest paid	$ 241.5	$ 193.1

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. These taxes on our net income are generally borne by our unitholders through the allocation of taxable income.

The tax structures that exist in Michigan and Texas impose taxes that are based upon many but not all items included in net income. Our income tax expense is $8.5 million and $7.0 million for the years ended December 31, 2009 and 2008, respectively, which we computed by applying a 0.51% Texas state income tax rate to modified gross margin and a 0.12% Michigan state income tax rate to net income and modified gross receipts. Our income tax expense represents a 2.6% and 1.7% effective rate as applied to pretax income for December 31, 2009 and 2008, respectively.

Year ended December 31, 2008 compared with year ended December 31, 2007

Interest expense was $180.6 million for the year ended December 31, 2008, compared with $99.8 million for the corresponding period in 2007. The increase is primarily the result of a higher weighted average debt balance associated with the debt issuances in 2008 discussed above under our analysis of the year ended December 31, 2009 compared with December 31, 2008 and the following issuances in 2007:

- $400 million of our Junior Subordinated Notes in September 2007; and
- $200 million of our Zero Coupon Senior Notes in August 2007.

Further contributing to the increase in interest expense is the $6.4 million decrease in interest capitalized to our construction projects for the year ended December 31, 2008 from the same period in 2007. For the years ended December 31, 2008 and 2007, our interest cost is comprised of the following:

	For the year ended December 31, 2008	For the year ended December 31, 2007
	(in millions)	
Interest expense	$ 180.6	$ 99.8
Interest capitalized	41.0	47.4
Interest cost incurred	$ 221.6	$ 147.2
Interest paid	$ 193.1	$ 125.8

Our income tax expense is $7.0 million and $5.1 million for the years ended December 31, 2008 and 2007, respectively, which we computed by applying a 0.50% Texas state income tax rate to modified gross margin and a 0.10% Michigan state income tax rate to modified gross receipts. Our income tax expense represents a 1.7% and 2% effective rate as applied to pretax book income for December 31, 2008 and 2007, respectively.

Other Matters

Joint Funding Arrangement for Alberta Clipper Project and Regulatory Accounting

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Project, with several of our affiliates and affiliates of Enbridge. Enbridge, through our general partner, is funding approximately two-thirds of both the debt financing and equity requirement for the project in exchange for a 66.67 percent ownership interest in the Alberta Clipper Project and a return of approximately two-thirds of the earnings and cash flows. For our 33.33 percent ownership of the Alberta Clipper Project, we are funding approximately one-third of the debt financing and required equity of the project, for which we will be entitled to approximately one-third of the project's earnings and cash flows. As a result of this joint funding arrangement, 66.67 percent of earnings associated with the Alberta Clipper Project are attributable to our general partner and presented as "Noncontrolling interest" in our consolidated statements of income and consolidated statement of financial position. For further details on our Alberta Clipper joint funding arrangement please refer to the *Capital Resources—Joint Funding Arrangement* discussion below under *Liquidity and Capital Resources.*

In August 2009, we applied the provisions of regulatory accounting to our Alberta Clipper Project when the project received its Presidential Border Crossing Permit from the U.S. Department of State. In conjunction with our application of the provisions of regulatory accounting, we recorded an allowance for equity during construction, referred to as AEDC, of $12.6 million, for the year ended December 31, 2009. We also recorded an allowance for interest during construction, or AIDC, that was $4.5 million for the year ended December 31, 2009. These amounts together represent the $17.1 million in earnings of the Alberta Clipper Project for the year ended December 31, 2009, of which we have allocated $11.4 million to noncontrolling interest, representing our general partner's 66.67 percent ownership interest in the project.

Environmental Legislation

The United States Congress is actively considering legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. In addition, other federal, state and regional initiatives to regulate greenhouse gas emissions are under way. We are monitoring federal and state legislation to assess the potential impact on our operations.

LIQUIDITY AND CAPITAL RESOURCES

As computed in the following table, we had in excess of $1.0 billion of liquidity at December 31, 2009 to meet our ongoing operational, investment and financing needs, excluding the $130.3 million we have available from our general partner to fund the Alberta Clipper Project, as noted below.

	(in millions)
Availability under Credit Facility	$ 387.6
Available under Enbridge (U.S.) Credit Agreement	500.0
Cash and cash equivalents	143.6
Total	$ 1,031.2

General

Our primary operating cash requirements consist of normal operating expenses, core maintenance activities, distributions to our partners and payments associated with our derivative activities. We expect to fund our current and future short-term cash requirements from our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Second Amended and Restated Credit Agreement, which we refer to as the Credit Facility.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses. Our need for investment capital to fund our expansion projects, make acquisitions of new assets and businesses and to retire maturing or callable debt obligations is expected to be funded from several sources. We anticipate initially funding long-term cash requirements for expansion projects and acquisitions first from operating cash flows, second, from borrowings under our Credit Facility, third from borrowings under our credit agreement with Enbridge (U.S.) Inc., or Enbridge U.S., a wholly-owned subsidiary of Enbridge, and, as needed, from other potential sources of capital. Likewise, we anticipate initially retiring our maturing debt with similar borrowings on these existing facilities and possibly debt and equity financings through the capital markets. We expect to obtain permanent financing 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.

Enbridge, as the ultimate parent of our general partner, has been and continues to be supportive of our efforts in executing our capital expenditure program as some of these projects are beneficial to our mutual customers and operational asset bases. In addition to Enbridge's recent liquidity support and investment through our general partner, Enbridge has the capacity to provide further support in the form of participation in public and private equity transactions, and other non-traditional forms of investments in our operations.

Capital Resources

Joint Funding Arrangement

As noted above, we have entered a joint funding arrangement with our general partner and other affiliates of ours and Enbridge to finance construction of the United States portion of our $1.3 billion Alberta Clipper Project. We are funding approximately one-third of the debt and equity financing required for the project. We and our general partner each have a right of first refusal on the other's investment in the project and we retain the right to fund up to 100 percent of any expansion of the project. We expect to fund our portion of the base project using our credit facility and a future capital markets debt transaction.

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 projects. We have issued a balanced combination of debt and equity securities to fund our expansion projects. Our planned internal growth projects will require additional permanent capital and continue to require us to bear the cost of constructing these new 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.

The following table presents historical information about offerings of our units, which represent limited partner interests, since January 2007:

Issuance Date	Class of Limited Partnership Interest	Number of units Issued	Offering Price per 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)				
2009						
October	Class A	21,245	$ 47.070	$ 1.0	$ —	$ 1.0
2008						
December[3]	Class A	16,250,000	$ 30.760	$ 499.6	$ 10.2	$ 509.8
March	Class A	4,600,000	49.000	217.2	4.6	221.8
2008 Totals		20,850,000		$ 716.8	$ 14.8	$ 731.6
2007						
May	Class A	5,300,000	$ 58.000	$ 301.9	$ 6.1	$ 308.0
April	Class C	5,930,792	53.113	314.4	6.4	320.8
2007 Totals		11,230,792		$ 616.3	$ 12.5	$ 628.8

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

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

(3) All Class A common units from the December 2008 issuance were issued to our General Partner.

In addition to the proceeds we have received from offerings of our limited partner interests, we have also generated additional equity capital from the in-kind distributions we have made to holders of our i-units and Class C units. The Class C units were converted into Class A common units on a one-for-one basis in October 2009. The following table presents cash we have retained in our business since January 2007 from the in-kind distribution of additional i-units and Class C units:

Distribution Payment Date	Retained for i-units	Retained for Class C units	Retained from General Partner	Total Cash Retained
2009				
November 13	$ 15.9	$ —	$ 0.3	$ 16.2
August 14	15.5	20.7	0.7	36.9
May 15	15.1	20.1	0.7	35.9
February 13	14.6	19.5	0.7	34.8
	$ 61.1	$ 60.3	$ 2.4	$ 123.8
2008				
November 14	$ 14.3	$ 18.9	$ 0.7	$ 33.9
August 14	13.9	18.6	0.7	33.2
May 15	13.1	17.5	0.6	31.2
February 14	12.9	17.2	0.6	30.7
	$ 54.2	$ 72.2	$ 2.6	$ 129.0
2007				
November 14	$ 12.7	$ 16.8	$ 0.6	$ 30.1
August 14	12.1	16.2	0.6	28.9
May 15	11.9	15.9	0.6	28.4
February 14	11.7	10.2	0.5	22.4
	$ 48.4	$ 59.1	$ 2.3	$ 109.8

Although fixed income markets in the United States and around the world have become less constrained over the past year, lending conditions in the global economy are still below levels experienced in prior years. While the credit ratings assigned to our senior unsecured debt securities by the nationally recognized statistical ratings organizations remain at "investment grade," we may from time to time experience difficulty accessing the long-term credit markets due to prevailing market conditions. Additionally, existing constraints in the credit markets may increase the rates we are charged for utilizing these markets.

Available Credit

Historically our two primary sources of liquidity have been the commercial paper market and our Credit Facility. From November 2008 until July 2009 we were unable to access the commercial paper market due to a downgrade in our short-term credit rating by Standard and Poor's to A-3 from A-2 and used our Credit Facility as our primary source of liquidity. In July 2009, Standard and Poor's revised their ratings on our short-term credit to A-2 from A-3, which allows us to once again make use of our $600 million commercial paper program, depending on market conditions. We will continue to use our Credit Facility primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions and access the commercial paper market for similar temporary financing as economic conditions warrant. In addition to our Credit Facility and commercial paper program, we have available credit for borrowing up to $500 million under a revolving credit agreement with Enbridge (U.S.) Inc.

Outstanding Indebtedness

The following table presents the components of our outstanding indebtedness:

	December 31, 2009	December 31, 2008
	(in millions)	
Current maturities of long-term debt:		
9.150% First Mortgage Notes	$ 31.0	$ 31.0
4.000% Senior Notes due 2009	—	175.0
5.358% Senior unsecured zero coupon notes due 2022	—	214.7
	$ 31.0	$ 420.7
Current loans from General partner and affiliates:		
A1 Credit agreement	$ 269.7	$ —
Long-term debt:		
Credit Facility	765.0	166.8
9.150% First Mortgage Notes	31.0	62.0
7.900% Senior Notes due 2012[(1)]	100.0	100.0
4.750% Senior Notes due 2013	200.0	200.0
5.350% Senior Notes due 2014	200.0	200.0
5.875% Senior Notes due 2016	300.0	300.0
7.000% Senior Notes due 2018[(1)]	100.0	100.0
6.500% Senior Notes due 2018	400.0	400.0
9.875% Senior Notes due 2019	500.0	500.0
7.125% Senior Notes due 2028[(1)]	100.0	100.0
5.950% Senior Notes due 2033	200.0	200.0
6.300% Senior Notes due 2034	100.0	100.0
7.500% Senior Notes due 2038	400.0	400.0
8.050% Junior subordinated notes due 2067	400.0	400.0
Unamortized discount	(4.8)	(5.4)
	$ 3,791.2	$ 3,223.4
Long-term loans from General partner and affiliates:		
8.400% Note payable to affiliate	$ —	$ 130.0

(1) Debt of Enbridge Energy, Limited Partnership, one of our operating subsidiaries.

Credit Facility

Our Credit Facility is a revolving term facility that matures in April 2013 and has a maximum principal amount of credit available to us at any one time of $1,167.5 million. The Credit Facility allows us to request increases in the maximum principal amount of credit available at any one time from $1,167.5 million to $1.4 billion through an accordion feature. We pay interest on the amounts outstanding at variable rates equal to a "Base Rate" or a "Eurodollar Rate" as defined in the Credit Facility. In the case of Eurodollar Rate loans, an additional margin is charged which varies depending on our credit rating and the amounts drawn under the Credit Facility. We are also charged a facility fee on the entire amount of the Credit Facility, regardless of the amount drawn, which also varies depending on our credit rating. We continue to use our Credit Facility to provide short-term financing for our operations and capital expansion programs.

On March 31, 2009, we amended our Credit Facility to remove Lehman Brothers Bank, FSB, which we refer to as Lehman BB, as a lender, which effectively reduced the amounts available to us under our Credit Facility. The removal of Lehman BB permanently reduced both the amount we may borrow under the terms of our Credit Facility to $1,167.5 million as well as the number of committed lenders to 13. The amendment to our Credit Facility did not result in any changes to the pricing, fees or other commercial terms.

At December 31, 2009, we had $765.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.54% and outstanding letters of credit totaling $14.9 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the balance of our outstanding letters of credit.

At December 31, 2009, we could borrow $387.6 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$ 1,167.5
Less: Amounts outstanding under Credit Facility	765.0
Balance of letters of credit outstanding	14.9
Total amount we could borrow at December 31	$ 387.6

Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.25 to 1.0 for periods ending on or before March 31, 2010 and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. At December 31, 2009, our leverage ratio as defined under the Credit Facility was approximately 3.43. 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.

Commercial Paper Program

We have an established commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We generally access the commercial paper market to provide temporary financing for our operating activities, capital expenditures and acquisitions. At December 31, 2009 and 2008, we had no commercial paper outstanding.

First Mortgage Notes

The First Mortgage Notes are collateralized by a first mortgage on substantially all of the property, plant and equipment of the OLP, and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. The First Mortgage Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness by the OLP, including compliance with certain debt issuance tests. We were in compliance with these covenants at December 31, 2009. We do not believe these issuance tests will negatively affect our ability to access the credit markets to finance future expansion projects. Under the First Mortgage Notes Agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash for the immediately preceding calendar quarter. If we repay the Notes prior to their stated maturities, the First Mortgage Note Agreements provide for the payment of a redemption premium by us.

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 million of senior notes issued by the 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 as presented in the table above. Our Senior Notes do not contain any covenants restricting us from issuing additional indebtedness. 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, 2009.

The OLP, our operating subsidiary that owns the Lakehead system, has $300 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 as set forth in the table above. 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, 2009.

In January 2009, we repaid at face value $175.0 million in principal amount of our 4.0% Senior Notes that matured on January 15, 2009.

In December 2008, we issued and sold $500 million in principal amount of our 9.875% senior notes due March 1, 2019. We granted the holders of our Senior Notes due 2019 an option to require 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. We received net proceeds from the offering of approximately $496.5 million after underwriters' discounts and commissions, and payment of offering expenses. We used the proceeds to repay a portion of our outstanding Credit Facility borrowings that we use to finance our capital expansion projects and to repay $25 million of our Senior Notes maturing on January 15, 2009.

In April 2008, we issued and sold in a private offering $400 million in principal amount of our 6.5% Notes due April 15, 2018 and $400 million in principal amount of our 7.5% Notes due April 15, 2038, which we collectively refer to as the Notes. We received net proceeds from the offering of approximately $790.2 million after initial purchasers' discounts and payment of offering expenses. We used a portion of the proceeds we received from this offering to repay outstanding issuances of commercial paper and borrowings under our Credit Facility that we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds which we later used to fund additional expenditures under our capital expansion programs. In August 2008, we completed the offers to exchange all of the Notes, which had not been registered under the Securities Act of 1933, as amended (the "Securities Act"), for notes with identical terms that had been registered under the Securities Act. We subsequently received tenders for $395 million in aggregate principal amount of our outstanding $400 million of 6.50% Series A Notes due 2018, which we exchanged for $395 million of our 6.50% Series B Notes due 2018. We also received tenders for all $400 million in aggregate principal amount of our 7.50% Series A Notes due 2038, which we exchanged for $400 million of our 7.50% Series B Notes due 2038.

Zero Coupon Senior Notes

In August 2009, we repaid the holder of our senior, unsecured zero coupon notes due 2022 the full amount of the outstanding balance of approximately $222.3 million. The amount repaid includes $22.3 million of interest that we accreted to the original $200 million of principal of the zero coupon notes, including approximately $7.6 million of interest that we accreted during the year ended December 31, 2009.

Junior Subordinated Notes

The Junior Subordinated Notes, which we refer to as the Junior Notes, consists of our 8.05% fixed/floating rate, unsecured, long-term junior subordinated notes due 2067, with a principal amount outstanding of $400 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.

Indebtedness to Affiliates

Hungary Note Payable

In November 2009, we repaid $130.0 million of our outstanding notes payable to Enbridge Hungary Ltd., an affiliate of our general partner (the "Hungary Note"). At December 31, 2009 we had no amounts outstanding under the Hungary Note, while at December 31, 2008 there was $130.0 million outstanding. The Hungary Note bore interest at a fixed rate of 8.4% per annum that was payable semi-annually in June and December of each year through its maturity in December 2017.

EUS Credit Agreement

In December 2007, we entered into an unsecured revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge, referred to as the EUS Credit Agreement. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Second Amended and Restated Credit Agreement as discussed above. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Second Amended and Restated Credit Agreement. At December 31, 2009, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use.

364-day Credit Facilities

In April 2009, we entered into two unsecured and non-guaranteed revolving credit facility agreements totaling $350 million for funding our general activities and working capital, which we refer to as the 364-day Credit Facilities. On December 10, 2009, we terminated the 364-day Credit Facilities in accordance with the credit facility agreements and without penalty.

Credit Ratings

The following table reflects the ratings that have been assigned to our debt and the debt of our wholly-owned subsidiary, Enbridge Energy, Limited Partnership at December 31, 2009:

	Standard & Poor's	Moody's	Dominion Bond Rating Service
Enbridge Energy Partners, L.P.			
Outlook	Stable	Stable	Stable
Corporate	BBB	Baa2	NR
Commercial Paper	A-2	P-2	R-2(middle)
Medium Term Notes & Unsecured Debentures	BBB	Baa2	BBB
Junior subordinated debt	BB+	Baa3	BB(high)
Enbridge Energy, Limited Partnership			
Outlook	Stable	Stable	NR
Senior secured	BBB+	NR	NR
Senior unsecured	BBB	Baa1	NR

NR—No rating is available

Dominion Bond Rating Service, S&P and Moody's have maintained their BBB and Baa2 rating, respectively, with recently upgraded stable outlooks. The stable outlooks reflect the credit agencies' views that our financial profile is on par with those of our similarly rated peers, but that this financial profile is enhanced to a degree by our low business risk profile that stems from our highly regulated and/or contracted liquids and natural gas systems and our strategy of hedging a significant portion of our commodity exposure. Further, the stable outlooks reflect each credit rating agency's recognition of our ability to finance our organic growth capital expenditure program with the assistance of our general partner, Enbridge and its affiliates. The credit rating agencies upgraded their outlook from negative to stable once we announced the completion of our Alberta Clipper Joint Funding Arrangement.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2009:

	2010	2011	2012	2013	2014	Thereafter	Total
				(in millions)			
Long-term debt and notes payable to affiliates	$ 300.7	$ 31.0	$ 600.0	$ 965.0	$ 200.0	$ 2,000.0	$ 4,096.7
Purchase commitments(1)	248.7	—	—	—	—	—	248.7
Power commitments(2)	3.5	0.8	0.7	—	—	—	5.0
Operating leases	14.6	14.8	12.0	9.5	9.4	52.8	113.1
Right-of-way (3)	2.0	2.0	2.0	1.9	1.9	46.9	56.7
Product purchase obligations(4)	23.5	24.5	24.7	16.2	0.9	0.1	89.9
Service contract obligations(5)	26.8	21.8	13.2	2.3	—	—	64.1
Total	$ 619.8	$ 94.9	$ 652.6	$ 994.9	$ 212.2	$ 2,099.8	$ 4,674.2

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

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

(3) Right-of-way payments are estimated to be approximate $1.9 million to $2.0 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 2014.

(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.

The payments made under our obligations and commitments for the years ended December 31, 2009, 2008 and 2007 were $895.8 million, $947.1 million and $822.5 million, respectively.

Cash Requirements for Future Growth

Capital Spending

We expect to make additional expenditures during the next year for the construction of additional natural gas and crude oil transportation infrastructure primarily for the Alberta Clipper Project. In 2010, we expect to spend approximately $800 million on the Alberta Clipper Project and on other expansion 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. At December 31, 2009, we had approximately $248.7 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2010.

We expect to analyze potential acquisitions with a focus on natural gas pipelines, refined products pipelines, terminals, and related facilities. We will seek opportunities for accretive acquisitions throughout the United States, particularly in the U.S. Gulf Coast area, where asset acquisitions are anticipated in and around our existing natural gas business. We expect that the funds needed to achieve such acquisitions will be obtained through a combination of cash flows from operating activities, borrowings under our credit facilities and the issuance of additional debt and equity securities.

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 includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. We also began including a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as core maintenance expenditures beginning in 2009, which totaled $15.1 million for the year ended December 31, 2009. Enhancement expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and core maintenance for the year ending December 31, 2010. Although we anticipate making the expenditures in 2010, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. 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 $1.3 billion, including $68.9 million on core maintenance activities, for the year ended December 31, 2009. For the full year ending December 31, 2010, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in billions)
System enhancements	$ 0.3
Core maintenance activities	0.1
Alberta Clipper	0.4
	$ 0.8

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 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 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 components of our programs have increased over time as our pipeline systems age. We anticipate beginning a comprehensive program in 2010 to upgrade sections of our liquids petroleum pipeline system located in eastern Michigan that were installed in the late 1960's. This program will likely extend over several years and will require additional capital expenditures.

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through December 31, 2009, the incremental capacity that will or has become available upon completion of the project and the periods we expect to complete, or completed the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures			
	Estimated Total Cost	Actual Expenditures through December 31, 2009	Estimated Incremental Capacity Oil	Expected Completion
	(in billions)		(Kbpd)[1]	
Southern Access expansion (Lakehead)	$ 2.1	$ 2.1	400	Completed-April 2009
Alberta Clipper (Lakehead)	1.3	0.9	450	April 2010
North Dakota Phase VI expansion	0.2	0.1	50	Completed-January 2010
Total	$ 3.6	$ 3.1	900	

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to decline over the next year following completion of the Alberta Clipper project. Core maintenance capital, however, is anticipated to increase over that period of time due to the growth of our pipeline systems and the aging of portions of these systems.

We anticipate funding the system enhancement capital expenditures temporarily through borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

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.

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing. In the current environment we will consider acquisitions in geographic areas of current focus where assets are complementary to our existing systems. We will also consider acquisitions that step out from our current geographical areas and lines of business on a very selective basis. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

Derivative Activities

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

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, 2009 for each of the indicated calendar years:

	Notional	2010	2011	2012	2013	2014	Total
				(dollars, in millions)			
Swaps							
Natural gas[1]	133,332,304	$ (5.1)	$ (19.6)	$ (5.9)	$ 2.3	$ —	$ (28.3)
NGL[2]	5,703,255	(26.3)	2.3	6.2	(1.0)	—	(18.8)
Crude[2]	2,700,900	(7.5)	(10.0)	(5.3)	(1.3)	(0.4)	(24.5)
Options-calls							
Natural gas—calls written[1]	730,000	(0.6)	(0.8)	—	—	—	(1.4)
Options-puts							
Natural gas—puts purchased[1]	730,000	—	—	—	—	—	—
NGL—puts purchased[2]	1,271,647	3.2	2.4	3.2	—	—	8.8
Crude—puts purchased[2]	298,935	0.6	—	—	—	—	0.6
Forward contracts							
Crude[2]	644,594	0.2	—	—	—	—	0.2
NGL[2]	508,955	(3.7)	—	—	—	—	(3.7)
Totals		$ (39.2)	$ (25.7)	$ (1.8)	$ —	$ (0.4)	$ (67.1)

(1) Notional amounts for natural gas are recorded in millions of British thermal units ("MMBtu").

(2) Notional amounts for NGL and Crude are recorded in Barrels ("Bbl").

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at December 31, 2009 for each of the indicated calendar years:

	Notional Amount	2010	2011	2012	2013	2014	Thereafter	Total
				(dollars in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$ 975.0	$ (7.9)	$ (14.5)	$ (5.3)	$ (0.9)	$ —	$ —	$ (28.6)
Fixed to Floating	125.0	5.4	3.4	1.7	0.5	—	—	11.0
Pre-issuance hedges	1,120.0	(6.8)	—	24.9	14.1	—	—	32.2
Interest Rate Caps	400.0	0.5	—	—	—	—	—	0.5
		$ (8.8)	$ (11.1)	$ 21.3	$ 13.7	$ —	$ —	$ 15.1

Operating Activities

Net cash provided by our operating activities was $728.4 million in 2009 compared with $543.3 million in 2008. The change in operating cash flow is directly attributable to the operating performance of our Liquids and Natural Gas systems and marketing activities as discussed above in the section *Results of Operations—By Segment*. In addition, cash flows associated with changes in our working capital accounts for the year ended December 31, 2009 were higher than the same period of 2008 due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2009 was $1,173.6 million, a decrease of $254.7 million from the $1,428.3 million used during the same period of 2008. The decrease is primarily attributable to the $91.0 million reduction of amounts spent in 2009 on our construction projects as compared to the same period of 2008. The decrease in the amounts spent on our construction projects is primarily attributable to completion of the second stage of our Southern Access project. Also, during 2009 we sold non-core natural gas pipeline assets for proceeds of $150.8 million. We did not engage in a similar transaction in 2008.

Financing Activities

Net cash provided by financing activities during the year ended December 31, 2009 was $248.9 million, a decrease of $925.5 million from the $1,174.4 million generated during the year ended December 31, 2008. The reduction in the amount of cash provided by financing activities is due primarily to the approximately $2 billion decrease in debt and equity security issuances during 2009 as compared with 2008. Additionally, during 2009 we repaid $389.7 million of our senior notes that became due, and $130.0 million of affiliate notes, in addition to $108.3 million more in distributions to our partners as compared with the same period of 2008.

Partially offsetting the cash out flows from financing activities are $1,369.1 million of increases in short-term borrowings over the $501.2 million of repayments we made in the comparable period of 2008. We also received a $329.7 million contribution from our general partner and its affiliate during 2009 for its ownership interest in the Alberta Clipper Project that was not present for the same period in 2008. For the year ended December 31, 2009, we had gross borrowings of $5,522.1 million under our Credit Facility and gross repayments of $4,923.9 million, including $3,092.1 million of non-cash borrowings and repayments.

Cash 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 net reductions to reserves less all of our cash disbursements and net changes to reserves. We retain 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 a delegation of control agreement, computes the amount of our available cash.

As the owner of our i-units, Enbridge Management 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.

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 federal income tax characteristics, in all material respects, to the intrinsic economic and federal income tax characteristics of our outstanding Class A common units. Our general partner made this determination after adjustments were made to the capital accounts of our limited partners in connection with the private placement of Class A common units.

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, even though the i-unit holder will not receive cash. We retain the cash for use in our operations to finance a portion of our capital expansion projects. During 2009, we distributed a total of 1,625,812 i-units through quarterly distributions to Enbridge Management, compared with 1,198,969 in 2008. Additionally, in 2009 we distributed a total of 1,644,307 Class C units to the holders of our Class C units compared with 1,615,601 in 2008. We retained \$121.4 million, \$126.4 million, and \$107.5 million in 2009, 2008, and 2007, respectively, related to the i-unit and Class C unit distributions.

Our annual cash distribution rate is \$3.96 per unit, or \$0.99 per quarter for the years ended December 31, 2009 and 2008. We expect that all cash distributions will be paid out of operating cash flows over the long term. However, from time to time, we may temporarily borrow under our Credit Facility or use cash retained by issuance of payment in-kind distributions for the purpose of paying cash distributions. We may do this until we realize the full impact of assets being developed on operations or to respond to expected short-term aberrations in our performance caused by market disruption events or depressed commodity prices. We expect that our major capital expansion projects will be accretive to distributable cash flow when they are completed and operational. 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.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On January 29, 2010, the board of directors of Enbridge Management declared a distribution payable to our partners on February 12, 2010. The distribution was paid to unitholders of record as of February 5, 2010, of our available cash of \$131.7 million at December 31, 2009, or \$0.99 per limited partner unit. Of this distribution, \$115.2 million was paid in cash, \$16.2 million was distributed in i-units to our i-unitholder, and \$0.3 million was retained from the General Partner in respect of the i-unit distribution to maintain its two percent general partner interest.

Regulatory—North Dakota Tariff Filing

Effective January 1, 2010, we increased the rates for transportation on our North Dakota system to include a new surcharge related to the recent completion of our Phase VI Expansion program, which increased capacity on the pipeline from 110,000 Bpd to 161,000 Bpd. This surcharge is applicable for the seven years immediately following the January 1, 2010 in-service date of the Phase VI Expansion program. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook and the looping surcharge is applied to all volumes originating at Trenton and Alexander. The rates and surcharges for transportation of light crude oil to principle delivery points via trunk lines on the Enbridge North Dakota System are set forth below:

	Published Rate per Barrel FERC No. 61[1]	Phase VI Surcharge Per Barrel	Published Rate per Barrel FERC No. 64[2]
From Glenburn, Haas, Minot, Newberg, Sherwood, Stanley and Wiley, North Dakota to Clearbrook, Minnesota	$ 1.0495	$ 0.6078	$ 1.6573
From Brush Lake and Dwyer, Montana and Grenora, North Dakota to Clearbrook, Minnesota	1.1763	0.6078	1.7841
From Clear Lake, Dagmar, Flat Lake and Reserve, Montana to to Clearbrook, Minnesota	1.2043	0.6078	1.8121
From Tioga, North Dakota to Clearbrook, Minnesota	1.0774	0.6078	1.6852
From Trenton and Missouri Ridge, North Dakota to Clearbrook, Minnesota	2.0130	0.6078	2.6208
From Alexander, North Dakota to Clearbrook, Minnesota	2.0550	0.6078	2.6628
From Brush Lake, Dagmar and Clear Lake, Montana to Tioga, North Dakota	0.5496	—	0.5496
From Reserve, Montana to Tioga, North Dakota	0.6200	—	0.6200
From Trenton and Missouri Ridge, North Dakota to Tioga, North Dakota	1.2171	—	1.2171
From Alexander, North Dakota to Tioga, North Dakota	1.2589	—	1.2589

(1) Pursuant to FERC Tariff No. 61 as filed with the FERC on May 29, 2009, with an effective date of July 1, 2009.

(2) Pursuant to FERC Tariff No. 64 as filed with the FERC on November 30, 2009 with an effective date of January 1, 2010.

Lakehead Line 2b Leak

On January 8, 2010, an unexpected release on Line 2b of our Lakehead system occurred in Pembina County, North Dakota. We immediately shut down our pipelines in the vicinity and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline. We completed the excavation and repairs and returned the line to service within five days. Line 2b was restarted January 13, 2010, once repairs on the pipeline were completed. The volume of oil released was approximately 3,000 barrels, which was largely contained in an area surrounding the pipeline leak. We continue to work with federal and state environmental and pipeline safety regulators to investigate the cause of the leak. We have the potential of incurring additional costs in connection with this incident, including expenditures necessary to remediate any operating condition that is determined to have caused the incident. We do not expect the costs related to the containment, cleanup and repair of the pipeline to significantly impact our operating results, cash flows or financial position.

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.

Crude Oil Over/Short Balance and Crude Oil Measurement Gains/Losses

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 crude oil measurement gains/losses and our crude oil over/short balance based on mathematical calculations and physical measurements, 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 crude oil over/short balance or revision of our crude oil measurement gain/loss estimates. 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 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 U.S. 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 cost 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 and Intangibles

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 value 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. At the time we determine that an impairment has occurred, we will reduce the carrying value of goodwill to its fair value.

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. 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 certain 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 the intangibles are expected 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, the intangibles are written 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 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 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 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.

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 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 credit default swap spread rates, which are updated quarterly. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and are also adjusted quarterly based on current default swap spread rates on our outstanding indebtedness. 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 and commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). 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. In accordance with the authoritative accounting guidance, we record all derivative financial instruments on 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 depends on the intended use and designation of each instrument. For our derivative financial instruments related to commodities that do not qualify for hedge accounting, the change in market value is recorded as a component of "Cost of natural gas" in the consolidated statements of income. For our derivative financial instruments related to interest rates that do not qualify for hedge accounting, the change in fair market value is recorded as a component of "Interest expense" in the consolidated statements of income.

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 the cash flow and fair value hedges can affect net income for each period. We use published market price information where available, or quotations from over-the-counter ("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 objectives, and the methods 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 or the fair value 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. We determine the change in fair market value of financial instruments designated and qualifying as fair value hedges each period which we record in earnings. In addition, we calculate the change in the fair market value of the hedged item which is also recorded in earnings. To the extent that the two valuations offset, the hedge is effective and net earnings is not affected.

Our earnings are also affected by use of the mark-to-market method of accounting as required under 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 fair value of these instruments on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than deferring them until the firm commitment or anticipated transactions affect earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to 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 "Accounts payable and other" and "Other long-term liabilities" in our consolidated statements of financial position at their undiscounted amounts. 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, the minimum of the range of probable loss. We typically expense legal costs associated with loss contingencies as such costs are incurred.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Fair Value Measurements and Disclosures

In January 2010, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2010-06—*Fair Value Measurements and Disclosures*, referred to as ASU No. 2010-06. ASU No. 2010-06 updates the current authoritative guidance pertaining to fair value measurements by enhancing existing disclosure requirements for both the valuation techniques and inputs used to determine fair value measurements.

The new disclosure requirements created by this ASU are as follows:

- An entity should disclose the amounts of significant transfers in and out of Level 1 and 2 fair value measurements;
- Discussion of the reasons for transfers between all levels within the fair value hierarchy; and
- Provide a reconciliation, on a gross basis, for those fair value measurements that use significant unobservable inputs (Level 3) and present separate information about the purchases, sales, issuances, and settlements within the reconciliation.

The enhanced disclosure requirements provided by ASU No. 2010-06 include the following:

- Fair value measurements should be disclosed for each class of assets and liabilities;
- The inputs and valuation techniques used to measure the fair value for both recurring and nonrecurring fair value measurements that fall into either Level 2 or Level 3 of the fair value hierarchy.

The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, with the exception of the disclosures regarding the purchases, sales, issuances and settlements within the reconciliation of Level 3 fair value measurements which are effective for fiscal years and interim periods beginning after December 15, 2010. We did not adopt the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material effect on our financial statements other than modifications to our existing fair value disclosures.

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 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 credit facilities 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 U.S. dollars. 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, 2009 and 2008.

	December 31, 2009									December 31, 2008	
	Average Interest Rate	Expected Maturity of Carrying Amounts by Fiscal Year							Fair Value	Carrying Amount	Fair Value
		2010	2011	2012	2013	2014	Thereafter	Total			
		(dollars in millions)									
Liabilities											
Fixed Rate:											
First Mortgage Notes	9.150%	$ 31.0	$ 31.0	$ —	$ —	$ —	$ —	$ 62.0	$ 69.9	$ 93.0	$ 93.8
Senior Notes due 2009	4.000%	—	—	—	—	—	—	—	—	175.0	175.2
Senior unsecured zero coupon notes due 2022	5.358%	—	—	—	—	—	—	—	—	214.7	211.0
Senior Notes due 2012	7.900%	—	—	100.0	—	—	—	100.0	109.5	99.9	93.7
Senior Notes due 2013	4.750%	—	—	—	199.9	—	—	199.9	201.2	199.9	163.4
Senior Notes due 2014	5.350%	—	—	—	—	199.9	—	199.9	206.9	199.9	151.3
Senior Notes due 2016	5.875%	—	—	—	—	—	299.8	299.8	315.0	299.8	234.5
Senior Notes due 2018	7.000%	—	—	—	—	—	99.9	99.9	111.6	99.9	81.9
Senior Notes due 2018	6.500%	—	—	—	—	—	398.2	398.2	433.2	398.0	317.7
Senior Notes due 2019	9.875%	—	—	499.8	—	—	—	499.8	664.8	499.7	500.4
Senior Notes due 2028	7.125%	—	—	—	—	—	99.9	99.9	110.9	99.8	72.7
Senior Notes due 2033	5.950%	—	—	—	—	—	199.7	199.7	188.8	199.7	119.7
Senior Notes due 2034	6.300%	—	—	—	—	—	99.8	99.8	98.0	99.8	62.3
Senior Notes due 2038	7.500%	—	—	—	—	—	398.9	398.9	449.5	398.9	289.2
Junior subordinated notes due 2067	8.050%	—	—	—	—	—	399.4	399.4	381.8	399.3	209.3
Variable Rate:											
Credit Facility	0.540%	—	—	—	765.0	—	—	765.0	765.0	166.8	166.8

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our variable rate debt obligations are issued. To mitigate the volatility of our cash flows that can arise due to fluctuations in interest rates on our variable rate debt, we use derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to manage the risks associated with the fluctuations in interest rates. 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.

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 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, 2009.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[(1)]	Fair Value at December 31, 2009	Fair Value at December 31, 2008
		(dollars in millions)		(dollars in millions)	
Contracts maturing in 2010					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 250	1.68%	$ (2.5)	$ —
Interest Rate Caps	Non-qualifying	200	1.09%	0.2	—
Contracts maturing in 2011					
Interest Rate Caps	Non-qualifying	$ 200	1.14%	$ 0.3	$ —
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 600	4.15%	$ (16.9)	$ —
Interest Rate Swaps—Pay Fixed	Non-qualifying	125	4.35%	(9.2)	(13.5)
Interest Rate Swaps—Receive Fixed	Non-qualifying	125	4.75%	11.0	15.3
Contracts settling prior to maturity					
2010—Pre-issuance Hedges	Cash Flow Hedge	$ 220	4.62%	$ (6.8)	$ —
2012—Pre-issuance Hedges	Cash Flow Hedge	600	4.57%	24.9	—
2013—Pre-issuance Hedges	Cash Flow Hedge	300	4.62%	14.1	—

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

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at December 31, 2009 for each of the indicated calendar years:

	Notional Amount	2010	2011	2012	2013	2014	Thereafter	Total
		(dollars in millions)						
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$ 975.0	$ (7.9)	$ (14.5)	$ (5.3)	$ (0.9)	$ —	$ —	$ (28.6)
Fixed to Floating	125.0	5.4	3.4	1.7	0.5	—	—	11.0
Pre-issuance hedges	1,120.0	(6.8)	—	24.9	14.1	—	—	32.2
Interest Rate Caps	400.0	0.5	—	—	—	—	—	0.5
		$ (8.8)	$ (11.1)	$ 21.3	$ 13.7	$ —	$ —	$ 15.1

COMMODITY PRICE RISK

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

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at December 31, 2009 and 2008.

	At December 31, 2009						At December 31, 2008	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	5,875,411	$ 5.63	$ 5.88	$ 1.6	$ (3.1)	$ 2.5	$ (6.5)
	NGL	120,000	73.80	45.30	3.4	—	—	(1.3)
Receive fixed/pay variable	Natural Gas	10,809,500	4.52	5.74	2.9	(16.0)	2.2	(27.5)
	NGL	3,312,010	40.39	49.36	9.7	(39.4)	28.0	—
	Crude Oil	720,790	71.95	82.30	3.1	(10.6)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	86,551,709	5.62	5.51	13.0	(3.5)	0.8	(3.1)
Physical Contracts								
Receive fixed/pay variable	NGL	443,955	52.44	61.02	—	(4.0)	—	—
	Crude Oil	250,666	73.50	79.83	—	(1.6)	—	—
Receive variable/pay fixed	NGL	65,000	74.41	70.66	0.3	—	—	—
	Crude Oil	248,666	79.58	72.37	1.8	—	—	—
Receive variable/pay variable	Crude Oil	145,262	76.88	76.93	0.1	(0.1)	—	—
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	878,475	$ 6.21	$ 9.78	$ —	$ (3.1)	$ 2.6	$ (3.4)
	NGL	120,000	74.90	47.67	3.2	—	—	—
Receive fixed/pay variable	Natural Gas	8,426,000	3.98	6.31	—	(19.3)	1.1	(28.1)
	NGL	1,232,240	58.32	59.08	6.1	(7.0)	13.0	(0.3)
	Crude Oil	769,700	72.91	86.11	—	(10.0)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.40	6.22	2.9	(0.1)	—	(1.0)
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	759,709	$ 6.41	$ 9.96	$ —	$ (2.6)	$ 0.8	$ (2.1)
	NGL	—	—	—	—	—	—	(0.9)
Receive fixed/pay variable	Natural Gas	2,327,500	4.90	6.63	0.3	(4.2)	—	(5.8)
	NGL	777,750	69.48	61.23	7.1	(0.9)	15.7	—
	Crude Oil	559,980	77.92	88.00	—	(5.3)	0.8	—
Receive variable/pay variable	Natural Gas	1,089,000	6.43	5.87	0.6	—	—	—
Portion of contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 6.43	$ 2.3	$ —	$ 2.0	$ —
	NGL	141,255	47.45	55.17	—	(1.0)	—	—
	Crude Oil	467,930	86.40	89.49	2.3	(3.6)	3.4	—
Portion of contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	182,500	$ 88.72	$ 91.30	$ —	$ (0.4)	$ —	$ —

(1) Volumes of Natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and Crude Oil are measured in barrels, or Bbl.

(2) Weighted average prices received and paid 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, 2009 and 2008, 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.

The following table provides summarized information about the fair values of expected cash flows for our outstanding commodity based option contracts at December 31, 2009 and 2008.

	At December 31, 2009						At December 31, 2008	
					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 2010								
Calls (written)	Natural Gas[4]	365,000	$ 4.31	$ 5.79	$ —	$ (0.6)	$ —	$ (1.0)
Puts (purchased)	Natural Gas[4]	365,000	3.40	5.79	—	—	—	—
	NGL	971,995	44.30	53.69	3.2	—	5.2	—
	Crude Oil	298,935	70.87	82.30	0.6	—	—	—
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas[4]	365,000	$ 4.31	$ 6.33	$ —	$ (0.8)	$ —	$ (1.0)
Puts (purchased)	Natural Gas[4]	365,000	3.40	6.33	—	—	—	—
	NGL	170,820	51.89	46.73	2.4	—	2.7	—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	128,832	$ 66.80	$ 50.34	$ 3.2	$ —	$ 4.4	$ —

(1) Volumes of Natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and Crude Oil are measured in barrels, or 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, 2009 and 2008, 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.

(4) Transactions which, in combination, create a collar, representing a floor and ceiling on the price, which provides long-term price protection.

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, which we 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 use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

In accordance with the 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 "Cost of natural gas" 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. 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.

If a derivative financial instrument is designated and qualifies as a hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings and is adjusted by the gain or loss resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge's change in fair market value is recorded in earnings as the amount that is not offset by the gain or loss on the change in fair market value of the underlying asset or liability. Although we do not presently hold any derivative financial instruments designated as fair value hedges, in the past we have designated derivatives as fair value hedges of fixed rate debt in periods of high interest rates to achieve effectively lower variable rates. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in "Interest expense" on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, to qualify as a fair value hedge 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-qualified." These non-qualified 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" 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 gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

- *Natural Gas Collars*—In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options and, pursuant to the authoritative accounting guidance, do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

- *Optional Natural Gas Processing Volumes*—In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural gas contracts allow us the option of processing natural gas when it is economical and ceasing to do 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 purchases of natural gas required for processing. We will typically designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

- *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. Prior to April 1, 2009, forward contracts were not treated as derivative financial instruments pursuant to the normal purchase normal sale, or NPNS, exception allowed under authoritative accounting guidance, since the forward contracts resulted in physical receipt or delivery of NGLs. However, evolving markets for NGLs have increased opportunities for a portion of our forward contracts to be settled net rather than physically receiving or delivering the NGLs. Accordingly, we have revoked the NPNS exception on certain forward contracts associated with the liquids marketing operations of Dufour Petroleum, L.P., our wholly-owned subsidiary, executed after April 1, 2009. 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 will be subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.

Interest Rate Risk Exposures:

- *Interest Rate Caps*—At the corporate level, our earnings and cash flows are affected by fluctuations in interest rates associated with our variable interest rate debt. Our variable interest rate borrowing cost is determined at the time of each borrowing or interest rate reset based upon a posted LIBOR for the period of borrowing or interest rate reset, increased by a defined credit spread. In order to mitigate the negative effect that increasing interest rates can have on our cash flows, we have entered into interest rate caps, which establish a ceiling averaging approximately 1.12% on the interest rates we pay on up to $400 million of our variable rate indebtedness. Although our interest rate caps protect us from the adverse effect of higher interest rates, they do not qualify for hedge accounting and, as a result, changes in the market value of these instruments will create additional volatility in our earnings.

In all instances related to the commodity price exposures described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we employ for the derivative financial instruments we use 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 historical cost) 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.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of "Cost of natural gas" and "Interest expense" in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ (0.7)	$ (0.1)	$ —
Non-qualified hedges	(35.7)	85.1	(59.0)
Marketing			
Non-qualified hedges	20.7	(16.2)	(3.8)
Commodity derivative fair value gains (losses)	(15.7)	68.8	(62.8)
Corporate			
Non-qualified interest rate hedges	0.5	—	(1.4)
Derivative fair value gains (losses)	$ (15.2)	$ 68.8	$ (64.2)

Derivative Positions

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

	December 31,	
	2009	2008
	(in millions)	
Other current assets	$ 14.8	$ 70.6
Other assets, net	43.7	75.7
Accounts payable and other	(59.2)	(40.6)
Other long-term liabilities	(50.5)	(71.0)
	$ (51.2)	$ 34.7

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 that were in gain positions 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 and NGL sales and purchase agreements.

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 $1.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the years ended December 31, 2009, 2008 and 2007, we reclassified from AOCI to "Cost of natural gas" on our consolidated statements of income net gains of $39.9 million and net losses of $140.5 million and $94.8 million, respectively. Additionally, for the year ended December 31, 2009, we reclassified from AOCI to "Interest expense" on our consolidated statement of income net losses of $2.3 million. We estimate that approximately $31.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2009, will be reclassified from AOCI to earnings during the next twelve months.

As of December 31, 2009, we have provided letters of credit totaling $13.1 million in lieu of providing cash collateral to our counterparties pursuant to the terms of our International Securities Dealers Association ("ISDA®") agreements.

Counterparty Credit Risk

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

	December 31, 2009	December 31, 2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	14.2	(39.6)
A	(63.1)	73.3
Lower than A	(3.2)	(1.2)
	(52.1)	32.5
Credit valuation adjustment	0.9	2.2
Total	$ (51.2)	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

As the net receivable of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also declined. When credit thresholds are met pursuant to the terms of our ISDA® financial contracts, we have the right to require collateral from our counterparties. We have included any cash collateral received in the balances listed above. 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 or require immediate settlement of 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 each counterparty's credit rating. 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, but the agreements do not contain additional triggers or automatic termination clauses relating to credit downgrades. 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 the tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At December 31, 2009, we were in an overall net liability position of $51.2 million, which included assets of $58.5 million. Based on our forward positions at December 31, 2009, if our credit ratings were downgraded to BBB- by S&P or Baa3 by Moody's, we would be required to provide $39.0 million in the form of either cash collateral or letters of credit to satisfy the requirements of our ISDA® agreements.

Counterparties to our derivative financial instruments include credit concentrations with U.S. financial institutions, international financial institutions, investment banking entities and, to a lesser extent, international integrated oil companies. At December 31, 2009, approximately $18.8 million of our liabilities for derivative financial instruments were due from us to U.S. financial institutions, including investment banks. We are in net liability positions of $30.2 million and $3.4 million with non-U.S. financial institutions and small non-integrated energy companies, respectively, representing amounts payable by us. We also have approximately $1.2 million of receivables that are payable to us from integrated oil companies. We are holding no cash collateral on our asset exposures and we have provided letters of credit totaling $13.1 million relating to our liability exposure pursuant to the margin thresholds in effect at December 31, 2009 under our ISDA® agreements.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the notes thereto and the independent registered public accounting firm's report thereon, and unaudited supplementary information, appear beginning on page F-2 of this report, and are incorporated into this report by reference. Reference should be made to the "Index to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this report.

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 our annual and quarterly reports under the Securities Exchange Act of 1934, as amended. Our management has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2009. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. 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 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership's financial statements for external reporting purposes in accordance with U.S. 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 U.S. 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.

The Partnership's internal control over financial reporting may not prevent or detect all misstatements because of its inherent limitations. Additionally, 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 deterioration in the degree of compliance with our policies and procedures.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2009, 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, 2009.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has issued an attestation report on our internal control over financial reporting as of December 31, 2009, beginning on page F-2.

Changes in Internal Control Over Financial Reporting

We have not made any changes 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, 2009.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

We are a limited partnership and have no officers or directors of our own. Set forth below is certain information concerning the directors and executive officers of our general partner and of Enbridge Management as the delegate of our general partner under a Delegation of Control Agreement among us, our general partner and Enbridge Management. All directors of our general partner are elected annually and may be removed by Enbridge Pipelines, as the sole stockholder of our general partner. All directors of Enbridge Management were elected and may be removed by our general partner, as the sole holder of Enbridge Management's voting shares. All officers of our general partner and Enbridge Management serve at the discretion of the respective boards of directors of our general partner and Enbridge Management. All directors and officers of our general partner hold identical positions in Enbridge Management.

Name	Age	Position
Directors and Executive Officers:		
Martha O. Hesse	67	Director and Chairman of the Board
Jeffrey A. Connelly	63	Director
George K. Petty	68	Director
Dan A. Westbrook	57	Director
Stephen J.J. Letwin	54	Managing Director and Director
Terrance L. McGill	55	President and Director
Stephen J. Wuori	52	Executive Vice President—Liquids Pipelines and Director
Officers:		
Richard L. Adams	45	Vice President—U.S. Operations, Liquids Pipelines
E. Chris Kaitson	53	Vice President—Law and Assistant Secretary
John A. Loiacono	47	Vice President—Commercial Activities
Mark A. Maki	45	Vice President—Finance
Al Monaco	50	Executive Vice President—Major Projects
Stephen J. Neyland	42	Controller
Kerry C. Puckett	48	Vice President—Engineering and Operations, Gathering and Processing
Jonathan N. Rose	42	Treasurer
Allan M. Schneider	51	Vice President—Regulated Engineering and Operations
Bruce A. Stevenson	54	Corporate Secretary
Leon A. Zupan	54	Vice President—Liquids Pipelines Operations

Martha O. Hesse was elected as Chairman of the Board in May 2007 and as a director of the General Partner and Enbridge Management in March 2003 and serves as a member of the Audit, Finance & Risk Committee. 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 AMEC plc, Mutual Trust Financial Group, and Terra Industries, Inc.

Jeffrey A. Connelly was elected a director of the General Partner and Enbridge Management in January 2003 and serves as the Chairman of the Audit, Finance & Risk Committee. Mr. Connelly served as Executive Vice President, Senior Vice President and Vice President of the Coastal Corporation from 1988 to 2001.

George K. Petty was elected a director of the General Partner in February 2001 and Enbridge Management upon its formation and serves on the Audit, Finance & Risk Committee. Mr. Petty has served as a director of

Enbridge since January 2001. Mr. Petty served as President and Chief Executive Officer of Telus Corporation, a Canadian telecommunications company, from November 1994 to November 1999. Mr. Petty retired in 1994 from AT&T Corporation as a Vice-President after 25 years of service. He currently serves on the Board of Directors of Fuelcell Energy Corporation.

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. In 2008 he joined the Board of Directors of the Carrie Tingley Hospital Foundation. From May 2007 until August 2008 he has served on the Board of Directors of Synenco Energy Inc. where he was a member of the their Audit & Risk and Finance Committees, until being acquired by Total E&P Canada. From January 2006 until May 2008, he served on the Board of Directors of Knowledge Systems Inc., a privately held U.S. company prior to its acquisition by Halliburton. From 2001 to 2005 Mr. Westbrook served as President of BP China Gas, Power & Upstream and Vice-Chairman of the Board of Directors of Dapeng LNG, a Sino joint venture between BP subsidiaries and other Chinese companies. From 1999 to 2001 Mr. Westbrook was the Associate President with BP in Argentina. Prior to that he held executive positions with BP in Houston, Russia, Chicago, and The Netherlands.

Stephen J.J. Letwin was elected Managing Director of the General Partner and Enbridge Management in May 2006, and is also Executive Vice President, Gas Transportation & International of Enbridge. Prior to his election he served Enbridge as Group Vice President, Gas Strategy & Corporate Development from April 2003; prior thereto he served Enbridge as Group Vice President, Distribution & Services from September 2000. He currently serves as a director of Precision Drilling Trust and Gaz Metro, LP.

Terrance L. McGill was elected President of the General Partner and Enbridge Management in 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.

Stephen J. Wuori was elected a director of the General Partner and Enbridge Management in January 2008 and is also the Executive Vice President of Liquids Pipelines for the General Partner and Enbridge Management. Mr. Wuori holds similar responsibilities with Enbridge. He was previously 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.

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.

E. Chris Kaitson was elected Vice President, Law and Deputy General Counsel 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 acquired by Enbridge in May 2001.

John A. Loiacono was elected 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 in February 2000 as an Asset Optimizer.

Mark A. Maki was elected Vice President, Finance of the General Partner and Enbridge Management in July 2002. Prior to that time, he 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.

Al Monaco was elected Executive Vice President, Major Projects of the General Partner and Enbridge Management in January 2008 and holds similar responsibilities with Enbridge. Prior to that Mr. Monaco was President of Enbridge Gas Distribution Inc. 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 in April 2003.

Stephen J. Neyland was elected Controller of the General Partner and Enbridge Management effective September 2006. Prior to his election 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 elected Vice President, Engineering and Operations, Gathering and Processing of the General Partner and Enbridge Management in October 2007. Prior to his election 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.

Jonathan N. Rose was elected as Treasurer of the General Partner and Enbridge Management in January 2008. He was previously Assistant Treasurer of the General Partner and Enbridge Management from July 2005. Mr. Rose is also a Director, Finance of Enbridge, a position he has held from October 2007, prior to which he was Manager, Finance from 2004. Prior to that Mr. Rose was a Vice President with Citigroup Global Corporate and Investment Bank from 2001 to 2004.

Allan M. Schneider was elected Vice President, Regulated Engineering and Operations of the General Partner and Enbridge Management in October 2007. Prior to his election 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 from December 2000.

Bruce A. Stevenson was elected 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.

Leon A. Zupan was elected Vice President, Liquids Pipelines Operations of the General Partner and Enbridge Management in July 2004, and holds similar responsibilities with Enbridge. Mr. Zupan previously served as Vice President, Development & Services for Enbridge Pipelines from 2000.

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 for the year ended December 31, 2009, we believe that all filings required to be made under Section 16(a) during 2009 and prior years were timely made or disclosed as required.

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 our general partner. Because we are a controlled company, the NYSE listing standards do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of our general partner's board of directors.

The NYSE listing standards require our Chief Executive Officer to annually certify that he is not aware of any violation by us of the NYSE corporate governance listing standards. Accordingly, this certification was provided as required to the NYSE on March 10, 2009.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

We have adopted a Code of Ethics applicable to the senior financial 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 the Code of Ethics for Senior Financial Officers. 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, TX 77002.

We also have a Statement of Business Conduct applicable to all of the employees, officers and directors of Enbridge Management. 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. 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, TX 77002.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how the Board of Enbridge Management should function and the Board's 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. 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, TX 77002.

AUDIT, FINANCE & RISK COMMITTEE

Enbridge Management has an Audit, Finance & Risk Committee (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 is relying upon any exemptions from the foregoing independence requirements. The members of the Audit Committee are Jeffrey A. Connelly, Dan A. Westbrook, Martha O. Hesse and George K. Petty. 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 of Enbridge Management.

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, TX 77002.

Enbridge Management's board of directors has determined that Jeffrey A. Connelly and Martha O. Hesse 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, Finance and Risk Committee is independent as defined by Section 303A of the listing standards of the NYSE.

Ms. Hesse serves on the Audit Committees of the General Partner, AMEC plc., Mutual Trust Financial Group and of Terra Industries, Inc. In compliance with the provisions of the Audit, Finance & Risk Committee Charter, the boards of directors of the General Partner and of Enbridge Management have determined that Ms. Hesse's simultaneous service on such audit committees does not impair her ability to effectively serve on the Audit, Finance & Risk 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 in care of Chairman, Audit Committee, c/o Enbridge Energy Management, L.L.C., 1100 Louisiana Street, Suite 3300, Houston, TX 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of Enbridge Management meet at regularly scheduled executive sessions without management. Martha O. Hesse serves as the presiding director at those executive sessions. Persons wishing to communicate with the Company's independent directors may do so by writing in care of Chairman, Board of Directors, Enbridge Energy Partners, L.P., 1100 Louisiana Street, Suite 3300, Houston, TX 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, as 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 and operational 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, 2009 were:

- Stephen J. J. Letwin, Managing Director
- Terrance L. McGill, President
- Stephen J. Wuori, Executive Vice President—Liquids Pipelines
- Mark A. Maki, Vice President—Finance
- Al Monaco, Executive Vice President—Major Projects

Messrs. Letwin, Wuori and Monaco are also named executive officers of Enbridge, where Mr. Letwin also serves as Executive Vice President, Gas Strategy and International. As such, the Human Resources and Compensation Committee of the board of directors of Enbridge, or the HRC Committee, approves the elements of compensation of these individuals based on the recommendation of the chief executive officer of Enbridge, considering their positions within Enbridge on an enterprise-wide basis. Each of these executive officers completes a self-assessment. The chief executive officer of Enbridge documents the performance of each Enbridge executive officer during the year, reviews the compensation data provided by an outside consultant to the HRC Committee and makes a recommendation to the HRC Committee on the elements of compensation for those individuals. The HRC Committee reviews and approves the performance and compensation recommendations of the chief executive officer of Enbridge with respect to these executive officers.

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 chief executive officer of Enbridge and the HRC Committee do not review the elements of compensation for Messrs. McGill and Maki on an individual basis. The managing director of our general partner and Enbridge Management makes compensation recommendations for Messrs. McGill and Maki, which are subject to the Enbridge enterprise-wide review process described above. Enbridge's 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, their compensation is determined on the basis of their overall performance with respect to Enbridge and all of its affiliates and not solely based on their performance with respect to us.

We are a partnership and not a corporation for U.S. 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 and longer-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 percentage contributions to the operating results of Enbridge for the preceding five years:

2009	2008	2007	2006	2005
6%	5%	8%	7%	5%

The elements of total compensation for senior management of Enbridge, which include Messrs. Letwin, Wuori and Monaco, are:

- Base Salary—to provide a fixed level of compensation for performing day-to-day responsibilities, competency and for 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.
- Longer-term incentives—to recognize longer-term 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.
- Benefits—to provide security pertaining to health and welfare risks in a flexible manner to meet individual needs.

- Savings plan—to promote ownership of Enbridge shares and to provide the opportunity to save additional funds for retirement or other financial goals.
- Pension plan—to provide a competitive retirement benefit.
- Perquisites—to provide a competitive allowance to offset expenses largely related to the executive's role.
- Employment agreements—to provide specific total compensation terms in situations of involuntary termination or change of control.

The elements of compensation for Messrs. McGill and Maki are similar to those described above, except that neither has 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 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 STI Plan, 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 pay. 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 significant factor in determining incentive awards.

The following is a summary for 2009 of the incentive targets, payout range, and relative weighting between the Enbridge corporate, business unit and individual performance:

			Relative Weighting		
NEO	Target STI%[1]	Pay Out Range	Corporate	Business Unit	Individual
Stephen Letwin Managing Director	50%	0 - 100%	70%	15%	15%
Terry McGill President	40%	0 - 80%	50%	25%	25%
Stephen Wuori Executive Vice President, Liquids Pipelines	50%	0 - 100%	70%	15%	15%
Mark A. Maki Vice President, Finance	35%	0 - 70%	40%	30%	30%
Al Monaco Executive Vice President, Major Projects[2]	50%	0 - 100%	40%	50%	10%

1 All values are expressed as percentages of base pay.

2 The weightings for the EVP Major Projects were revised to ensure a strong focus on major project execution.

The overall performance multiplier and STI award are calculated as follows:

	Performance multiplier		STI Award
	Corporate target incentive opportunity x (0-2)		Base Salary $
+	Business unit target incentive opportunity x (0-2)	x	Target STI %
+	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 return on equity. This metric reflects the overall success in bringing new investments into service and managing existing investments to generate earnings in the best interests of Enbridge and its shareholders. The return on equity metric is applicable to each of the NEOs and represents a significant component of their individual STI awards.

The annual return on equity target, which is approved by the board of directors of Enbridge, is established with reference to longer-term objectives to achieve earnings growth and total returns. Actual return on equity performance is based on adjusted earnings to ensure the results are a fair reflection of performance. Adjustments for 2009 include:

- unrealized mark-to-market gains and losses from derivative activities; and
- non-recurring gains and losses resulting from dispositions of assets.

The 2009 return on equity target for Enbridge was 12.5%, representing the performance target from the Enbridge annual budget. Actual performance for Enbridge was 14.3% based on adjusted earnings. Based on this performance, the corporate performance multiplier for Enbridge was 2.0 out of 2.0. In addition to the calculated result, the board of directors of Enbridge considered the performance of Enbridge in 2009 relative to other key performance indicators, compared with the comparator peer group that is listed below in the section labeled *PSU Plan* and with companies in the TSX60 and TSX Composite indexes. The Enbridge board of directors considered performance over one, three, five and ten-year time periods for the following market-based metrics:

- dividend/share growth
- total shareholder return
- reward to risk

For almost all metrics, in all time periods assessed, Enbridge performed above the 75th percentile when compared to its comparator peer group. Enbridge also outperformed the TSX60 and TSX composite indexes for a majority of these metrics, over the time periods noted.

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 detail business unit performance measures for each of the NEOs, other than Mr. Letwin, are set forth in the tables which follow. Mr. Letwin's Gas Strategy and International business unit performance measure was an earnings target, which was exceeded, resulting in a business unit multiplier of 1.4 out of 2.0. The business unit multipliers included in the following tables reflect rounding and range from 0 to 2, with 1.0 meaning that the performance measure was met. The business units for each of the NEOs are set forth below their names in the following tables. The business units include the Partnership, but also include portions of other Enbridge businesses.

Terrance L. McGill Gas Transportation				
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Performance Multiplier**
Financial	50%	Gas Transportation Net Income	25%	1.5
		General & Administrative costs	12.5%	
		Operations & Maintenance costs	12.5%	
Environmental, Health & Safety	25%	Total Recordable Injury Frequency	5%	0.6
		Days Away Severity Rate	5%	
		Preventable Motor Vehicle Accidents	5%	
		Reportable Spills/Leaks	5%	
		Environmental Regulatory Citations	5%	
Employee Engagement & Compliance	25%	Survey Participation	5%	1.9
		Voluntary Turnover	5%	
		Compliance Training Participation	10%	
		SOx Compliance	5%	
		Business Unit Performance multiplier		**1.38**

Stephen J. Wuori Liquids Pipelines				
Performance Measure	**Weight**	**Sub Measure % Weightings**		**Performance Multiplier**
Financial	35%	ENB Liquids Pipelines Earnings	25%	1.4
		EEP Liquids Pipelines Earnings	9%	
		EPSI Liquids Pipelines Earnings	1%	
Environmental Health & Safety	17.5%	Days Away Injuries	3.5%	1.8
		Medical Aid Injuries	3.5%	
		Motor Vehicle Incidents	3.5%	
		Safety Observations	3.5%	
		EH&S Participation	3.5%	
System Integrity	17.5%	Mainline Releases	13.1%	1.8
		Off-Property Releases	2.2%	
		Completion of Leak Reduction Team Initiatives	2.2%	
Customer Satisfaction	15%	Positive working relationship with Enbridge	10%	0.8
		Enbridge responsiveness	5%	
Employee Retention & Performance Management	15%	Attraction	7.5%	2.0
		Retention	7.5%	
		Business Unit Performance multiplier		**1.54**

Mark A. Maki Gas Transportation				
Performance Measure	**Weight**	**Sub Measures & Weightings**		**Performance Multiplier**
Financial	50%	Gas Transportation Net Income	25%	1.5
		Liquids Pipelines Net Income (75% Canadian and 25% U.S.)	25%	
Environmental Health & Safety	25%	Total Recordable Injury Frequency	5%	0.6
		Days Away Severity Rate	5%	
		Preventable Motor Vehicle Accidents	5%	
		Reportable Spills/Leaks	5%	
		Environmental Regulatory Citations	5%	
Employee Engagement & Compliance	25%	Survey Participation	5%	1.9
		Voluntary Turnover	5%	
		Compliance Training Participation	10%	
		SOx Compliance	5%	
		Business Unit Performance multiplier		**1.38**

Al Monaco Major Projects			
Performance Measure	**Weight**	**Sub Measures & Weightings**	**Performance Multiplier**
Project Performance	36%	Cost	1.6
	33%	Schedule	1.4
	13%	Environmental/Regulatory	1.8
	12%	Safety	1.7
	6%	Quality	1.9
		Business Unit Performance multiplier	**1.57**

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 his respective portfolio, development of succession candidates, employee engagement, community involvement and leadership. The level of attainment of individual performance goals is determined by the chief executive officer of Enbridge for Messrs. Letwin, Wuori and Monaco and by Mr. Letwin for Messrs. McGill and Maki.

Summary of 2009 STI Plan 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)
Stephen J.J. Letwin	(70% x 2.00) = 1.40	(15% x 1.40) = 0.21	(15% x 1.90) = 0.29	1.90
Terrance L. McGill	(50% x 2.00) = 1.00	(25% x 1.38) = 0.35	(25% x 1.65) = 0.41	1.76
Stephen J. Wuori	(70% x 2.00) = 1.40	(15% x 1.54) = 0.23	(15% x 1.80) = 0.27	1.90
Mark A. Maki	(40% x 2.00) = 0.80	(30% x 1.38) = 0.41	(30% x 1.65) = 0.50	1.71
Al Monaco	(40% x 2.00) = 0.80	(50% x 1.57) = 0.79	(10% x 1.95) = 0.20	1.78

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 STI Award[2] (a x b x c)	Actual STI Award
Stephen J.J. Letwin	$520,000	50%	1.90	$492,700	$530,000
Terrance L. McGill	335,200	40%	1.76	235,646	250,650
Stephen J. Wuori[1]	496,497	50%	1.90	471,918	472,855
Mark A. Maki	265,300	35%	1.71	158,689	188,690
Al Monaco[1]	394,046	50%	1.78	350,701	437,828

(1) The dollar amounts presented for Mr. Wuori and Mr. Monaco have been converted from Canadian dollars, or CAD, to U.S. dollars, or USD, using the average exchange rate for 2009 of $1.142 CAD = $1 USD.

(2) The calculated STI award may differ from the amounts presented due to rounding.

The calculated STI award may be adjusted for Messrs. Letwin, Wuori and Monaco by a recommendation of the chief executive officer of Enbridge to the HRC Committee, which must approve any such recommendation. The managing director of our general partner and Enbridge Management may recommend adjustments to the calculated STI award for Messrs. McGill and Maki, which recommendations are reviewed by Enbridge's executive leadership team for fairness and consistency with enterprise-wide compensation.

The actual STI awards have been adjusted based on the recommendations of the chief executive officer of Enbridge for Messrs. Letwin and Monaco and the recommendations of Mr. Letwin with respect to Mr. McGill and Maki, based upon personal performance and contributions beyond the individual goals and objectives. Specifically:

- Mr. Letwin led the sale of Enbridge's ownership interest in the OCENSA pipeline in 2009, which was well timed and executed. Additionally, a new customer information system for the Gas Distribution business was also successfully implemented.
- Mr. Monaco successfully managed the ongoing execution of the Enbridge capital program resulting in the on-time and on-budget completion of several projects. The complexities involved in a program of this magnitude, the challenging economic climate and multiple jurisdictions warranted additional recognition.
- Mr. McGill and Mr. Maki demonstrated outstanding leadership in the areas of cost control and revenue maximization. As well, both leaders played a strong role in the sale of non-core assets at very attractive terms, which allowed us to avoid a dilutive external equity issuance. Lastly, Mr. Maki played a significant role in completing the financing transaction for the Alberta Clipper Project.

Longer-Term Incentives

Enbridge has three plans that make up its longer-term incentive program for senior management:

- A performance stock unit plan, or PSU Plan, which includes three-year phantom shares with performance conditions that impact payout;
- A performance-based stock option plan, or PBSO Plan, that includes eight-year options with performance and time vesting conditions; and
- An incentive stock option plan, or ISO Plan, which includes 10-year stock options with time vesting conditions.

Only the NEOs of Enbridge, including Messrs. Letwin, Wuori and Monaco, are eligible to receive grants under the PBSO Plan.

Enbridge believes that the combination of these longer-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 PBSO Plan and performance measures under the PSU Plan. Specifically, when earnings targets are achieved, the share price increases over the longer term and when Enbridge shares perform well relative to its peer organizations, the value of the longer-term incentive is maximized for the executives while also benefitting shareholders. The mix of longer-term incentive programs and total target longer-term incentive opportunity, expressed as a percentage of base salary, are as follows:

NEO	Total Target Longer-term Incentive Opportunity %	Performance Vested		Time Vested
		Performance Stock Units%	Performance-Based Stock Options%	Incentive Stock Options %
Stephen J.J. Letwin	150%	45%	60%	45%
Terrance L. McGill	65%	19.5%	—	45.5%
Stephen J. Wuori	150%	45%	60%	45%
Mark A. Maki	50%	15%	—	35%
Al Monaco	150%	45%	60%	45%

Actual award values, expressed as a percentage of base salary, may be zero to 150% of the target long-term incentive opportunity, based on individual performance history, succession potential, retention considerations and market competitiveness.

PSU Plan

The PSU Plan 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 zero to 200%. PSUs do not involve the issuance of any shares of stock of Enbridge. Awards are granted annually and paid in cash at the end of the three-year term based on the following:

	Number of PSUs Granted
+	Additional PSUs representing reinvested dividends had Enbridge shares been issued instead of PSUs
=	Total PSUs available for payout
x	Performance Multiplier (0-2) depending on the performance relative to criteria established at the time of grant
x	Market Value (as set forth in the grant) of an Enbridge share at the end of the term
=	$PSU award

For 2009, two performance criteria, each weighted 50%, were established for the grant: earnings per share ("EPS") and price to earnings ratio ("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 the long-range strategic plan and a growth rate that is 50% or more than the forecast average of peer companies. 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 75th percentile results in a multiplier of one and performance above the 75th percentile results in a multiplier of two. The following table presents the comparator group for the P/E ratio.

Price/Earnings Ratio – Comparator Group of Companies	
Oneok Inc.	TransCanada Corporation
Sempra Energy	Spectra Energy Corp.
PG&E Corp.	TransAlta Corp.
Centerpoint Energy Inc.	National Fuels Gas Corp.
Nisource Inc.	Canadian Utilities
Ameren Corp.	Fortis Inc.
OGE Energy Corp	Emera Inc.

This peer group of companies was selected because they are capital market competitors of Enbridge with a similar risk profile and in a comparable sector.

PBSO Plan

Performance stock options align the Enbridge executives, including Messrs. Letwin, Wuori 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 percent per year provided the performance criteria are met. Enbridge did not grant any performance stock options in 2009. Performance stock options were most recently granted to the executives in 2007 (and in 2008 to Mr. Monaco when he was appointed to the Enbridge executive team). The performance criteria for the 2007 performance stock options are Enbridge share price targets of $50 CAD and $55 CAD, which must be met by February 2014. The share price targets were determined from the Enbridge long-range plan and historic industry price to earnings ratio information. The approach used to determine the 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.

ISO Plan

Regular stock options focus the Enbridge executives on increasing shareholder value over the long-term through share price appreciation. Stock options are granted annually to Enbridge executives entitling them to acquire Enbridge 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.

Service Agreements and Allocation of Compensation to the Partnership

As discussed above, our general partner, Enbridge Management 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 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 two of the NEOs. 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 three of the NEOs. 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. For the year ended December 31, 2009, we were reimbursed approximately $2.5 million for allocations charged in excess of the approximate time spent on our matters by Mr. Letwin. There were no other adjustments recognized for the years ended December 31, 2009, 2008 and 2007, for amounts reimbursed to us by Enbridge and its affiliates for the portion of the NEOs' compensation allocated to us. For 2009, the percentage of time estimated to be spent by each of the NEOs on our matters was:

- Stephen J. J. Letwin – 30%
- Terrance L. McGill – 77%
- Stephen J. Wuori – 25%
- Mark A. Maki – 77%
- 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 STI Plan 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 2009, 2008 and 2007, 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, 2009, 2008 and 2007. 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 Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards[1] ($)	Option Awards[2] ($)	Non-Equity Incentive Plan Compen-sation[3] ($)	Change in Pension Value and Nonqualified Deferred Compen-sation Earnings[4] ($)	All Other Compen-sation[5] ($)	Total ($)	Approximate Percentage of Time Devoted to Enbridge Energy Partners, L.P. (%)	Approximate Amount Allocated to Enbridge Energy Partners, L.P. ($)
Stephen J.J. Letwin[6]	2009	540,000	—	856,452	699,542	530,000	518,000	95,385	3,239,379	30	971,814
Managing Director	2008	531,346	—	749,768	692,334	530,000	289,000	93,491	2,885,939	30	865,782
(Principal Executive Officer)	2007	483,750	—	325,947	570,647	450,000	335,000	91,003	2,256,347	30	676,904
Terrance L. McGill	2009	341,646	—	311,400	341,544	250,650	217,000	33,913	1,496,153	77	1,286,685
President	2008	343,170	—	199,550	312,806	244,910	140,000	33,228	1,273,664	85	1,113,428
	2007	323,631	—	111,869	148,725	241,320	128,000	38,835	992,380	84	815,977
Stephen J. Wuori[7][9]	2009	496,497	—	853,995	505,298	472,855	1,082,000	73,156	3,483,801	25	244,573
Executive Vice	2008	524,390	—	711,230	472,872	487,805	1,900,000	78,017	4,174,314	25	237,928
President Liquids Pipelines	2007	—	—	—	—	—	—	—	—		—
Mark A. Maki	2009	275,504	—	200,194	124,156	188,690	265,000	32,250	1,085,794	77	914,981
Vice President, Finance	2008	268,683	—	119,782	86,400	185,820	96,000	31,779	788,464	85	678,751
(Principal Financial Officer)	2007	258,681	—	70,850	67,217	161,170	103,000	31,513	692,431	84	577,011
Al Monaco[8][9]	2009	383,100	—	387,815	408,588	437,828	372,000	58,152	2,047,483	10	148,973
Executive Vice President	2008	367,417	—	325,028	223,681	361,163	124,000	55,210	1,456,499	—	—
Major Projects	2007	—	—	—	—	—	—	—	—	—	—

(1) The compensation expense associated with Performance Stock Units, or PSUs, for each NEO reflected in this column represents one-third of the grant date market value for each year the PSUs are outstanding and is measured based on the number of respective units granted, the percentage vested (33%) for each year, the actual or forecast performance multiplier and the market value. For example 2009 includes one-third of the grant date market values for PSUs issued in 2009, 2008 and 2007. In 2009, the compensation expense recorded for PSUs granted in 2009, 2008 and 2007 include performance multipliers for the respective years, which are estimated for 2009 and 2008 and actual for 2007 based upon the expected or achieved levels of performance in relation to established targets for each year. For years prior to the year a payout is made, a performance multiplier of 1.0 is assumed unless the actual multiplier has been determined. Refer also to footnote 2 of the "Grants of Plan-Based Awards" table for additional discussion regarding the PSUs.

The market value for each PSU grant represents the weighted average closing price of an Enbridge Share as quoted on the New York Stock Exchange, or NYSE, for the U.S. dollar (USD) denominated PSUs and the Toronto Stock Exchange, or TSX, for Canadian dollar (CAD) denominated PSUs for the 20 consecutive days prior to the end of the performance period. PSUs granted for 2009, 2008 and 2007 were denominated in both USD and CAD. The PSU expense in CAD is converted to USD based on the average exchange rate for the 20 trading days prior to the measurement date. The PSUs were granted on January 1, 2009, 2008 and 2007, respectively. Compensation expense as reported in the Summary Compensation Table above for Stock Awards has been determined using the following assumptions:

	2009	2008	2007	2006	2005
End of Period Market Value USD	$ 44.82	$ 31.40	$ 38.94	$ 34.73	N/A
End of Period Market Value CAD	$ 47.14	$ 38.71	$ 38.77	$ 38.65	$ 39.17
20-day average exchange rate	$ 1.0544	$ 1.2343	$ 1.0030	$ 1.1524	$ 1.1610
Exchange rate on payout date	N/A	N/A	N/A	$ 1.2241	$ 1.0120
Actual performance multiplier	N/A	N/A	2.00	2.00	0.71
Assumed performance multiplier	1.00	1.00	N/A	N/A	N/A

(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 (2002 and 2007) ("ISOP") and the Performance Stock Option Plan (2007) ("PSOP") are determined by computing the fair value of the options on the grant date using the Black-Scholes option pricing model for ISOPs and the Bloomberg barrier option valuation model for PSOPs. Enbridge did not grant any PSOPs to the NEOs during 2009. 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	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
Expected option term in years	6	6	6	N/A	8	8
Expected volatility	33.00% 1	9.90% 1	8.10%	N/A	13.60%	13.60%
Expected dividend yield	3.87%	3.08%	3.22%	N/A	3.32%	3.57%
Risk-free interest rate	2.31%	3.41%	4.11%	N/A	3.75%	4.38%

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 fair value of options granted under the PSOP as computed using the above assumptions is expensed over the vesting period. 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		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Exercise price in CAD	$ 39.61	$ 40.42	$ 38.26	N/A	$ 40.42	$ 36.57
Exercise price in USD	$ 31.59	$ 40.33	$ 32.59	N/A	$ 39.79	$ 34.03
Grant date exchange rate for $1 USD	$ 1.2556	$ 1.0160	$ 1.1740	N/A	$ 1.0160	$ 1.0746

	ISOP			PSOP		
	2009	**2008**	**2007**	**2009**	**2008**	**2007**
Vesting period in years	4	4	4	N/A	5	5
Option fair value on grant date in CAD	$ 6.73	$ 6.20	$ 6.16	N/A	$ 4.82	$ 3.40
Option fair value on grant date in USD	$ 6.86	$ 5.82	$ 5.25	N/A	$ 4.74	$ 3.16
Average exchange rate for $1 USD	$ 1.1420	$ 1.0660	$ 1.0748	N/A	$ 1.0660	$ 1.0748

(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 STI Plan as discussed in the above Compensation Discussion and Analysis.

(4) The 2008 amount reported as a change in pension value for Mr. Wuori has been increased by $1,428,000, to reflect retroactive benefit improvements for which he was eligible, but were not reflected in prior years.

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

(6) We made an adjustment in 2009 to the amounts reimbursed for Mr. Letwin's 2008 and 2007 compensation to reflect that 30% of his time was devoted to us. The amounts in the table for Mr. Letwin for 2008 were revised for the amount of the adjustment.

(7) 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 years ended December 31, 2009 and 2008 of $1.142 CAD = $1USD and $1.0660 CAD = $1 USD, respectively. The costs associated with the PSUs and options Mr. Wuori was granted in 2009 and 2008 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, Inc., or EPI, both subsidiaries of Enbridge.

(8) 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 years ended December 31, 2009 and 2008 of $1.142 CAD = $1 USD and $1.0660 CAD = $1 USD, respectively. The costs associated with the PSUs and options Mr. Monaco were granted in 2009 and 2008 were borne by Enbridge and other affiliates where he is also an officer.

(9) 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.

ALL OTHER COMPENSATION
(For the years ended December 31, 2009, 2008 and 2007)

Name	Year	Flexible Benefits[2] $	401(k) Matching Contributions[3] $	Relocation Allowance $	Mortgage Interest Payments $	Other Benefits[4] $	Total
Stephen J.J. Letwin	2009	35,000	12,250	—	44,275	3,860	95,385
	2008	35,000	11,500	—	43,371	3,620	93,491
	2007	35,000	11,250	—	40,321	4,432	91,003
Terrance L. McGill	2009	20,000	12,250	—	—	1,663	33,913
	2008	20,000	11,500	—	—	1,728	33,228
	2007	20,000	11,250	—	—	7,585	38,835
Stephen J. Wuori[1]	2009	62,500	—	—	274	10,382	73,156
	2008	66,694	—	—	—	11,323	78,017
Mark A. Maki	2009	20,000	12,250	—	—	—	32,250
	2008	20,000	11,500	—	—	279	31,779
	2007	20,000	11,250	—	—	263	31,513
Al Monaco[1]	2009	53,268	—	—	—	4,884	58,152
	2008	49,997	—	—	—	5,213	55,210

(1) The amounts reported in this table for Mr. Wuori and Mr. Monaco, our NEOs domiciled in Canada, have been converted from CAD to USD using the average exchange rate for the years ended December 31, 2009 and 2008 of $1.142 CAD = $1 USD and $1.0660 CAD = $1 USD, respectively.

(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 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 (b) 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 fifty percent of their base salary which is matched up to five percent by Enbridge. Both individual and matching contributions are subject to limits established by the Internal Revenue Service. Enbridge contributions are used to purchase Enbridge shares at market value and employee contributions may be used to purchase Enbridge shares or 23 designated funds.

(4) Other benefits include professional financial services, parking, home security and internet services.

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 payments in connection with recording the fair value of its 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 performance stock units are granted to the NEOs pursuant to the Enbridge Inc. Performance Stock Unit Plan and stock options are granted pursuant to the Enbridge Incentive Stock Option Plan (2007) and the Performance Stock Option Plan (2007). Awards under these plans provide long-term incentive and are administered by the Human Resources & Compensation 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 from 2004 through 2006 and stock option grants are denominated in CAD. The performance stock units granted in 2007 through 2009 to our U.S.-domiciled NEOs are denominated in USD while those granted to NEOs domiciled in Canada are denominated in Canadian dollars. The three tables which follow set forth information concerning performance stock units and stock options granted during the year ended December 31, 2009, outstanding at December 31, 2009 and the number of awards vested and exercised during the year ended December 31, 2009 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[5] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[2] Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Option Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options[3][4] (#) (j)	Exercise or Base Price of Option Awards[3][4] ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards[2][3][4] ($) (l)
Stephen J.J. Letwin	PSUP	5-Feb-08	1-Jan-08	—	—	—	6,250	10,000	20,000	—	—	—	314,000
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	60,000	31.59	411,600
	STIP	12-Feb-09	27-Feb-09	—	260,000	520,000	—	—	—	—	—	—	—
Terrance L. McGill	PSUP	5-Feb-08	1-Jan-08	—	—	—	2,500	4,000	8,000	—	—	—	125,600
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	49,500	31.59	339,570
	STIP	3-Feb-09	27-Feb-09	—	134,080	268,160	—	—	—	—	—	—	—
Stephen J. Wuori	PSUP	5-Feb-08	1-Jan-08	—	—	—	6,250	10,000	20,000	—	—	—	313,619
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	60,000	31.55	321,586
	STIP	12-Feb-09	27-Feb-09	—	248,261	496,522	—	—	—	—	—	—	—
Mark A. Maki	PSUP	5-Feb-08	1-Jan-08	—	—	—	1,563	2,500	5,000	—	—	—	78,500
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	30,100	31.59	206,486
	STIP	3-Feb-09	27-Feb-09	—	92,855	185,710	—	—	—	—	—	—	—
Al Monaco	PSUP	5-Feb-08	1-Jan-08	—	—	—	5,000	8,000	16,000	—	—	—	250,895
	ISOP	5-Feb-08	19-Feb-08	—	—	—	—	—	—	—	50,000	31.55	267,989
	STIP	12-Feb-09	27-Feb-09	—	197,033	394,065	—	—	—	—	—	—	—

(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 (2007), 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) Our NEOs are eligible to receive annual grants of Performance Stock Units, or PSUs, under the PSU Plan, 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 share as quoted on the Toronto Stock Exchange or New York Stock Exchange 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 share. Awards under the PSU Plan are paid out in cash at the end of a three-year performance cycle based on: (1) an earnings per share, or EPS, target for Enbridge based on the long range plan of the organization and (2) the price to earnings ratio of an Enbridge share relative to a defined group of peer organizations established in advance by a committee of the board of Enbridge. Payments under the PSU Plan may be increased up to 200 percent of the original award when Enbridge exceeds the established targets. If Enbridge fails to meet threshold performance levels, no payments are made under the PSU Plan. 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 shares in connection with the PSUP.

The threshold at which PSUs are issued represents 62.5 percent of the number of PSUs initially granted and is the lowest level at which PSUs will be issued based on the performance criteria discussed above. The target level at which PSUs are issued represents 100 percent of the number of PSUs initially granted and attainment of the established performance criteria. The maximum level at which PSUs may be issued is 200 percent 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 share with an assumed performance multiplier of one, 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 was $31.40 USD, representing the volume weighted average closing price of one Enbridge share as quoted on the New York Stock Exchange for the 20 trading days immediately preceding the start of the performance period that began on January 1, 2009. The grant date fair value for each PSU granted to each of our Canadian based NEOs was $38.71 CAD, representing the volume weighted average closing price of one Enbridge share as quoted on the Toronto Stock Exchange for the 20 days immediately preceding the start of the performance period that began on January 1, 2009. We have converted the grant date fair value for the Canadian PSU grants made from CAD to USD using an exchange rate of $1.2343 CAD = $1 USD, representing the weighted average noon rate for 20 trading days immediately preceding the performance period that began on January 1, 2009.

(3) The Enbridge Incentive Stock Option Plan (2007) 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 share on the Toronto

Stock Exchange or New York Stock Exchange 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 Toronto Stock Exchange or New York Stock Exchange for the day immediately preceding the grant date. During 2009, 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 $39.61 CAD for Canadian domiciled NEOs and $31.59 USD for NEOs domiciled in the United States.

The amounts included as the grant date fair value for the 2009 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;
33% expected volatility;	26.8% expected volatility;
3.87% expected dividend yield; and	3.88% expected dividend yield; and
2.31% risk free interest rate.	2.22% risk free interest rate.

The fair value of options granted as computed using these assumptions is $6.86 USD or $6.73 CAD. The $6.73 CAD option value and the $39.61 CAD exercise price have been converted to USD using an exchange rate of $1.2556 CAD = $1 USD representing the noon buying rate in New York for transfers of CAD on the grant date of February 25, 2009. The grant date fair value is expensed over the shorter of the vesting period for the options, generally 4 years, and the period to early retirement eligibility. Mr. Letwin and Mr. McGill are both within three years of early retirement eligibility and as a result the grant date fair value of options they are awarded is expensed in the year granted.

(4) The Enbridge Performance Stock Option Plan (2007) is administered by a committee of the Enbridge board of directors 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 share on the Toronto Stock Exchange or New York Stock Exchange 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 Toronto Stock Exchange or New York Stock Exchange for the day immediately preceding the grant date. Performance-based stock options, or PBSOs, are similar to the incentive stock options, except that the quantities become exercisable subject to both the achievement of specified share price targets and time requirements.

One half of the PBSOs become exercisable if the first share price hurdle is achieved and 100% of the grant becomes exercisable if the second share price hurdle is achieved within a 6 1/2 year time period. The term of each grant is 8 years provided the performance criteria are met. PBSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge share for each option held when the specified term and share price targets are met. The grant date fair value is expensed over the shorter of the vesting period for the options (generally 5 years) and the period to early retirement eligibility. Enbridge did not grant PBSOs to any of the NEOs during the year ended December 31, 2009.

(5) The estimated future payouts under non-equity incentive award plans represents awards under the Enbridge STI Plan as presented above in the Compensation Discussion and Analysis under the section labeled *Short-Term Incentive Plan*.

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)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date[(1)] (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested[(3)] (#) (i)	Equity Incentive Plan Awards: Market or Payout of Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
Stephen J.J. Letwin	—	60,000	—	31.59	25-Feb-19	—	—	10,367	958,345
	15,000	45,000	—	40.33	19-Feb-18	—	—	9,637	890,809
	22,500	22,500	—	32.59	9-Feb-17				
	40,275	13,425	—	31.58	13-Feb-16				
	13,100	—	—	25.49	3-Feb-15				
	—	330,000	—	34.03	15-Aug-15				
Terrance L. McGill	—	49,500	—	31.59	25-Feb-19	—	—	4,147	383,338
	12,375	37,125	—	40.33	19-Feb-18	—	—	3,426	316,732
	8,200	8,200	—	32.59	9-Feb-17				
	14,175	4,725	—	31.58	13-Feb-16				
	20,400	—	—	25.49	3-Feb-15				
	40,000	—	—	19.30	4-Feb-14				
	36,400	—	—	13.69	6-Feb-13				
Stephen J. Wuori	—	60,000	—	31.55	25-Feb-19	—	—	10,372	963,903
	15,000	45,000	—	39.79	19-Feb-18	—	—	9,637	895,621
	22,500	22,500	—	32.59	9-Feb-17				
	36,225	12,075	—	31.58	13-Feb-16				
	45,800	—	—	25.49	3-Feb-15				
	—	330,000	—	34.03	15-Aug-15				
	39,000	—	—	19.30	4-Feb-14				
	80,000	—	—	13.69	6-Feb-13				
	80,000	—	—	13.68	5-Feb-12				
	100,000	—	—	14.63	16-Sep-10				
Mark A. Maki	—	30,100	—	31.59	25-Feb-19	—	—	2,592	239,586
	7,525	22,575	—	40.33	19-Feb-18	—	—	2,034	188,060
	5,750	5,750	—	32.59	9-Feb-17				
	8,325	2,775	—	31.58	13-Feb-16				
	11,400	2,850	—	25.49	3-Feb-15				
	21,000	—	—	19.30	4-Feb-14				
	20,000	—	—	13.69	6-Feb-13				
Al Monaco	—	50,000	—	31.55	25-Feb-19	—	—	8,298	771,123
	11,250	33,750	—	39.79	19-Feb-18	—	—	7,496	696,594
	3,550	10,650	—	32.59	9-Feb-17				
	8,150	8,150	—	31.58	13-Feb-16				
	14,100	4,700	—	25.49	3-Feb-15				
	—	250,000	—	39.79	15-Aug-15				
	27,400	—	—	19.30	4-Feb-14				
	24,000	—	—	13.69	6-Feb-13				
	12,000	—	—	13.68	5-Feb-12				
	12,000	—	—	12.43	21-Feb-11				
	4,000	—	—	9.12	23-Feb-10				

(1) Each incentive stock option, or ISO, award has a 10-year term and vests prorata 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. Letwin's grant that expires on February 19, 2018, the grant date would be ten years prior or February 19, 2008 and as a result, the remaining unexercisable amounts become fully vested on February 19, 2012 representing 4 years following the grant date.

(2) Performance-based stock options, or PBSOs, were provided to certain of our NEOs on September 16, 2002, August 15, 2007 and February 19, 2008 and are similar to the incentive stock options, except that the quantity that become exercisable are subject to both time and performance requirements. PBSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge 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 percent of the grant, when the price of an Enbridge Share exceeded $30.50 for 20 consecutive days during the period September 16, 2002 to September 16, 2007, and became exercisable as to 100 percent when the price of an Enbridge 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 8 years expiring on September 16, 2010. In addition to the performance hurdles, the PBSOs are also time vested 20% annually over 5 years. As of December 31, 2007, 100 percent of the PBSOs granted September 16, 2002, had vested and were exercisable and none of the PBSOs granted August 15, 2007 and February 19, 2008 were vested or exercisable.

(3) The unearned shares, units or other rights that have not vested under stock awards represent PSUs for which the performance criteria discussed in footnote number 2 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 share price of one Enbridge share on the New York Stock Exchange at $46.22 per share or the Toronto Stock Exchange at $48.63 per share converted to USD of $46.46 per share at the conversion rate of $1.0466 CAD = $1 USD. The values presented assume a performance multiplier of 2.0 for PSUs granted in 2009 and 2008 which amounts represent the maximum level attainable based on forecasts of performance at December 31, 2009.

(4) The exercise prices of the ISOs and PBSOs issued during 2006 and prior years are denominated in CAD. 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 USD/CAD	Option Exercise Price USD
February 23, 2000	$ 13.3500	$ 0.6829	$ 9.1167
February 21, 2001	19.1000	0.6508	12.4303
February 5, 2002	21.8500	0.6259	13.6759
September 16, 2002	23.1500	0.6319	14.6285
February 6, 2003	20.8250	0.6572	13.6862
February 4, 2004	25.7200	0.7504	19.3003
February 3, 2005	31.6800	0.8046	25.4897
February 13, 2006	36.4700	0.8660	31.5830
February 9, 2007	38.2600	0.8519	32.5937
August 15, 2007	36.5700	0.9306	34.0320
February 19, 2008	40.4200	0.9843	39.7854
February 25, 2009	39.6100	0.7964	31.5467

OPTION EXERCISES AND STOCK VESTED

Name	Option Awards		Stock Awards	
	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise[3] ($)	Number of Shares Acquired on Vesting[1] (#)	Value Realized on Vesting[2] ($)
Stephen J.J. Letwin	—	—	9,962	893,052
Terrance L. McGill	—	—	3,542	317,530
Stephen J. Wuori	—	—	9,963	897,436
Mark A. Maki	38,400	653,434	2,324	208,379
Al Monaco	16,000	312,606	3,100	279,202

(1) The number of shares acquired on vesting for stock awards represents the number of PSUs issued in 2007 and the related dividends paid that were used to acquire additional PSUs, all of which matured on December 31, 2009. As discussed in footnote number 2 of the Grants of Plan-Based Awards table, no 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 share at the maturity date and the level of achievement of the established performance goals. The payout for the PSUs granted in 2007 is expected to occur on or about March 15, 2010.

(2) The value realized on vesting is determined based on the final value of an Enbridge share of $44.82USD for the NEOs domiciled in the U.S. or $47.14CAD for the NEOs domiciled in Canada. In each case the 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 $1.0466CAD = $1USD for the PSUs that matured on December 31, 2009.

The value realized on the exercise of options by Mr. Maki has been converted to USD using an exchange rate of $1.0999CAD = $1USD for 25,000 options exercised on June 1, 2009 and an exchange rate of $1.0551CAD = $1USD for 13,400 options exercised on November 18, 2009.

The value realized on the exercise of options by Mr. Monaco has been converted to USD using an exchange rate of $1.1853CAD = $1USD for 6,000 options exercised on January 2, 2009 and an exchange rate of $1.1327CAD = $1USD for 10,000 options exercised on June 11, 2009.

Pension Plan

Enbridge sponsors two basic pension plans, the Retirement Plan for Employees' Annuity Plan, or EI RPP, and the Enbridge Employee Services, Inc. Employees' Annuity Plan, or QPP, which provide defined pension benefits and cover employees in Canada and the United States, respectively. Both plans are non-contributory. Enbridge also sponsors supplemental nonqualified retirement plans in both Canada ("EI SPP") and the United States ("US SPP"), which provide 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." Retirement benefits under the Pension Plans are based on the employees' years of service and final average remuneration with an offset for Social Security benefits. These 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 after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 1.6 percent 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, 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 percent of the participant's Social Security benefit, prorated 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 Plan are indexed at 50 percent of the annual increase in the consumer price index. 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 after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 2 percent 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 percent 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 percent of the annual increase in the consumer price index.

The table below illustrates the total annual pension entitlements at December 31, 2009 assuming the eligibility requirements for an unreduced pension have been satisfied. We have converted pensions payable in CAD into USD at the rate of $1.0466 CAD = $1.00 USD an approximate average of the exchange rate during 2009. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	5.80% at year end 2009
Salaries	Current
Inflation	2.50% per year
Retirement age	Age when first eligible for an unreduced pension[1]
Terminations	None
Mortality	
Pre-retirement	None
Post-retirement	PPA generational annuitant and nonannuitant tables (RP 2000 projected to 2005 at year end 2007)

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

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

Mr. Letwin was granted six additional years of credited service on his employment date based on the pension formula applicable for service prior to January 1, 2000.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
Stephen J.J. Letwin	EI RPP	7.08	205,000	—
	EI SPP	13.08	1,834,000	—
	QPP	3.67	160,000	—
	US SPP	3.67	472,000	—
Terrance L. McGill	US QPP	7.50	135,000	—
	US SPP	7.83	701,000	—
Stephen J. Wuori	EI RPP	15.67	562,000	—
	EI RPP	15.67	4,862,000	—
	US QPP	13.83	238,000	—
	US SPP	13.83	60,000	
Mark A. Maki	EI RPP	1.92	48,000	—
	EI SPP	1.92	71,000	—
	US QPP	21.40	807,000	—
	US SPP	21.40	290,000	—
Al Monaco	EI RPP(1)	14.08	285,000	—
	EI SPP	11.08	745,000	—

(1) 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 has entered into an executive employment agreement with each of Stephen J.J. Letwin, Managing Director and Chief Executive Officer of Enbridge Management and our general partner, Stephen J. Wuori, Executive Vice President—Liquids Pipelines of Enbridge Management and our general partner, and Al Monaco, Executive Vice President—Major Projects of Enbridge Management and our general partner. The agreements for Messrs. Letwin and 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. 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. Neither Mr. McGill nor Mr. Maki has an employment agreement with us or any other Enbridge affiliate.

Each of the agreements provides that Enbridge will pay severance benefits to each of Mr. Letwin, Mr. Wuori and Mr. Monaco as set forth in the table below, except as noted below in respect of Mr. Monaco's 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 or 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 does 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 upon the occurrence of one of the foregoing events:

<table>
<tr><th>Type of Termination</th><th>Base Salary</th><th>Short-Term Incentive</th><th>Longer-term Incentives</th><th>Benefits</th><th>Pension</th></tr>
<tr><td>Resignation</td><td>None</td><td>Payable in full if entire calendar year is worked. Otherwise none.</td><td>Performance options are pro-rated based on resignation date. Vested options must be exercised within 30 days post the resignation or the original term, whichever is shorter. Unvested options are cancelled. Performance units are forfeited.</td><td>None</td><td>Credited service no longer earned.</td></tr>
<tr><td>Retirement</td><td>None</td><td>Incentive for current year is pro-rated based on retirement date</td><td>Performance options are pro-rated based on retirement date. Options continue to vest and remain exercisable for 3 years post the retirement date or the original term, whichever is shorter. Performance units are pro-rated based on retirement date.</td><td>Post retirement benefits begin.</td><td>Credited service no longer earned.</td></tr>
<tr><td>Involuntary Termination (Not for Cause)</td><td rowspan="3">2 years of Base salary in lump sum</td><td rowspan="3">Two times the average of short-term incentive awards received during the past two years plus the current year's short term incentive pro-rated based on service prior to the termination of employment.[1]</td><td rowspan="2">Vested options are exercisable in accordance with their terms[2] Value of the unvested options is paid in cash. Performance units are pro-rated based on employment termination date and the value is assessed and paid at the end of the term.</td><td rowspan="3">2 years of Benefits value in lump sum.</td><td rowspan="3">2 additional years of pension accrual added to final pension calculation.</td></tr>
<tr><td>Termination (Constructive Dismissal)</td></tr>
<tr><td>Termination (Change of Control)</td><td>All options vest. All performance units mature and value is assessed and paid based upon applicable performance measures achieved to that time.</td></tr>
</table>

Notes:

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.

In addition, the executive officer will receive:

- Up to a maximum of $10,000 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. Letwin and 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 Mr. Letwin, Mr. Wuori and Mr. 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 Mr. Letwin, Mr. Wuori or Mr. Monaco, Enbridge would owe incremental benefits with a value of approximately $9 million, $10 million and $6 million, respectively. Such amounts assume that termination was effective as of December 31, 2009, and as a result include amounts earned through such time and are estimates of the amounts which would be paid out to each of Mr. Letwin, Mr. Wuori and Mr. 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 Enbridge Energy Company, Inc., 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 percent 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.

Under the Director Compensation Plan, directors receive an annual retainer of $75,000 and no additional fees for attending regular meetings. Effective July 1, 2008, the annual retainer paid to the Chairman of the Board was increased by $15,000 and the annual retainer paid to the Chairman of the Audit Committee was increased by $10,000. The out of state travel fee is $1,500 per meeting. The Corporate Governance Guidelines provide an expectation that independent directors will hold a personal investment in either or both of us or Enbridge Management, of at least two times the annual board retainer, which currently would be $150,000 (i.e., 2 X $75,000 = $150,000). 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 January 30, 2009 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 by $5,000 for each assignment and that each member of the Special Committee should receive $1,500 per meeting.

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Jeffrey A. Connelly *Audit Committee Chairman*	120,000	—	—	—	—	—	120,000
Martha O. Hesse *Chairman of the Board*	108,000	—	—	—	—	—	108,000
George K. Petty	81,000	—	—	—	—	—	81,000
Dan A. Westbrook	96,000	—	—	—	—	—	96,000

The General Partner indemnifies each director for actions associated with being a director to the full 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/ STEPHEN J.J. LETWIN

Stephen J.J. Letwin
Managing Director and Director

/s/ TERRANCE L. MCGILL

Terrance L. McGill
President and Director

/s/ STEPHEN J. WUORI

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

/s/ JEFFREY A. CONNELLY

Jeffrey A. Connelly
Director

/s/ MARTHA O. HESSE

Martha O. Hesse
Director

/s/ GEORGE K. PETTY

George K. Petty
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 18, 2010, 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, Suite 3300 Houston, TX 77002	i-units	16,699,977	100.0
Enbridge Energy Company, Inc. 1100 Louisiana, Suite 3300	Class A common units	23,259,168	23.9
	Class B common units	3,912,750	100.0
Caisse de dépôt et placement du Québec 1000 Place Jean-Paul-Riopelle Montreal Quebec, Canada, H2Z 2B3	Class A common units	12,827,152	13.2

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 18, 2010, 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
Martha O. Hesse[5]	Class A common units	—	—	Listed Shares	26,886	*
Jeffrey A. Connelly[6]	Class A common units	7,000	*	Listed Shares	—	—
George K. Petty[2]	Class A common units	3,300	*	Listed Shares	3,322	*
Dan A. Westbrook[3]	Class A common units	9,500	*	Listed Shares	—	—
Stephen J.J. Letwin[4]	Class A common units	22,000	*	Listed Shares	—	—
Terrance L. McGill	Class A common units	2,000	*	Listed Shares	1,795	*
Stephen J. Wuori	Class A common units	—	—	Listed Shares	—	—
Richard L. Adams	Class A common units	—	—	Listed Shares	—	—
E. Chris Kaitson	Class A common units	—	—	Listed Shares	—	—
John A. Loiacono	Class A common units	1,000	*	Listed Shares	—	—
Mark A. Maki	Class A common units	1,500	*	Listed Shares	1,018	*
Al Monaco	Class A common units	—	—	Listed Shares	—	—
Stephen J. Neyland	Class A common units	—	—	Listed Shares	—	—
Kerry C. Puckett	Class A common units	1,000	*	Listed Shares	—	—
Jonathan N. Rose	Class A common units	—	—	Listed Shares	—	—
Allan M. Schneider	Class A common units	—	—	Listed Shares	—	—
Bruce A. Stevenson	Class A common units	—	—	Listed Shares	—	—
Leon A. Zupan	Class A common units	—	—	Listed Shares	—	—
All Officers, directors and nominees as a group (18 persons)	Class A common units	47,300	*	Listed Shares	33,021	*

* 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 3,300 Class A common units deemed beneficially owned by Mr. Petty, 683 of such Class A common units are held in an account of his aunt, for which Mr. Petty has been granted power-of-attorney to effect trades. Of the 3,322 Listed Shares deemed beneficially

owned by Mr. Petty, 1,035 Listed Shares are held in each of two Uniform Gifts to Minors Act custodial accounts for the benefit of two granddaughters. Mr. Petty is the custodian for each such account.

(3) Of the 9,500 Class A common units deemed beneficially owned by Mr. Westbrook, 8,000 Class A common units are held by The Westbrook Trust, for which Mr. Westbrook is the trustee and beneficiary, and 1,500 Class A common units are held by the Mary Ruth Trust, for which Mr. Westbrook is one of the trustees, along with his mother, who is also the beneficiary.

(4) Of the 22,000 Class A common units deemed beneficially owned by Mr. Letwin, 7,000 Class A common units are owned by Mr. Letwin's spouse.

(5) Of the 26,886 Listed Shares deemed beneficially owned by Ms. Hesse 21,233 Listed Shares are held by a pension plan established for her benefit and 5,548 Listed Shares are held in an Individual Retirement Account established for her benefit.

(6) Of the 7,000 Class A common units deemed beneficially owned by Mr. Connelly, 7,000 Class A common units are held in the Susan K. Connelly Family Trust of which Mr. Connelly is the trustee and a beneficiary.

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

INTEREST OF THE GENERAL PARTNER IN THE PARTNERSHIP

At December 31, 2009, our general partner had the following ownership interests in us:

	Quantity	Effective Ownership %
Direct ownership		
Class A common units representing limited partner interests	23,259,168	19.4%
Class B common units representing limited partner interests	3,912,750	3.3%
General Partner interest	—	2.0%
Indirect ownership		
Enbridge Management shares (Listed and Voting)	2,822,529	2.3%
Total effective ownership	29,994,447	27.0%

INTEREST OF ENBRIDGE MANAGEMENT IN THE PARTNERSHIP

At December 31, 2009, Enbridge Management owned 16,388,867 i-units, representing a 13.6% 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", 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 C units, prior to their conversion to Class A common units in October 2009, 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:

	Limited Partners	General Partner
Quarterly Cash Distributions per Unit:		
Up to $0.59 per unit	98%	2%
First Target—$0.59 per unit up to $0.70 per unit	85%	15%
Second Target—$0.70 per unit up to $0.99 per unit	75%	25%
Over Second Target—Cash distributions greater than $0.99 per unit	50%	50%

During 2009, we paid cash and incentive distributions to our general partner for its general partner ownership interest of approximately $57.0 million and cash distributions of $15.5 million in connection with its ownership of the Class B common units. The cash distributions we make to our general partner for its general partner ownership interest exclude an amount equal to two percent of the i-unit distributions and, prior to October 2009, the Class C unit distributions to maintain its two percent 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 2009, we distributed a total of 1,625,812 i-units to Enbridge Management and retained cash totaling approximately $61.1 million in connection with these in-kind distributions.

Prior to the conversion of the Class C units to Class A common units in October 2009, holders of our Class C units received quarterly distributions of additional Class C units with a value equal to the quarterly cash distribution we paid to the holders of our Class A and Class B common units. We determined the additional Class C units we issued by dividing the quarterly cash distribution per unit we paid on our Class A and Class B common units by the average market price of a Class A common unit as listed on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. In 2009, we distributed a total of 538,609 Class C units to our general partner in lieu of making cash distributions and retained cash totaling approximately $19.7 million in connection with these in-kind distributions.

GENERAL PARTNER CONTRIBUTIONS

Pursuant to our partnership agreement, our general partner is at all times required to maintain its two percent general partner ownership interest in us. During 2009, in connection with our issuance and sale in October 2009 of 21,245 Class A common units, our general partner contributed approximately $20,408 to us to maintain its two percent 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.

Service Agreements

As discussed in "Compensation Discussion and Analysis—Service Agreements and Allocation of Compensation to the Partnership", 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. 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 EES, Inc., a subsidiary of our general partner, we are charged for the services of employees resident in the United States.

Operational Services Agreement

With respect to services provided under the operational services agreement, as part of the annual budget process, we and the Canadian service providers agree on the amount to be allocated to us, which is 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. 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.

Once the allocation is completed, management of our general partner and Enbridge Management evaluate and review the reasonableness of the amount and discuss it with management of the Canadian service providers. Together, they determine the reasonableness of the allocation amount as part of the annual budget review process. In addition, the allocation amounts are included in the presentation materials provided to the boards of directors of Enbridge Management and our general partner for their approval. Once approved by the boards of directors, this amount becomes the fixed fee that will be charged in fixed monthly amounts to us, our general partner and Enbridge. Each month, we reimburse the Canadian service providers for the scheduled monthly fixed fee. This fixed fee includes a portion of the compensation costs of individuals that serve as officers and directors of our general partner and Enbridge Management in managing our business and affairs, including the NEOs as discussed in Item 11. *Executive Compensation.*

The total amount reimbursed by us pursuant to the operational services agreement for the years ended December 31, 2009, 2008 and 2007 were $63.4 million, $62.3 million and $49.0 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. Enbridge (U.S.) Inc. is also a party to this agreement. Under this agreement, EES provides services to us, Enbridge Management and our general partner and charges each recipient of 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 U.S. Enbridge entity but are shared among multiple U.S. 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 cost center allocations charged to us as described above include a portion of the compensation costs for individuals who serve as officers and directors of our general partner and Enbridge Management in managing our business and affairs, including the NEOs as discussed in Item 11. *Executive Compensation.*

The total amount reimbursed by us pursuant to the general and administrative services agreement for the years ended December 31, 2009, 2008 and 2007 were $225.8 million, $207.5 million and $181.6 million, respectively.

EUS Credit Facility

In April 2009, we entered into a $150 million unsecured and non-guaranteed revolving credit facility agreement with Enbridge (U.S.) Inc., which we terminated in December 2009 as discussed in Note 10-Debt-364-day Credit Facilities in the consolidated financial statements beginning on page F-2 of this Annual Report on Form 10-K. We incurred debt origination fees in connection with establishing this facility totaling $1.5 million, which we paid to Enbridge (U.S.) Inc. during 2009.

Hungary Note Payable

In November 2009, we repaid the $130.0 million outstanding balance of our notes payable to Enbridge Hungary Ltd., an affiliate of our general partner, referred to as the Hungary Note. At December 31, 2009 we had no amounts outstanding under the Hungary Note, and paid a total of $9.3 million and $10.9 million for the years ended December 31, 2009 and 2008, respectively, at a fixed rate of 8.4% per annum.

EUS Credit Agreement

In December 2007, we entered an unsecured revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge, referred to as the EUS Credit Agreement. Enbridge is the indirect owner of Enbridge Energy Company, Inc., our general partner. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Credit Facility as discussed above. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Credit Facility. At December 31, 2009, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use. During 2009 we paid facility fees totaling $0.5 million to Enbridge (U.S.) Inc. associated with the EUS Credit Agreement.

Joint Funding Arrangement for Alberta Clipper Project

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Project, with several of our affiliates and affiliates of Enbridge. This joint funding arrangement is pursuant to a Contribution Agreement by and among our general partner, Enbridge Pipelines (Alberta Clipper) L.L.C., the OLP, Enbridge Energy Partners, L.P., Enbridge Pipelines (Lakehead) L.L.C., and Enbridge Pipelines (Wisconsin) Inc. Under the terms of the Contribution Agreement, the parties have agreed to jointly fund, construct and operate the Alberta Clipper Project. To effect the provisions of the Contribution Agreement, the limited partnership agreement for the OLP, was amended and restated to establish two distinct series of partnership interests. All the assets, liabilities and operations related to the Alberta Clipper Project are designated specifically by the Series AC interests while all other assets and operations of the OLP are designated by the Series LH interests. Liabilities of the OLP have recourse to both the Series AC and Series LH assets. In exchange for a 66.67 percent ownership interest in the Series AC interests, Enbridge, through our general partner, is funding approximately two-thirds of both the debt financing and equity requirement for the Alberta Clipper Project in return for approximately two-thirds of the Alberta Clipper Project's earnings and cash flows. The 66.67 percent ownership interest of our general partner in the Series AC interests and the earnings and cashflows attributable to this interest are presented as the balance and activities of the noncontrolling interest in our consolidated financial statements. For our 33.33 percent ownership of the Series AC interests we are funding approximately one-third of the debt financing and required equity of the Alberta Clipper Project, for which we are entitled to approximately one-third of the project's earnings and cash flows. We and our general partner each have a right of first refusal on the other's investment in the Alberta Clipper Project, and we retain the right to fund up to 100 percent of any expansion of the Alberta Clipper Project, which would result in a corresponding adjustment of our general partner's interest.

The funding of the construction costs for the Alberta Clipper Project provided by our general partner are facilitated through a newly established credit facility with us, which we refer to as the A1 Credit Agreement, as well as capital contributions directly by the Series AC holders. The A1 Credit Agreement will be used to fund Enbridge's debt portion of project costs during construction. The A1 Credit Agreement is an unsecured, non-revolving credit facility with a capacity of $400 million and will be utilized for the purpose of funding capital expenditures that are directly related to the Alberta Clipper Project and to refinance the existing indebtedness previously incurred to fund such costs.

Under the A1 Credit Agreement, project expenditures are funded through either a Base Rate Loan or Fixed Period Eurodollar Rate Loan as those terms are defined in the A1 Credit Agreement. Funds drawn under the Base Rate Loan bear interest at a base rate that is equal to the greater of (a) the Federal Funds Rate plus one half of one percent or (b) the "Prime rate" as determined by Bank of America, N.A., from time to time. Funds drawn under Fixed Period Eurodollar Rate Loans will bear interest at a rate per annum equal to the BBA LIBOR plus an additional rate per annum based on the credit rating of our senior unsecured long-term debt as determined by Standard & Poor's Financial Services LLC and Moody's Investors Service, which we respectively refer to as S&P and Moody's. Any interest incurred and outstanding is due on the last business day of March, June, September and December and the maturity date for both the Based Rate and Fixed Period Eurodollar Rate loans.

The A1 Credit Agreement contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.25 to 1.0 for periods ending on or before March 31, 2010 and a maximum ratio of 5.0 to 1.0 for periods ending June 30, 2010 and thereafter. At December 31, 2009, our leverage ratio was approximately 3.43 as computed pursuant to the terms of the A1 Credit Agreement. The A1 Credit Agreement also places limitations on the debt that our subsidiaries may incur directly. Accordingly, we are expected to provide debt financing to our subsidiaries as necessary.

The maturity date of the A1 Credit Agreement is the earlier of July 1, 2011 or the date that is 180 days following the in-service date of the U.S. portion of the Alberta Clipper crude oil pipeline. At points of time either shortly before or shortly after the in-service date for the Alberta Clipper Project, we must use commercially reasonable efforts to issue debt in one or more capital market transactions, the proceeds of which will be used to refinance the loans we make to the OLP on substantially the same terms as the debt issued in the capital market transactions. On the same date, our general partner will refinance its loans with respect to the project on substantially the same terms as we refinanced our loan to the OLP. Repayment of any principal amount outstanding on the A1 Credit Agreement is required on the maturity date. The A1 Credit Agreement allows for the prepayment of borrowings prior to the scheduled maturity date without penalty. The A1 Credit Agreement is limited in recourse only to the Series AC assets. At December 31, 2009, we had $269.7 million outstanding under the A1 Credit Agreement bearing interest at a weighted average rate of 0.548% per annum. We incurred interest costs totalling $1.5 million under the terms of the A1 Credit Agreement during the year ended December 31, 2009. Our general partner also made equity contributions totaling $329.7 million to the OLP for the year ended December 31, 2009, to fund its equity portion of the construction costs associated with the Alberta Clipper Project. In addition, we allocated $11.4 million of earnings to our general partner for its 66.67 percent of the earnings of the Alberta Clipper Project derived from the allowance for equity during construction, which is presented in our consolidated statements of income as "Net income attributable to noncontrolling interest."

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 2009, 2008 and 2007 was approximately $0.8 million, $0.7 million and $0.6 million, respectively.

Asset Purchase and Sale Transactions with Affiliates

Purchase of Line Pipe

We, our general partner and Enbridge Pipelines regularly collaborate on construction projects that are mutually beneficial to our respective customers and operations. Examples of such projects include the Southern Access and Alberta Clipper crude oil pipeline projects where we have constructed and are constructing the U.S. portion of the projects and Enbridge Pipelines has constructed and is constructing the Canadian portion. In March 2009, we acquired, for $27.0 million, approximately 25 miles of 36-inch diameter line pipe from our general partner. Both purchases were for our use in constructing the Alberta Clipper Project. The line pipe was initially obtained by our general partner for use in constructing the Southern Access extension, which has been delayed due to a protracted regulatory process. The transactions were previously approved by the Enbridge Management Board of Directors.

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 Project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. For the year ended December 31, 2009 we paid $19.3 million in lease payments. The transfer and lease became effective February 20, 2009, which was the in-service date for the light sour pipeline. The lease of Line 13 will be effective until the earliest of (i) July 1, 2010, (ii) upon the transfer of the Canadian portion of Line 13 from Enbridge Pipelines to Enbridge Southern Lights LP, a wholly-owned subsidiary of Enbridge Pipelines or (iii) early termination of the lease. We are able to terminate the lease at any time during the term by providing Southern Lights with written notice, at which time we would be required to return Line 13 to Southern Lights. The costs associated with the lease are being recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow over the life of the transaction is expected to approximate zero. The exchange resulted in a $166.5 million increase in "Property, plant and equipment" 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. Subsequent to the initial exchange, an additional $5.8 million of costs were incurred by Southern Lights through December 31, 2009 that have been transferred to us through the capital account of our general partner, which are included in the $171.5 million cost presented above. 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.

Spearhead Pipeline Acquisition

In May 2009, we purchased a portion of a crude oil pipeline system from CCPS Transportation, L.L.C., a wholly-owned subsidiary of our general partner, for approximately $75 million, representing the carrying value in the records of our general partner. The portion of the system, which we refer to as Spearhead North, includes approximately seven storage tanks and 75 miles of pipeline that our general partner reversed to provide northbound service from Flanagan to Griffith. The acquisition of Spearhead North complements the existing operations of our Lakehead system, as our newly-constructed Southern Access pipeline ends in Flanagan where it connects to Spearhead North. The transaction was previously approved by the Enbridge Management Board of Directors.

Private Issuance of Class A Common units to General Partner

In October 2009, the Class C units converted on a one-for-one basis, into 21,333,273 Class A common units, with a cash payment of $123.21 made to the holders for the 2.608092 remaining fractional units. In order to facilitate the conversion of the Class C units, we issued and sold 21,245 Class A common units to our general partner in a private placement for $47.07 per unit, or approximately $1 million, in order for the general partner to maintain its two percent general partner interest. The Class A common units represent limited partner ownership interests in the Partnership and the General Partner's ownership in the Partnership of approximately 27 percent remained the same.

For further discussion of these and other related party transactions, refer to Note 12—*Related Party Transactions* in the consolidated financial statements beginning on page F-2 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 2009, 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 Michigan office as the Manager, Origination. During 2009, she received total cash compensation of $190,303.45 and benefits estimated at approximately 38% of her base compensation for a total of $239,703.45.

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 years ended December 31,	
	2009	2008
Audit fees[1]	$ 2,330,500	$ 2,566,000
Audit related fees[2]	—	792,000
Tax fees[3]	600,000	742,500
Total	$ 2,930,500	$ 4,100,500

[1] Audit fees consist of fees billed for professional services rendered for the audit of our consolidated financial statements, reviews of our interim consolidated financial statements, audits of various subsidiaries for statutory and regulatory filing requirements and our debt and equity offerings.

[2] Preliminary financial due diligence and audit services in connection with a transaction that the Partnership had been considering during 2008.

[3] 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, Finance & Risk Committee of Enbridge Management's board of directors; however, services up to $50,000 may be approved by the Chairman of the Audit, Finance & Risk Committee, under the board of directors' delegated authority. All services in 2009 and 2008 were approved by the Audit, Finance & Risk Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as a part of this report:

(1) *Financial Statements, which are incorporated by reference in Item 8 are included beginning on page F-1.*

a. Report of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

b. Consolidated Statements of Income for the years ended December 31, 2009, 2008, and 2007.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2009, 2008, and 2007.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008, and 2007.

e. Consolidated Statements of Financial Position as of December 31, 2009 and 2008.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2009, 2008, and 2007.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

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

(3) *Exhibits.*

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

SIGNATURES

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

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

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

By: /S/ STEPHEN J.J. LETWIN
Stephen J.J. Letwin
(Managing Director)

Date: February 18, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on February 18, 2010 by the following persons on behalf of the Registrant and in the capacities indicated.

/S/ STEPHEN J.J. LETWIN
Stephen J.J. Letwin
Managing Director
(Principal Executive Officer)

/S/ MARK A. MAKI
Mark A. Maki
Vice President—Finance
(Principal Financial Officer)

/S/ TERRANCE L. MCGILL
Terrance L. McGill
President and Director

/S/ STEPHEN J. NEYLAND
Stephen J. Neyland
Controller

/S/ STEPHEN J. WUORI
Stephen J. Wuori
Executive Vice President—Liquids Pipelines and Director

/S/ JEFFREY A. CONNELLY
Jeffrey A. Connelly
Director

/S/ MARTHA O. HESSE
Martha O. Hesse
Director

/S/ GEORGE K. PETTY
George K. Petty
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(c) 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).
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	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).
10.2	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).
10.3	Contribution Agreement (incorporated by reference to Exhibit 10.1 of our Registration Statement on Form S-3/A filed on July 8, 2002).
10.4	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).
10.5	Second Amendment to Contribution Agreement (incorporated by reference to Exhibit 99.3 of our Current Report on Form 8-K filed on October 31, 2002).
10.6	Delegation of Control Agreement (incorporated by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q filed on November 14, 2002).
10.7	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).
10.8	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).
10.9	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of our Quarterly Report on Form 10-Q filed on November 14, 2002).

Exhibit Number	Description
10.10	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).
10.11	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of our Quarterly Report on Form 10-Q filed on November 14, 2002).
10.12	Second Amended and Restated Credit Agreement, dated April 4, 2007, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on April 10, 2007).
10.13	First Amendment to Second Amended and Restated Credit Agreement among the Partnership, as Borrower, the Lenders party thereto, Bank of America, N.A., as Administrative Agent and Swing Line Lender, and Bank of America, N.A. and Wachovia Bank, National Association, as L/C Issuers dated March 27, 2009 (incorporated by reference to Exhibit 10.1 of our Quarterly Report on Form 10-Q filed on May 5, 2009).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	Commercial Paper Dealer Agreement between the Partnership, as Issuer, Merrill Lynch, Pierce, Fenner, and Smith Incorporated and Merrill Lynch Money Markets Inc., as Dealer, dated April 21, 2005 (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed on May 3, 2005).
10.19	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).
10.20	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).
10.21	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).
10.22	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).
10.23	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).
10.24	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).

Exhibit Number	Description
10.25	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).
10.26	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).
10.27	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).
10.28	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).
10.29+	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).
10.30+	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).
10.31+	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.27 of our Annual Report on Form 10-K filed on March 28, 2003).
10.32+	Executive Employment Agreement between Enbridge Inc. and Al Monaco dated January 9, 2008 (incorporated by reference to Exhibit 10.2 of our Quarterly Report on Form 10-Q filed on May 5, 2009).
10.33+	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).
10.34+	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).
10.35+	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).
10.36+	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).
10.37	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).
10.38	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).
10.39	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).
10.40	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).
10.41	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).

Exhibit Number	Description
10.42	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).
10.43	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).
10.44	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).
10.45	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).
10.46	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).
10.47	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 dated September 28, 2007).
10.48	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).
10.49	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 dated September 28, 2007).
10.50	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of our Current Report on Form 8-K filed on February 10, 2005).
10.51	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).
10.52	Credit Agreement among the Partnership, as Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, and Export Development Canada, as Documentation Agent, dated April 9, 2009 (incorporated by reference to Exhibit 10.3 of our Quarterly Report on Form 10-Q filed on May 5, 2009).
10.53	Credit Agreement among the Partnership, as Borrower, Enbridge U.S. and the other Lenders party thereto and Enbridge U.S., as Administrative Agent, dated April 9, 2009 (incorporated by reference to Exhibit 10.4 of our Quarterly Report on Form 10-Q filed on May 5, 2009).
10.54	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).
10.55	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).
10.56	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).
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).

Exhibit Number	Description
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of PricewaterhouseCoopers LLP.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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.

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 and 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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 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.

PricewaterhouseCoopers LLP

Houston, Texas
February 18, 2010

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the year ended December 31,		
	2009	2008	2007
	(in millions, except per unit amounts)		
Operating revenue (Note 14)	$ 5,731.8	$ 9,898.7	$ 7,172.1
Operating expenses			
Cost of natural gas (Notes 6 and 15)	4,180.8	8,454.5	6,176.0
Operating and administrative	548.6	513.0	408.8
Power	128.1	140.7	117.0
Depreciation and amortization (Note 7)	257.7	209.9	151.9
	5,115.2	9,318.1	6,853.7
Operating income	616.6	580.6	318.4
Interest expense (Notes 10, 12 and 15)	228.6	180.6	99.8
Other income (Note 18)	13.4	1.9	4.2
Income from continuing operations before income tax expense	401.4	401.9	222.8
Income tax expense (Note 16)	8.5	7.0	5.1
Income from continuing operations	392.9	394.9	217.7
Income (loss) from discontinued operations, net of tax (Note 3)	(64.9)	8.3	31.8
Net income	328.0	403.2	249.5
Less: Net income attributable to noncontrolling interest (Note 12)	11.4	—	—
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 316.6	$ 403.2	$ 249.5
Net income allocable to limited partner interests			
Income from continuing operations	$ 324.4	$ 345.4	$ 181.5
Income (loss) from discontinued operations	(63.6)	8.1	31.2
Net income allocable to limited partner interests	$ 260.8	$ 353.5	$ 212.7
Basic and diluted earnings per limited partner unit (Note 4)			
Income from continuing operations	$ 2.78	$ 3.55	$ 2.10
Income (loss) from discontinued operations	(0.54)	0.09	0.36
Net income per limited partner unit (basic and diluted)	$ 2.24	$ 3.64	$ 2.46
Weighted average limited partner units outstanding	116.4	97.1	86.3
Cash distributions paid per limited partner unit outstanding	$ 3.960	$ 3.880	$ 3.725

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,		
	2009	2008	2007
		(in millions)	
Net income	$ 328.0	$ 403.2	$ 249.5
Other comprehensive income (loss), net of tax benefit (expense) of $0.6, $(1.8) and $0.7, respectively (Note 15)	(87.5)	307.3	(104.8)
Comprehensive income	240.5	710.5	144.7
Less: Comprehensive income attributable to noncontrolling interest (Note 12)	11.4	—	—
Comprehensive income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 229.1	$ 710.5	$ 144.7

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,		
	2009	2008	2007
		(in millions)	
Cash provided by operating activities			
Net income	$ 328.0	$ 403.2	$ 249.5
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (Note 7)	269.3	223.4	165.6
Derivative fair value losses (gains) (Note 15)	15.2	(68.8)	64.2
Inventory market price adjustments (Note 6)	3.6	11.6	4.5
Gain (loss) on sale of net assets (Note 3)	(1.6)	—	(32.6)
Impairment charge (Note 3)	66.1	—	—
Other (Note 20)	12.1	25.5	1.8
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	(45.7)	56.1	(11.1)
Due from General Partner and affiliates (Note 12)	22.5	(13.3)	3.3
Accrued receivables	66.5	91.5	(82.3)
Inventory (Note 6)	(22.9)	46.0	2.0
Current and long-term other assets (Note 15)	(44.4)	10.2	(3.9)
Due to General Partner and affiliates (Note 12)	0.1	(3.6)	23.2
Accounts payable and other (Notes 5, 13 and 15)	(4.5)	(17.2)	(3.1)
Accrued purchases	47.5	(222.6)	73.5
Interest payable	11.3	13.1	9.5
Property and other taxes payable (Note 16)	6.0	10.3	0.2
Settlement of interest rate derivatives (Note 15)	(0.7)	(22.1)	(0.9)
Net cash provided by operating activities	728.4	543.3	463.4
Cash used in investing activities			
Additions to property, plant and equipment (Notes 7 and 12)	(1,292.1)	(1,375.4)	(1,980.2)
Changes in construction payables	(32.3)	(40.0)	83.6
Asset acquisitions, net of cash acquired (Note 3)	—	(11.7)	—
Proceeds from sale of net assets (Note 3)	150.8	—	133.0
Other (Notes 5 and 10)	—	(1.2)	(1.4)
Net cash used in investing activities	(1,173.6)	(1,428.3)	(1,765.0)
Cash provided by financing activities			
Net proceeds from unit issuances (Notes 11 and 12)	1.0	731.6	628.8
Distributions to partners (Notes 11 and 12)	(395.0)	(286.7)	(245.4)
Repayments of long-term debt (Note 10)	(420.7)	(56.0)	(31.0)
Repayment of affiliate notes payable (Note 12)	(130.0)	—	(136.2)
Net proceeds from issuances of long-term debt (Note 10)	—	1,286.7	592.8
Net borrowings (repayments) under Credit Facility (Note 10)	598.2	(233.2)	400.0
Net commercial paper repayments (Note 10)	—	(268.0)	(171.5)
Borrowings from General Partner and affiliates (Notes 10 and 12)	269.7	—	130.0
Contribution from noncontrolling interest (Note 12)	329.7	—	—
Other	(4.0)	—	—
Net cash provided by financing activities	248.9	1,174.4	1,167.5
Net increase (decrease) in cash and cash equivalents	(196.3)	289.4	(134.1)
Cash and cash equivalents at beginning of year	339.9	50.5	184.6
Cash and cash equivalents at end of period	$ 143.6	$ 339.9	$ 50.5

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

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2009	December 31, 2008
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 5)	$ 143.6	$ 339.9
Restricted cash (Notes 5 and 10)	—	0.1
Receivables, trade and other, net of allowance for doubtful accounts of $6.8 in 2009 and $2.6 in 2008	148.5	103.0
Due from General Partner and affiliates (Note 12)	18.0	40.5
Accrued receivables	440.4	507.3
Inventory (Note 6)	71.9	53.0
Other current assets (Note 15)	47.5	80.7
	869.9	1,124.5
Property, plant and equipment, net (Notes 7 and 12)	7,716.7	6,722.9
Goodwill (Note 8)	246.7	256.5
Intangibles, net (Note 9)	82.9	88.7
Other assets, net (Note 15)	72.1	108.3
	$ 8,988.3	$ 8,300.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 12)	$ 46.2	$ 42.2
Accounts payable and other (Notes 5, 13 and 15)	205.4	225.3
Accrued purchases	428.6	381.2
Interest payable	45.3	34.0
Property and other taxes payable (Note 16)	38.8	32.8
Loan from General Partner (Notes 10 and 12)	269.7	—
Current maturities of long-term debt (Note 10)	31.0	420.7
	1,065.0	1,136.2
Long-term debt (Note 10)	3,791.2	3,223.4
Notes payable to affiliate (Notes 10 and 12)	—	130.0
Other long-term liabilities (Notes 13, 15 and 16)	62.2	84.4
	4,918.4	4,574.0
Commitments and contingencies (Note 13)		
Partners' capital (Notes 11 and 12)		
Class A common units (97,443,352 and 76,088,834 at December 31, 2009 and 2008, respectively)	2,884.9	2,104.0
Class B common units (3,912,750 at December 31, 2009 and 2008)	78.6	85.0
Class C units (Zero and 19,688,968 at December 31, 2009 and 2008, respectively)	—	886.5
i-units (16,388,867 and 14,763,055 at December 31, 2009 and 2008, respectively)	588.8	553.8
General Partner	251.1	84.7
Accumulated other comprehensive income (loss) (Note 15)	(74.6)	12.9
Total Enbridge Energy Partners, L.P. partners' capital	3,728.8	3,726.9
Noncontrolling interest (Note 12)	341.1	—
Total partners' capital	4,069.9	3,726.9
	$ 8,988.3	$ 8,300.9

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,					
	2009		2008		2007	
	Units	Amount	Units	Amount	Units	Amount
	(in millions, except unit amounts)					
Class A common units:						
Beginning balance	76,088,834	$ 2,104.0	55,238,834	$ 1,340.7	49,938,834	$ 1,141.7
Net income allocation	—	177.9	—	217.0	—	130.1
Allocation of proceeds and issuance costs from unit issuance	21,245	1.3	20,850,000	774.1	5,300,000	264.9
Conversion of Class C units to Class A common units	21,333,273	924.2	—	—	—	—
Distributions	—	(322.5)	—	(227.8)	—	(196.0)
Ending balance	97,443,352	2,884.9	76,088,834	2,104.0	55,238,834	1,340.7
Class B common units:						
Beginning balance	3,912,750	85.0	3,912,750	72.9	3,912,750	67.6
Net income allocation	—	9.1	—	14.7	—	9.8
Allocation of proceeds and issuance costs from unit issuance	—	—	—	12.6	—	10.0
Distributions	—	(15.5)	—	(15.2)	—	(14.5)
Ending balance	3,912,750	78.6	3,912,750	85.0	3,912,750	72.9
Class C units:						
Beginning balance	19,688,968	886.5	18,073,367	874.1	11,070,152	509.8
Net income allocation	—	37.7	—	69.0	—	39.9
Allocation of proceeds and issuance costs from unit issuance	—	—	—	(56.6)	5,930,792	324.4
Conversion of Class C units to Class A common units	(21,333,273)	(924.2)	—	—	—	—
Cash payment for settlement of fractional Class C units	(2)	—	—	—	—	—
Distributions	1,644,307	—	1,615,601	—	1,072,423	—
Ending balance	—	—	19,688,968	886.5	18,073,367	874.1
i-units:						
Beginning balance	14,763,055	553.8	13,564,086	515.3	12,674,148	466.3
Net income allocation	—	35.0	—	51.8	—	32.0
Allocation of proceeds and issuance costs from unit issuance	—	—	—	(13.3)	—	17.0
Distributions	1,625,812	—	1,198,969	—	889,938	—
Ending balance	16,388,867	588.8	14,763,055	553.8	13,564,086	515.3
General Partner:						
Beginning balance		84.7		62.9		47.6
Net income allocation		56.9		50.7		37.7
General Partner contribution		166.5		14.8		12.5
Distributions		(57.0)		(43.7)		(34.9)
Ending balance		251.1		84.7		62.9
Accumulated other comprehensive loss:						
Beginning balance		12.9		(294.4)		(189.6)
Net realized losses (gains) on changes in fair value of derivative financial instruments reclassified to earnings		(37.6)		140.5		94.8
Unrealized net gain (loss) on derivative financial instruments		(49.9)		166.8		(199.6)
Ending balance		(74.6)		12.9		(294.4)
Total Enbridge Energy Partners, L.P. partners' capital at December 31,		3,728.8		3,726.9		2,571.5
Noncontrolling interest:						
Beginning balance		—		—		—
Capital contributions		329.7		—		—
Comprehensive income:						
Net income allocation		11.4		—		—
Ending balance		341.1		—		—
Total partners' capital at December 31,		$ 4,069.9		$ 3,726.9		$ 2,571.5

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. and 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, and 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 our general partner, Enbridge Energy Company, Inc., 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 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. In October 2009 all of our existing Class C units were converted on a one-for-one basis into Class A common units. At December 31, 2009 and 2008, our ownership was distributed as follows:

	2009	2008
Class A common units owned by the public	61.7%	51.2%
Class A common units owned by our General Partner	19.4%	13.9%
Class B common units owned by our General Partner	3.3%	3.4%
Class C units owned by our General Partner	—	5.5%
Class C units owned by institutional investors	—	11.3%
i-units owned by Enbridge Management[(1)]	13.6%	12.7%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

(1) Our general partner owns 17.2% 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, known as 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 project, which we refer to as the Alberta Clipper Project. All assets, liabilities and operations related to the Alberta Clipper Project are designated by the Series AC interests, while all other operations are captured by the Series LH interests. Our general partner holds a 66.67 percent interest in the Series AC limited partner interest, while we hold a 33.329 percent direct Series AC limited partner interest and a 0.001 percent indirect Series AC general partner interest. We hold a 99.999 percent direct Series LH limited partner interest and a 0.001 percent indirect Series LH general partner interest.

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 this investment.

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, 2009 and 2008, Enbridge and its consolidated subsidiaries owned an effective 27.0 percent interest in us through its ownership in Enbridge Management and our general partner.

Business Segments

We conduct our business through three 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, or 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 4,700 miles of pipe, has been in operation for nearly 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 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 480 miles of active crude oil pipelines, including the FERC-regulated Ozark pipeline and approximately 15.9 million barrels of storage capacity, which serve refineries in the U.S. 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. Our Natural Gas segment includes nine natural gas treating plants and 22 natural gas processing plants at December 31, 2009, 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 10,000 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.

In November 2009, we sold natural gas pipeline assets and related facilities including two FERC-regulated natural gas transmission pipeline systems, that were considered non-core to our central Natural Gas business, located in the Southeast and Gulf Coast regions of the United States.

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 and NGL 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.

We have presented the operating results of the natural gas pipeline assets we sold in November 2009 as "Discontinued operations" in our consolidated statements of income for the years ended December 31, 2009, 2008 and 2007.

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 and underlying accounting practices, and ratemaking agreements with customers.

Certain of our liquids operations 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 nonregulated entity. Also, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated 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" 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 or settled as cash 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 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 throughput 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 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 business 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. 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 business. 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 Note 15 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 and condensate 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 condensate.
- 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 and NGLs 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, 2009, 2008 and 2007. 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 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 present cash accounts that are restricted as to withdrawal or usage as "Restricted cash" on our consolidated statements of financial position.

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 liquids 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 expense as incurred, or used for capital projects and new construction, and capitalized to property, plant and equipment.

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 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 U.S. 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.

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 value 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. At the time we determine that an impairment has occurred, we will reduce the carrying value of goodwill to its fair value.

Intangibles, Net

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. 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.

Income Taxes

We are not a taxable entity for U.S. 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. The Texas tax is computed on our modified gross margin. The Michigan tax consists of two different taxes that are based on net income and modified gross receipts. We have determined these taxes to be income taxes as set forth in the authoritative accounting guidance.

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

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.

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 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 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.

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 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 credit default swap spread rates, which are updated quarterly. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and is also adjusted quarterly based on current default swap spread rates on our outstanding indebtedness. 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 and commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). 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. In accordance with the authoritative accounting guidance, we record all derivative financial instruments on 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 depends on the intended use and designation of each instrument. For our derivative financial instruments related to commodities that do not qualify for hedge accounting, the change in market value is recorded as a component of "Cost of natural gas" in the consolidated statements of income. For our derivative financial instruments related to interest rates that do not qualify for hedge accounting, the change in fair market value is recorded as a component of "Interest expense" in the consolidated statements of income.

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 the cash flow and fair value hedges can affect net income for each period. We use published market price information where available, or quotations from over-the-counter ("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 objectives, and the methods 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 or the fair value 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. We determine the change in fair market value of financial instruments designated and qualifying as fair value hedges each period, which we record in earnings. In addition, we calculate the change in the fair market value of the hedged item, which is also recorded in earnings. To the extent that the two valuations offset, the hedge is effective and net earnings is not affected.

Our earnings are also affected by use of the mark-to-market method of accounting as required under 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 balance sheet and through earnings (i.e., using the "mark-to-market" method) 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 due to 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 "Accounts payable and other" and "Other long-term liabilities" in our consolidated statements of financial position at their undiscounted amounts. 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 typically 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 to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, our intentions, or the estimated economic life of the asset. Useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to allow us to reasonably estimate potential settlement dates and methods.

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

We did not record any additional AROs for the years ended December 31, 2009 and 2008. We recorded accretion expense of $0.3 million, $0.1 million and $0.2 million, respectively, in our consolidated statements of income for the years ended December 31, 2009, 2008 and 2007 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, 2009 and 2008. Following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for each of the years ended December 31, 2009 and 2008:

	2009	2008
	(in millions)	
Balance at beginning of period	$ 3.0	$ 2.9
Disposals of natural gas assets[(1)]	(2.1)	—
Additions	0.4	—
Accretion expense	0.3	0.1
Balance at end of period	$ 1.6	$ 3.0

[(1)] In November 2009 we sold our non-core natural gas pipeline assets to an unrelated third party. In connection with the sale, we transferred $2.1 million of AROs associated with these operations.

Recent Accounting Pronouncements Not Yet Adopted

Fair Value Measurements and Disclosures

In January 2010, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update No. 2010-06—*Fair Value Measurements and Disclosures*, referred to as ASU No. 2010-06. ASU No. 2010-06 updates the current authoritative guidance pertaining to fair value measurements by enhancing existing disclosure requirements for both the valuation techniques and inputs used to determine fair value measurements.

The new disclosure requirements created by this ASU are as follows:

- An entity should disclose the amounts of significant transfers in and out of Level 1 and 2 fair value measurements;
- Discussion of the reasons for transfers between all levels within the fair value hierarchy; and
- Provide a reconciliation, on a gross basis, for those fair value measurements that use significant unobservable inputs (Level 3) and present separate information about the purchases, sales, issuances, and settlements within the reconciliation.

The enhanced disclosure requirements provided by ASU No. 2010-06 include the following:

- Fair value measurements should be disclosed for each class of assets and liabilities;
- The inputs and valuation techniques used to measure the fair value for both recurring and nonrecurring fair value measurements that fall into either Level 2 or Level 3 of the fair value hierarchy.

The new disclosures and clarifications of existing disclosures are effective for interim and annual reporting periods beginning after December 15, 2009, with the exception of the disclosures regarding the purchases, sales, issuances, and settlements within the reconciliation of Level 3 fair value measurements which are effective for fiscal years and interim periods beginning after December 15, 2010. We did not adopt the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material effect on our financial statements other than modifications to our existing fair value disclosures.

3. ACQUISITIONS AND DISPOSITIONS

The acquisitions and dispositions presented below include only transactions with unrelated third-parties. We also executed acquisitions and dispositions with related parties, which we discuss below 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.

2009 Disposition

Natural Gas Pipeline Disposition

In November 2009, we sold non-core natural gas pipeline assets located predominantly outside of Texas for cash totaling approximately $150.8 million, excluding any subsequent settlement for working capital as provided in the sale agreement. The natural gas pipeline assets we sold include primarily intrastate and interstate natural gas transmission systems and related facilities, which serve onshore and offshore markets in the southeastern United States and along the Gulf Coast. The natural gas pipeline assets include over 1,400 miles of pipeline with diameters ranging from 2 to 30 inches. The areas in which the natural gas pipeline assets operate are not strategic to the ongoing central operations of our core Natural Gas segment assets.

We have presented the operating results through October 31, 2009 of the natural gas pipeline assets we sold and additional costs we incurred related to the divestiture of these assets through December 31, 2009, as "Income from discontinued operations" in our consolidated statements of income. Also included in "Income from discontinued operations" for the year ended December 31, 2009 is a charge for $66.1 million we recorded as an impairment to reduce the carrying value of the assets to our estimate of the fair value of these assets, partially offset by a $1.6 million reduction to this amount we realized upon completion of the sale. The following table presents in millions of dollars a summary of the assets and liabilities of our disposed natural gas pipeline operations at the date of sale, excluding any intercompany accounts that we eliminate in consolidation.

Assets:	
Inventory	$ 0.5
Property, plant and equipment	150.8
Total assets	$ 151.3
Liabilities:	
Other long-term liabilities	$ 2.1
Total liabilities	$ 2.1

The following table presents the operating results of the discontinued operations of our natural gas pipeline assets that we derived from historical financial information and have segregated from our continuing operations in our consolidated statements of income:

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Operating revenue	$ 173.6	$ 367.9	$ 290.9
Operating expenses			
Cost of natural gas	143.3	325.0	251.3
Operating and administrative	19.1	22.1	25.5
Depreciation and amortization	11.6	13.5	13.7
	174.0	360.6	290.5
Operating income (loss)	(0.4)	7.3	0.4
Interest expense	—	—	1.2
Other income (expense)	(64.5)	1.0	—
Income (loss) from discontinued operations	$ (64.9)	$ 8.3	$ (0.8)

2008 Acquisitions

During 2008, we completed two separate acquisitions totaling $11.7 million, the fair value of which we allocated entirely to "Property, plant and equipment" in our consolidated statement of financial position. We included the results of operations for the assets acquired in our Natural Gas segment from the acquisition date.

2007 KPC Disposition

In November 2007, we sold our Kansas pipeline system, or KPC, with a net asset value of approximately $100.4 million, including $9.2 million of goodwill, to an unrelated party for $133 million in cash, subject to adjustments for working capital items. KPC is an interstate natural gas transmission system, which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline ranging in diameter from 4 to 12 inches, along with three compressor stations. The area in which KPC operates is not strategic to the ongoing central operations of our core Natural Gas segment assets. The operating results of the KPC system were not material to our consolidated operating results or those of our Natural Gas segment for the year ended December 31, 2007. We recognized a gain of $32.6 million on the sale of KPC, which is presented in income from discontinued operations.

4. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER UNIT

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. The formula for distributing available cash as set forth in our partnership agreement is as follows:

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.59	2%	98%
First Target Distribution	> $0.59 to $0.70	15%	85%
Second Target Distribution	> $0.70 to $0.99	25%	75%
Over Second Target Distribution	In excess of $0.99	50%	50%

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

	For the year ended December 31,		
	2009	2008	2007
	(in millions, except per unit amounts)		
Net income	$ 328.0	$ 403.2	$ 249.5
Less: Net income attributable to noncontrolling interest	11.4	—	—
Net income attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	316.6	403.2	249.5
Less: Net income (loss) from discontinued operations	(64.9)	8.3	31.8
Net income from continuing operations attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	381.5	394.9	217.7
Less distributions paid:			
Incentive distributions to our general partner	(50.4)	(42.4)	(32.5)
Distributed earnings allocated to our general partner (2%)	(9.5)	(8.1)	(6.8)
Total distributed earnings to our general partner	(59.9)	(50.5)	(39.3)
Total distributed earnings to our limited partners (98%)	(462.6)	(396.5)	(332.6)
Total distributed earnings	(522.5)	(447.0)	(371.9)
Overdistributed earnings	$ (141.0)	$ (52.1)	$ (154.2)
Weighted average limited partner units outstanding	116.4	97.1	86.3
Basic and diluted earnings per unit:			
Distributed earnings per limited partner unit[(1)]	$ 3.97	$ 4.08	$ 3.85
Overdistributed earnings per limited partner unit[(2)]	(1.19)	(0.53)	(1.75)
Net income from continuing operations attributable to our limited partner interests per limited partner unit	2.78	3.55	2.10
Net income (loss) from discontinued operations attributable to our limited partner interests per limited partner unit	(0.54)	0.09	0.36
Net income per limited partner unit (basic and diluted)	$ 2.24	$ 3.64	$ 2.46

(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 underdistributed 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 issued check payments that have not yet been presented to the financial institution of approximately $24.2 million at December 31, 2009 and $30.5 million at December 31, 2008 are included in "Accounts payable and other" on our consolidated statements of financial position.

In September 2008, following the bankruptcy filing by Lehman Brothers Holdings Inc., or Lehman, Lehman Brothers Bank, FSB, or Lehman BB, as discussed in Note 10, ceased to honor its funding commitment under the terms of our Second Amended and Restated Credit Agreement, which we refer to as our Credit Facility. Bank of America, N.A., as administrative agent to our Credit Facility, previously required us to provide cash collateral for a portion of the letters of credit outstanding under the terms of our Credit Facility that would have been obligations of Lehman BB. The amount of cash collateral we provided was $0.1 million at December 31, 2008. On March 31, 2009, we amended our Credit Facility to remove Lehman BB as a lender, which eliminated the cash collateral requirement imposed on us by Bank of America, N.A., as administrative agent. At December 31, 2009, no cash collateral was required and none of our cash and cash equivalents were restricted for use.

6. INVENTORY

Our inventory is comprised of the following:

	December 31, 2009	December 31, 2008
	(in millions)	
Materials and supplies	$ 3.6	$ 3.9
Crude oil inventory	4.1	7.1
Natural gas and NGL inventory	64.2	42.0
	$ 71.9	$ 53.0

The "Cost of natural gas" on our consolidated statements of income includes charges totaling $3.6 million, $11.6 million and $4.5 million for the years ended December 31, 2009, 2008 and 2007, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and natural gas liquids, or NGLs, to reflect market value.

7. PROPERTY, PLANT AND EQUIPMENT

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

	Depreciation Rates	December 31, 2009	December 31, 2008
		(in millions)	
Land	—	$ 29.8	$ 17.9
Rights-of-way	2.55% - 6.41%	438.7	437.1
Pipelines	2.38% - 6.70%	4,401.9	4,327.8
Pumping equipment, buildings and tanks	2.54% - 14.29%	1,115.9	995.4
Compressors, meters and other operating equipment	2.58% - 20.0%	1,337.8	639.3
Vehicles, office furniture and equipment	1.40% - 33.3%	164.8	153.0
Processing and treating plants	2.68% - 3.77%	325.7	343.1
Construction in progress	—	1,326.3	1,057.0
Total property, plant and equipment		9,140.9	7,970.6
Accumulated depreciation		(1,424.2)	(1,247.7)
Property, plant and equipment, net		$ 7,716.7	$ 6,722.9

8. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2009 and 2008 are as follows:

	Liquids	Natural Gas	Marketing	Corporate	Total
			(in millions)		
December 31, 2007 and 2008	$ —	$ 236.1	$ 20.4	$ —	$ 256.5
Goodwill related to the sale of assets	—	(9.8)	—	—	(9.8)
December 31, 2009	$ —	$ 226.3	$ 20.4	$ —	$ 246.7

In November 2009, we sold non-core natural gas pipeline assets to an unrelated third party. In connection with the sale, we disposed of $9.8 million of goodwill associated with these operations, which we had previously impaired.

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. At June 30, 2009 we completed our annual goodwill impairment test 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 was reduced by ten percent in our June 30, 2009 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 9% to 10%;
2) An annual growth rate for our Natural gas and Marketing businesses of approximately 3.0% to 4.0%;
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, 2009, 2008 and 2007. 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, 2009.

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, 2007	$ 98.3	$ 9.6	$ 107.9	$ (15.7)	$ (0.7)	$ (16.4)	$ 91.5
Additions	—	1.6	1.6	—	—	—	1.6
Amortization	—	—	—	(3.9)	(0.5)	(4.4)	(4.4)
December 31, 2008	98.3	11.2	109.5	(19.6)	(1.2)	(20.8)	88.7
Additions	—	0.2	0.2	—	—	—	0.2
Dispositions	(2.2)	—	(2.2)	0.6	—	0.6	(1.6)
Amortization	—	—	—	(3.9)	(0.5)	(4.4)	(4.4)
December 31, 2009	$ 96.1	$ 11.4	$ 107.5	$ (22.9)	$ (1.7)	$ (24.6)	$ 82.9

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 approximates 25 years. We obtained the natural gas supply opportunities in conjunction with the 2003 North Texas system acquisition and relate entirely to our Natural Gas segment. The value of the intangible asset was determined by a third party appraisal and it represents the fair value associated with growth opportunities present in the Barnett Shale producing zone. We are amortizing the natural gas supply opportunities over the weighted average estimated useful life of the underlying reserves at the time of the acquisition, which approximates 25 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 November 2009 sale of natural gas pipeline assets, we disposed of $1.6 million of intangibles associated with these operations, which we had previously impaired, primarily representing the value of customer contracts.

We estimate the aggregate amortization expense associated with our intangibles for each of the five succeeding years through December 31, 2014 to approximate $4.4 million per year.

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. Our indebtedness with related parties is discussed in Note 12—*Related Party Transactions*.

		December 31,			
		2009		2008	
	Maturity	Rate	Dollars	Rate	Dollars
		(dollars in millions)			
First Mortgage Notes	2011	9.15%	$ 62.0	9.15%	$ 93.0
Credit Facility	2013	0.54%	765.0	3.80%	166.8
Senior Notes	2012-2038	7.05%	2,595.8	6.75%	2,985.0
Junior Subordinated Notes	2067	8.05%	399.4	8.05%	399.3
			3,822.2		3,644.1
Current maturities and short-term debt			(31.0)		(420.7)
Long-term debt			$ 3,791.2		$ 3,223.4

First Mortgage Notes

The First Mortgage Notes, or the Notes, are collateralized by a first mortgage lien on substantially all of the property, plant and equipment of the OLP, and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. "Property, plant and equipment, net," associated with the OLP was $4,559.5 million and $3,456.2 million at December 31, 2009 and 2008, respectively. The Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. We do not believe these restrictions will negatively impact our ability to finance future expansion projects. Under the Notes agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash (see Note 11) for the immediately preceding calendar quarter. We would be required to pay a redemption premium pursuant to the Notes agreements should we elect to repay the Notes prior to their stated maturity.

Under the terms of the Notes, we are required to establish, at the end of each quarter, a debt service reserve. This reserve includes an amount equal to 50 percent of the prospective Notes interest payments for the immediately following quarter and an amount for Notes sinking fund repayments. At December 31, 2009 and 2008, there was no required debt service reserve, as we have made all required interest and sinking fund payments.

Credit Facility

On March 31, 2009, we amended our Credit Facility to remove Lehman BB as a lender due to the 2008 bankruptcy filing by its parent, Lehman, which effectively reduced the amounts available to us under our Credit Facility. The removal of Lehman BB permanently reduced both the amount we may borrow under the terms of our Credit Facility to $1,167.5 million as well as the number of committed lenders to 13. The amendment to our Credit Facility did not result in any changes to the pricing, fees or other commercial terms.

Our Credit Facility among other conditions includes the following terms: (1) a maximum principal amount of credit available to us at any one time of $1,167.5 million; (2) the right to request increases in the maximum principal amount of credit available at any one time from $1.167.5 million to approximately $1.4 billion; (3) no sublimit on letters of credit; and (4) a three-year facility that matures April 4, 2013 and grants us the option to request annual extensions of maturity and a one-year term out period upon maturity.

At December 31, 2009, we had $765.0 million outstanding under our Credit Facility at a weighted average interest rate of 0.54% and letters of credit totaling $14.9 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances, if any, and the balance of our letters of credit outstanding. At December 31, 2009, we could borrow $387.6 million under the terms of our Credit Facility, determined as follows:

	(in millions)
Total credit available under Credit Facility	$ 1,167.5
Less: Amounts outstanding under Credit Facility	765.0
Balance of letters of credit outstanding	14.9
Total amount we could borrow at December 31, 2009	$ 387.6

Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.25 to 1.0 for periods ending after March 31, 2009 through periods ending on or before March 31, 2010; and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. At December 31, 2009, our leverage ratio was approximately 3.43 as computed pursuant to the terms of 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.

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, which is typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the principal amount due. During the years ended December 31, 2009, 2008 and 2007, we net settled borrowings of approximately $3,092.1 million, $1,483.3 million and $180 million, respectively, on a non-cash basis.

Commercial Paper Program

We have an established commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We generally access the commercial paper market to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates we can obtain for commercial paper borrowings are more favorable than the interest rates we can obtain under our Credit Facility. At December 31, 2009 and 2008, we had no commercial paper outstanding.

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. We have granted the holders of our Senior Notes due 2019 an option to require us to repurchase all or a portion of the notes on March 1, 2012 at a purchase price of 100 percent of the principal amount of the notes tendered plus accrued and unpaid interest. The interest rates presented in this table represent the interest rates as set forth on the face of each note agreement without consideration to any discount or interest rate hedging activities.

	Interest Rate	December 31, 2009	December 31, 2008
		(in millions)	
Senior Notes due 2009	4.000%	$ —	$ 175.0
Senior Notes due 2012	7.900%	100.0	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 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, unsecured zero coupon notes due 2022	5.358%	—	214.7
		2,600.0	2,989.7
Unamortized Discount		(4.2)	(4.7)
		$ 2,595.8	$ 2,985.0

Zero Coupon Senior Notes

In August 2009, we repaid the holder of our senior, unsecured zero coupon notes due 2022 the full amount of the outstanding balance of approximately $222.3 million. The amount repaid includes $22.3 million of interest that we added to the original $200 million of principal of the zero coupon notes, including approximately $7.6 million of interest that we added during the year ended December 31, 2009. During the year ended December 31, 2008, we added $11.1 million of interest to the principal balance of the zero coupon notes.

Junior Subordinated Notes

The $400 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 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, from September 27, 2007 to October 1, 2017, payable semi-annually in arrears on April 1 and October 1 of each year beginning April 1, 2008. 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.

364-day Credit Facilities

In April 2009, we entered into two unsecured and non-guaranteed revolving credit facility agreements totaling $350 million for funding our general activities and working capital, which we refer to as the 364-day Credit Facilities. The 364-day Credit Facilities included a $200 million agreement with Barclays Bank PLC, as administrative agent, and Barclays Bank PLC and Export Development Canada as lenders. A separate $150 million affiliate credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge, was also a component of the 364-day Credit Facilities. In December 2009, we terminated the 364-day Credit Facilities in accordance with the credit facility agreements and without penalty.

Interest

For the years ended December 31, 2009, 2008, and 2007, our interest cost is comprised of the following:

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Interest expense	$ 228.6	$ 180.6	$ 99.8
Interest capitalized	30.6	41.0	47.4
Interest cost incurred	$ 259.2	$ 221.6	$ 147.2
Interest paid	$ 241.5	$ 193.1	$ 125.8

Maturities of Third Party Debt

The scheduled maturities of outstanding third party debt, excluding any discounts at December 31, 2009, are summarized as follows in millions:

2010	$ 31.0
2011	31.0
2012	600.0
2013	965.0
2014	200.0
Thereafter	2,000.0
Total	$ 3,827.0

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 Credit Facility borrowings approximate their fair values at December 31, 2009 and 2008 due to the short-term nature and frequent repricing of these obligations. 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,			
	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Credit Facility	$ 765.0	$ 765.0	$ 166.8	$ 166.8
9.150% First Mortgage Notes	62.0	69.9	93.0	93.8
5.358% Senior unsecured zero coupon notes due 2022	—	—	214.7	211.0
4.000% Senior Notes due 2009	—	—	175.0	175.2
7.900% Senior Notes due 2012	100.0	109.5	99.9	93.7
4.750% Senior Notes due 2013	199.9	201.2	199.9	163.4
5.350% Senior Notes due 2014	199.9	206.9	199.9	151.3
5.875% Senior Notes due 2016	299.8	315.0	299.8	234.5
7.000% Senior Notes due 2018	99.9	111.6	99.9	81.9
6.500% Senior Notes due 2018	398.2	433.2	398.0	317.7
9.875% Senior Notes due 2019	499.8	664.8	499.7	500.4
7.125% Senior Notes due 2028	99.9	110.9	99.8	72.7
5.950% Senior Notes due 2033	199.7	188.8	199.7	119.7
6.300% Senior Notes due 2034	99.8	98.0	99.8	62.3
7.500% Senior Notes due 2038	398.9	449.5	398.9	289.2
8.050% Junior subordinated notes due 2067	399.4	381.8	399.3	209.3
Total	$ 3,822.2	$ 4,106.1	$ 3,644.1	$ 2,942.9

11. PARTNERS' CAPITAL

Our capital accounts are comprised of a two percent general partner interest and 98 percent limited partner interests. Our limited partner interests at December 31, 2009 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 the our distributions, including certain incentive income distributions.

Class A common units

The following table presents the net proceeds from our Class A common unit issuances for each of the years ended December 31, 2009, 2008 and 2007. 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.

In October 2009, we issued and sold 21,245 Class A common units to our general partner to facilitate the conversion of our Class C units. We have included a discussion of the conversion in the section labeled "Class C units" following the table 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)			
2009					
October[3]	21,245	$ 47.070	$ 1.0	$ —	$ 1.0
2008					
December[3]	16,250,000	$ 30.760	$ 499.6	$ 10.2	$ 509.8
March	4,600,000	49.000	217.2	4.6	221.8
2008 Totals	20,850,000		$ 716.8	$ 14.8	$ 731.6
2007					
May	5,300,000	$ 58.000	$ 301.9	$ 6.1	$ 308.0

(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) All Class A common units from the issuance were issued to our General Partner.

Class B common units

Our outstanding Class B common units are held entirely 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.

Class C units

In October 2009, the Class C units converted into Class A common units, on a one-for-one basis, resulting in the issuance of 21,333,273 Class A common units and a cash payment of $123.21 for the 2.608092 remaining fractional units. We effected the conversion of our outstanding Class C units into Class A common units in accordance with the terms of our partnership agreement. The conversion was effective upon the determination by our general partner that the converted Class C units would have, as a substantive matter, like intrinsic economic and federal income tax characteristics, in all material respects, to the intrinsic economic and federal income tax characteristics of our outstanding Class A common units. Our general partner made this determination after adjustments were made to the capital accounts of our limited partners in connection with the issuance of 21, 245 Class A common units to our general partner.

The Class C units that we converted in October 2009 to Class A common units were issued and sold in two separate private transactions, the details of which are as set forth in the table below. The proceeds we received from the Class C unit issuances were used to partially reduce short-term borrowings from issuances of commercial paper and our Credit Facility that were used to finance a portion of our capital expansion program.

During the time our Class C units were outstanding, they had voting and other economic rights that were substantially similar to our Class A and Class B common units, except that the Class C units received quarterly distributions in-kind rather than in cash from the time they were issued through August 15, 2009. The funds we retained from distributions that we paid in-kind on the Class C units during 2006, 2007, 2008 and 2009, while contributing to the aggregate number of Class C units outstanding, were also used to finance a portion of our capital expansion program. Following the conversion of the Class C units to Class A common units and the payment for any fractional amounts, we no longer have any Class C units issued or outstanding.

Issuance Date	Number of Class C units Issued	Offering Price per Class C 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)			
2007					
April	5,930,792	$ 53.113	$ 314.4	$ 6.4	$ 320.8
2006					
August	10,869,565	$ 46.000	$ 500.0	$ 10.2	$ 510.2

(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.

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 U.S. 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.

Distributions

Our partnership agreement requires us to distribute 100 percent of our "Available Cash", which is generally defined in our partnership agreement as the sum of all cash receipts and net additions to reserves for future cash requirements less cash disbursements and amounts retained by us. 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. However, we also retain reserves to provide for the proper conduct of our business 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 98.0 percent to holders of our limited partner units and two percent 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 15.0 percent, 25.0 percent and 50.0 percent of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 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 business.

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 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 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.

Through August 15, 2009, in lieu of cash distributions, the holders of our Class C units received quarterly distributions of additional Class C units with a value equal to the quarterly cash distributions we paid to the holders of our Class A and Class B common units. The number of additional Class C units we issued was determined by dividing the quarterly cash distribution per unit we paid on our common units by the average market price of a Class A common unit as listed on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. As a result, the number of Class C units and the percentage of our total units owned by holders of the Class C units was increased automatically under the provisions of our partnership agreement. The cash equivalent amount of the additional Class C units was treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner. Following the October 2009 conversion of our Class C units into Class A common units, the in-kind distributions previously made to holders of the converted Class C units are now made in cash to them as holders of Class A common units.

The following table sets forth our distributions, as approved by Enbridge Management's board of directors for each period in the years ended December 31, 2009, 2008 and 2007.

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[1]	Amount of Distribution of Class C units to Class C unit Holders[2]	Retained from General Partner[3]	Distribution of Cash
		(in millions, except per unit amounts)						
2009								
October 29	November 5	November 13	$ 0.990	$ 131.3	$ 15.9	$ —	$ 0.3	$ 115.1
July 24	August 6	August 14	0.990	130.3	15.5	20.7	0.7	93.4
April 30	May 7	May 15	0.990	129.2	15.1	20.1	0.7	93.3
January 30	February 5	February 13	0.990	128.0	14.6	19.5	0.7	93.2
				$ 518.8	$ 61.1	$ 60.3	$ 2.4	$ 395.0
2008								
October 13	November 6	November 14	$ 0.990	$ 108.8	$ 14.3	$ 18.9	$ 0.7	$ 74.9
July 28	August 6	August 14	0.990	108.0	13.9	18.6	0.7	74.8
April 28	May 7	May 15	0.950	102.2	13.1	17.5	0.6	71.0
January 28	February 6	February 14	0.950	96.7	12.9	17.2	0.6	66.0
				$ 415.7	$ 54.2	$ 72.2	$ 2.6	$ 286.7
2007								
October 29	November 6	November 14	$ 0.950	$ 96.0	$ 12.7	$ 16.8	$ 0.6	$ 65.9
July 27	August 6	August 14	0.925	92.6	12.1	16.2	0.6	63.7
April 26	May 7	May 15	0.925	86.6	11.9	15.9	0.6	58.2
January 26	February 6	February 14	0.925	80.0	11.7	10.2	0.5	57.6
				$ 355.2	$ 48.4	$ 59.1	$ 2.3	$ 245.4

(1) We issued 1,625,812, 1,198,969 and 889,938 i-units to Enbridge Management, the sole owner of our i-units, during 2009, 2008 and 2007, respectively, in lieu of cash distributions.

(2) We issued 1,644,307, 1,615,601 and 1,072,423 additional Class C units to our Class C unitholders in lieu of cash distributions during 2009, 2008 and 2007 including 538,609, 529,207 and 385,032 to our general partner, respectively.

(3) We retained an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner to maintain its 2 percent 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 EPI, 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, 2009, 2008 and 2007 were \$63.4 million, \$62.3 million and \$49.0 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 of 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 and charges us with the costs that are specific to us.

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, 2009, 2008 and 2007 were \$225.8 million, \$207.5 million and \$181.6 million, respectively.

Enbridge and its affiliates allocated direct workforce costs to us for our construction projects of \$10.0 million, \$13.2 million and \$18.1 million during 2009, 2008 and 2007, respectively, that we recorded as additions to "Property, plant and equipment, net" on our consolidated statements of financial position.

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 twelve months ending December 31, 2009, 2008 and 2007, are operating revenues of \$181.3 million, \$267.0 million, and \$95.2 million, respectively, related to these transactions.

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 2009, 2008 and 2007 was approximately $0.8 million, $0.7 million and $0.6 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 twelve months ending December 31, 2009, 2008 and 2007, are costs for natural gas purchases of $53.6 million, $99.3 million and $6.2 million, respectively, related to these purchases.

Financing Transactions with Affiliates

EUS Credit Facility

In April 2009, we entered into a $150 million unsecured and non-guaranteed revolving credit facility agreement with Enbridge (U.S.) Inc., which we terminated in December 2009 as discussed in Note 10—Debt—*364-day Credit Facilities.* In connection with our termination of the Enbridge (U.S.) Inc. portion of the 364-day Credit Facilities, we recognized $1.5 million of debt origination fees on our consolidated statement of income for the year ended December 31, 2009.

Hungary Note Payable

In November 2009, we repaid the $130.0 million outstanding balance of our notes payable to Enbridge Hungary Ltd., an affiliate of our general partner (the "Hungary Note"). At December 31, 2009 we had no amounts outstanding under the Hungary Note, while at December 31, 2008 there was $130 million outstanding. We paid interest at a fixed rate of 8.4% per annum on the Hungary Note semi-annually in June and December of each year through November 2009 when we repaid the outstanding balance and accrued interest due. For the years ended December 31, 2009 and 2008, we made interest payments of approximately $9.3 million and $10.9 million, respectively.

EUS Credit Agreement

In December 2007, we entered into an unsecured revolving credit agreement (the "EUS Credit Agreement") with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Credit Facility as discussed in Note 10—Debt. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Credit Facility. At December 31, 2009 and 2008, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use. The EUS Credit Agreement is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes.

Joint Funding Arrangement for Alberta Clipper Project

In July 2009, we entered into a joint funding arrangement to finance construction of the U.S. segment of the Alberta Clipper Project, with several of our affiliates and affiliates of Enbridge. This joint funding arrangement is pursuant to a Contribution Agreement by and among our general partner, Enbridge Pipelines (Alberta Clipper) L.L.C., Enbridge Energy, Limited Partnership, Enbridge Energy Partners, L.P., Enbridge Pipelines (Lakehead) L.L.C., and Enbridge Pipelines (Wisconsin) Inc. Under the terms of the Contribution Agreement, the parties have agreed to jointly fund, construct and operate the Alberta Clipper Project. To effect the provisions of the Contribution Agreement, the limited partnership agreement for the OLP, was amended and restated to establish two distinct series of partnership interests. All the assets, liabilities and operations related to the Alberta Clipper Project are designated specifically by the Series AC interests while all other assets and operations of the OLP are designated by the Series LH interests. Liabilities of the OLP have recourse to both the Series AC and Series LH assets. In exchange for a 66.67 percent ownership interest in the Series AC interests, Enbridge, through our general partner, is funding approximately two-thirds of both the debt financing and equity requirement for the Alberta Clipper Project in return for approximately two-thirds of the Alberta Clipper Project's earnings and cash flows. The 66.67 percent ownership interest of our general partner in the Series AC interests and the earnings and cashflows attributable to this interest are presented as the balance and activities of the noncontrolling interest in our consolidated financial statements. For our 33.33 percent ownership of the Series AC interests we are funding approximately one-third of the debt financing and required equity of the Alberta Clipper Project, for which we are entitled to approximately one-third of the project's earnings and cash flows. We and our general partner each have a right of first refusal on the other's investment in the Alberta Clipper Project, and we retain the right to fund up to 100 percent of any expansion of the Alberta Clipper Project, which would result in a corresponding adjustment of our general partner's interest.

The funding of the construction costs for the Alberta Clipper Project provided by our general partner are facilitated through a newly established credit facility with us, which we refer to as the A1 Credit Agreement, as well as capital contributions directly by the Series AC holders. The A1 Credit Agreement will be used to fund Enbridge's debt portion of project costs during construction. The A1 Credit Agreement is an unsecured, non-revolving credit facility with a capacity of $400 million and will be utilized for the purpose of funding capital expenditures that are directly related to the Alberta Clipper Project and to refinance the existing indebtedness previously incurred to fund such costs.

Under the A1 Credit Agreement, project expenditures are funded through either a Base Rate Loan or Fixed Period Eurodollar Rate Loan as those terms are defined in the A1 Credit Agreement. Funds drawn under the Base Rate Loan bear interest at a base rate that is equal to the greater of (a) the Federal Funds Rate plus one half of one percent or (b) the "Prime rate" as determined by Bank of America, N.A., from time to time. Funds drawn under Fixed Period Eurodollar Rate Loans will bear interest at a rate per annum equal to the BBA LIBOR plus an additional rate per annum based on the credit rating of our senior unsecured long-term debt as determined by Standard & Poor's Financial Services LLC and Moody's Investors Service, which we respectively refer to as S&P and Moody's. Any interest incurred and outstanding is due on the last business day of March, June, September and December and the maturity date for both the Based Rate and Fixed Period Eurodollar Rate loans.

The A1 Credit Agreement contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.25 to 1.0 for periods ending on or before March 31, 2010 and a maximum ratio of 5.0 to 1.0 for periods ending June 30, 2010 and thereafter. At December 31, 2009, our leverage ratio was approximately 3.43 as computed pursuant to the terms of the A1 Credit Agreement. The A1 Credit Agreement also places limitations on the debt that our subsidiaries may incur directly. Accordingly, we are expected to provide debt financing to our subsidiaries as necessary.

The maturity date of the A1 Credit Agreement is the earlier of July 1, 2011 or the date that is 180 days following the in-service date of the U.S. portion of the Alberta Clipper crude oil pipeline. At points of time either shortly before or shortly after the in-service date for the Alberta Clipper Project, we must use commercially reasonable efforts to issue debt in one or more capital market transactions, the proceeds of which will be used to refinance the loans we make to the OLP on substantially the same terms as the debt issued in the capital market transactions. On the same date, our general partner will refinance its loans with respect to the project on substantially the same terms as we refinanced our loan to the OLP. Repayment of any principal amount outstanding on the A1 Credit Agreement is required on the maturity date. The A1 Credit Agreement allows for the prepayment of borrowings prior to the scheduled maturity date without penalty. The A1 Credit Agreement is limited in recourse only to the Series AC assets. At December 31, 2009, we had $269.7 million outstanding under the A1 Credit Agreement bearing interest at a weighted average rate of 0.548% per annum. Our general partner also made equity contributions totaling $329.7 million to the OLP for the year ended December 31, 2009, to fund its equity portion of the construction costs associated with the Alberta Clipper Project. In addition, we allocated $11.4 million of earnings to our general partner for its 66.67 percent of the earnings of the Alberta Clipper Project derived from the allowance for equity during construction, which is presented in our consolidated statements of income as "Net income attributable to noncontrolling interest."

Asset Purchase and Sale Transactions with Affiliates

Purchase of Line Pipe

We, our general partner and Enbridge Pipelines regularly collaborate on construction projects that are mutually beneficial to our respective customers and operations. Examples of such projects include the Southern Access and Alberta Clipper crude oil pipeline projects where we have constructed and are constructing the U.S. portion of the projects and Enbridge Pipelines has constructed and is constructing the Canadian portion. In September 2008, we acquired for $21.1 million, approximately 22 miles of 36 inch diameter line pipe from our general partner. Also, in March 2009, we acquired, for $27.0 million, approximately 25 miles of 36-inch diameter line pipe from our general partner. Both purchases were for our use in constructing the Alberta Clipper crude oil pipeline project, referred to as the Alberta Clipper Project. The line pipe was initially obtained by our general partner for use in constructing the Southern Access extension, which has been delayed due to a protracted regulatory process. The transactions were previously approved by the Enbridge Management Board of Directors.

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 Project, we agreed to lease Line 13 from Southern Lights for monthly payments of $1.8 million. The transfer and lease became effective February 20, 2009, which was the in-service date for the light sour pipeline. The lease of Line 13 will be effective until the earliest of (i) July 1, 2010, (ii) upon the transfer of the Canadian portion of Line 13 from Enbridge Pipelines to Enbridge Southern Lights LP, a wholly-owned subsidiary of Enbridge Pipelines or (iii) early termination of the lease. We are able to terminate the lease at any time during the term by providing Southern Lights with written notice, at which time we would be required to return Line 13 to Southern Lights. The costs associated with the lease are being recovered through a tolling surcharge on our Lakehead system and the net effect on our cash flow over the life of the transaction is expected to approximate zero. The exchange resulted in a $166.5 million increase in "Property, plant and equipment" 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. Subsequent to the initial exchange, an additional $5.8 million of costs were incurred by Southern Lights through December 31, 2009 that have been transferred to us through the capital account of our general partner, which are included in the $171.5 million cost presented above. 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.

Spearhead Pipeline Acquisition

In May 2009, we purchased a portion of a crude oil pipeline system from CCPS Transportation, L.L.C., a wholly-owned subsidiary of our general partner, for approximately $75 million, representing the carrying value in the records of our general partner. The portion of the system, which we refer to as Spearhead North, includes approximately seven storage tanks and 75 miles of pipeline that our general partner reversed to provide northbound service from Flanagan, Illinois to Griffith, Indiana. The acquisition of Spearhead North complements the existing operations of our Lakehead system, as our newly-constructed Southern Access pipeline ends in Flanagan where it connects to Spearhead North. The transaction was previously approved by the Enbridge Management Board of Directors.

UTOS Disposition

In January 2009, we sold the member interests of our UTOS system for minimal consideration to Enbridge Offshore (Gas Transportation), L.L.C., a wholly-owned subsidiary of Enbridge. The UTOS system transports natural gas from offshore platforms on a fee for service basis to other pipelines onshore for further delivery and does not have long-term contracts. The UTOS system was not considered strategic to our ongoing central operations, but is strategically aligned with Enbridge's offshore operations.

General Partner Equity Transactions

Our general partner owns an effective two percent general partner interest in us. Pursuant to our partnership agreement we paid cash distributions to our general partner of $57.0 million, $43.7 million and $34.9 million for the years ended December 31, 2009, 2008 and 2007, respectively. The cash distributions we make to our general partner exclude an amount equal to two percent of the i-units and until the conversion to Class A common units, Class C unit distributions, which we retain from the General Partner to maintain its two percent general partner interest in us.

As of December 31, 2009, our general partner owned 23,259,168 Class A common units, representing a 19.4% limited partner interest in us. 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 federal income tax characteristics, in all material respects, to the intrinsic economic and federal income tax characteristics of our outstanding Class A common units. Along with the conversion, we issued and sold 21,245 Class A common units to our general partner for a purchase price of $47.07 per unit, or approximately $1.0 million.

As of December 31, 2009 and 2008, our general partner also owned 3,912,750 Class B common units, representing a 3.3 percent and 3.4 percent limited partner interest in us for the respective years. We paid the General Partner cash distributions of $15.5 million, $15.2 million and $14.5 million for the years ended December 31, 2009, 2008 and 2007, 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, 2009. At December 31, 2008 and 2007, our general partner owned 6,449,315 and 5,920,108 of our Class C units. We distributed 538,609, 529,207 and 385,032 additional Class C units to our general partner during the years ended December 31, 2009, 2008 and 2007, respectively, in lieu of making cash distributions. The Class C units owned by our general partner at December 31, 2008 and 2007 represented an approximately 5.5 percent and 6.4 percent limited partner interest in us. Refer to Note 11 for additional information regarding the Class C units.

In December 2008, we issued and sold 16.25 million Class A common units to the General Partner in a private placement for a purchase price of $30.76 per unit, or approximately $500 million. The Class A common units represent limited partner ownership interests in the Partnership. The December 2008 issuance increased the General Partner's ownership in the Partnership from approximately 15 percent to approximately 27 percent. The General Partner also contributed approximately $10.2 million to us to maintain its two percent general partner interest.

The following table presents our issuances of limited partner interests where our general partner made a contribution to retain its two percent general partner interest.

Issuance Date	Class of Limited Partnership Interest	Number of units Issued	Offering Price per unit	Net Proceeds to the Partnership[1]	General Partner Contribution	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amounts)				
October 2009	Class A	21,245	$ 47.070	$ 1.0	$ —	$ 1.0
December 2008	Class A	16,250,000	30.760	499.6	10.2	509.8
March 2008	Class A	4,600,000	49.000	217.2	4.6	221.8
May 2007	Class A	5,300,000	58.000	301.9	6.1	308.0
April 2007	Class C	5,930,792	53.113	314.4	6.4	320.8

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

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 could, at times, be 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 associated with the Lakehead system assets through insurance, 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 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, and to date, no material environmental risks have been identified.

In November 2007, an unexpected release and fire on line 3 of our Lakehead system occurred during planned maintenance near our Clearbrook, Minnesota terminal. We immediately shut down all pipelines in the vicinity and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline at an economic cost of $4.2 million as of December 31, 2009. The volume of oil released was approximately 325 barrels, which was largely contained in the trench that had been excavated to facilitate the planned maintenance. We completed excavation and repairs and returned the line to service within five days of the incident. In October of 2008, we received a letter from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") alleging violations of federal pipeline safety regulations and proposing a $2.4 million fine related to the release and fire. A provision for the amount of the fine has been made in "Accounts payable and other." We have the potential of incurring additional costs in connection with this incident, including expenditures necessary to remediate any operating condition that is determined to have caused this incident.

As of December 31, 2009 and 2008, we have recorded $7.3 million and $5.5 million, respectively, in "Accounts payable and other" and $3.4 million and $2.8 million in "Other long-term liabilities," respectively, 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.

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 24 million to 47 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 36 percent of the natural gas volumes on our natural gas assets are transported for customers on a contractual basis. We purchase the remaining 64 percent 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 material to us.

Right-of-Way

As part of our pipeline construction process, we must obtain certain right-of-way agreements from landowners whose property the pipeline will cross. Right-of-way agreements that we buy are capitalized as part of "Property, plant and equipment" in our consolidated statements of financial position. Right-of-way agreements that are leased from a third-party are expensed. We have recorded expenses of $2.4 million, $2.0 million and $1.6 million for the leased right-of-way agreements for the years ended December 31, 2009, 2008, and 2007, respectively.

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. We believe that the outcome of these legal and regulatory proceedings and related actions will not, individually or in the aggregate, have a material adverse effect on our operating results, cash flows or financial position.

Future Minimum Commitments

As of December 31, 2009, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

	2010	2011	2012	2013	2014	Thereafter	Total
				(in millions)			
Purchase commitments[(1)]	$ 248.7	$ —	$ —	$ —	$ —	$ —	$ 248.7
Power commitments[(2)]	3.5	0.8	0.7	—	—	—	5.0
Operating leases	14.6	14.8	12.0	9.5	9.4	52.8	113.1
Right-of-way[(3)]	2.0	2.0	2.0	1.9	1.9	46.9	56.7
Product purchase obligations[(4)]	23.5	24.5	24.7	16.2	0.9	0.1	89.9
Service contract obligations[(5)]	26.8	21.8	13.2	2.3	—	—	64.1
Total	$ 319.1	$ 63.9	$ 52.6	$ 29.9	$ 12.2	$ 99.8	$ 577.5

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our expansion 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 $2.0 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 2014.

(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.

The purchases made under our non-cancelable commitments for the years ended December 31, 2009, 2008 and 2007 were $345.1 million, $389.9 million and $483.8 million, respectively.

14. JOINT TARIFF REVENUES

Our subsidiary, Enbridge Energy, Limited Partnership, which we also refer to as the OLP, was party to a joint tariff agreement with Mustang Pipe Line, LLC, or Mustang, which owns a 100,000 barrel per day, or Bpd, crude oil pipeline that connects with our Lakehead system at Lockport, Illinois and transports crude oil to the Patoka, Illinois area. Mustang is 70% owned by a major integrated oil company that also serves as the operator and is 30% owned by Enbridge. The Mustang joint tariff arrangement is an unusual structure within our liquids pipeline system, since we have no other arrangements where neither we nor Enbridge are the billing carrier or operator of the pipeline with which we have a joint tariff arrangement.

Our joint tariff agreement with Mustang that was in place from October 2005 through March 2009 allowed for shippers on our Lakehead system to reach markets downstream of Chicago, Illinois at a discounted transportation rate for their commitments to transport crude oil on our system and then on the Mustang pipeline. Since October 2005, we incorrectly invoiced a shipper on our Lakehead system, which was not a committed shipper, at the discounted transportation rate. Additionally, we continued to invoice two other shippers whose commitments expired in September 2008 at discounted transportation rates rather than the undiscounted non-committed shipper rates. Due to our incorrectly invoicing these shippers, we understated approximately $13.5 million of operating revenues on our Lakehead system from October 2005 through December 2008. We invoiced and collected the previously unbilled amounts from these shippers in the first quarter of 2009.

In connection with the invoicing errors noted above, we also identified volumetric differences totaling approximately 11 million barrels of crude oil for the volumes we measured as delivered to the Mustang pipeline system at for five committed shippers and the volumes that Mustang reported as delivered at Patoka for the same committed shippers. The volumetric differences we identified primarily relate to our fiscal years ended December 31, 2007 and 2008, where we have determined that services provided by our Lakehead system to transport approximately 9.4 million barrels of crude oil were not invoiced. In December 2009, we invoiced an aggregate of $9.0 million for the 9.4 million barrels of crude oil we transported and had not previously invoiced, which we recognized as revenue in our consolidated statement of income for the year ended December 31, 2009.

Subject to our routine estimates surrounding the realizability of amounts billed, we have included the aggregate amount of $22.5 million, representing the $13.5 million and $9.0 million amounts discussed above, as revenue in our consolidated statement of income for the year ended December 31, 2009, following our determination that the previously unbilled 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 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 variable rate debt obligations are issued. 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 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. We have hedged a portion of our exposure to variability in future cash flows associated with natural gas and NGL sales and purchases and changes in interest rates on our variable rate debt through 2014 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, which we 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 use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

In accordance with the 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 "Cost of natural gas" 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. 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.

If a derivative financial instrument is designated and qualifies as a hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings and is adjusted by the gain or loss resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge's change in fair market value is recorded in earnings as the amount that is not offset by the gain or loss on the change in fair market value of the underlying asset or liability. Although we do not presently hold any derivative financial instruments designated as fair value hedges, in the past we have designated derivatives as fair value hedges of fixed rate debt in periods of high interest rates to achieve effectively lower variable rates. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in "Interest expense" on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, to qualify as a fair value hedge 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-qualified." These non-qualified 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" 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 gas from storage in a future period.

We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

- **Natural Gas Collars**—In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options and, pursuant to the authoritative accounting guidance, do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.
- **Optional Natural Gas Processing Volumes**—In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural gas contracts allow us the option of processing natural gas when it is economical and ceasing to do 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 purchases of natural gas required for processing. We will typically designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **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. Prior to April 1, 2009, forward contracts were not treated as derivative financial instruments pursuant to the normal purchase normal sale, or NPNS, exception allowed under authoritative accounting guidance, since the forward contracts resulted in physical receipt or delivery of NGLs. However, evolving markets for NGLs have increased opportunities for a portion of our forward contracts to be settled net rather than physically receiving or delivering the NGLs. Accordingly, we have revoked the NPNS exception on certain forward contracts associated with the liquids marketing operations of Dufour Petroleum, L.P., our wholly-owned subsidiary, executed after April 1, 2009. 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 will be subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.

Interest Rate Risk Exposures:

- **Interest Rate Caps**—At the corporate level, our earnings and cash flows are affected by fluctuations in interest rates associated with our variable interest rate debt. Our variable interest rate borrowing cost is determined at the time of each borrowing or interest rate reset based upon a posted LIBOR for the period of borrowing or interest rate reset, increased by a defined credit spread. In order to mitigate the negative effect that increasing interest rates can have on our cash flows, we have entered into interest rate caps, which establish a ceiling averaging approximately 1.12% on the interest rates we pay on up to $400 million of our variable rate indebtedness. Although our interest rate caps protect us from the adverse effect of higher interest rates, they do not qualify for hedge accounting and, as a result, changes in the market value of these instruments will create additional volatility in our earnings.

In all instances related to the commodity price exposures described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we employ for the derivative financial instruments we use 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 historical cost) 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.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of "Cost of natural gas" and "Interest expense" in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

	For the year ended December 31,		
	2009	2008	2007
	(in millions)		
Natural Gas segment			
Hedge ineffectiveness	$ (0.7)	$ (0.1)	$ —
Non-qualified hedges	(35.7)	85.1	(59.0)
Marketing			
Non-qualified hedges	20.7	(16.2)	(3.8)
Commodity derivative fair value gains (losses)	(15.7)	68.8	(62.8)
Corporate			
Non-qualified interest rate hedges	0.5	—	(1.4)
Derivative fair value gains (losses)	$ (15.2)	$ 68.8	$ (64.2)

Derivative Positions

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

	December 31,	
	2009	2008
	(in millions)	
Other current assets	$ 14.8	$ 70.6
Other assets, net	43.7	75.7
Accounts payable and other	(59.2)	(40.6)
Other long-term liabilities	(50.5)	(71.0)
	$ (51.2)	$ 34.7

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 that were in gain positions 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 and NGL sales and purchase agreements.

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 $1.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the years ended December 31, 2008 and 2007, we reclassified from AOCI to "Cost of natural gas" on our consolidated statements of income unrealized net losses of $140.5 million and $94.8 million, respectively. We estimate that approximately $31.3 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at December 31, 2009, will be reclassified from AOCI to earnings during the next twelve months.

As of December 31, 2009, we have provided letters of credit totaling $13.1 million in lieu of providing cash collateral to our counterparties pursuant to the terms of our International Securities Dealers Association ("ISDA®") agreements.

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

	December 31,	
	2009	2008
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	14.2	(39.6)
A	(63.1)	73.3
Lower than A	(3.2)	(1.2)
	(52.1)	32.5
Credit valuation adjustment	0.9	2.2
Total	$ (51.2)	$ 34.7

* As determined by nationally recognized statistical ratings organizations.

As the net receivable of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also declined. When credit thresholds are met pursuant to the terms of our ISDA® financial contracts, we have the right to require collateral from our counterparties. We have included any cash collateral received in the balances listed above. 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 or require immediate settlement of 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 each counterparty's credit rating. 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, but the agreements do not contain additional triggers or automatic termination clauses relating to credit downgrades. 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 the tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

At December 31, 2009, we were in an overall net liability position of $51.2 million, which included assets of $58.5 million. Based on our forward positions at December 31, 2009, if our credit ratings were downgraded to BBB-by Standard & Poor's or Baa3 by Moody's Investors Service, we would be required to provide $39.0 million in the form of either cash collateral or letters of credit to satisfy the requirements of our ISDA® agreements.

Counterparties to our derivative financial instruments include credit concentrations with U.S. financial institutions, international financial institutions, investment banking entities and, to a lesser extent, international integrated oil companies. At December 31, 2009, approximately $18.8 million of payables were due to U.S. financial institutions from us, including investment banks. We are in net liability positions of $30.2 million and $3.4 million with non-U.S. financial institutions and small non-integrated energy companies, respectively, representing amounts payable by us. We also have approximately $1.2 million of receivables that are payable to us from integrated oil companies. We are holding no cash collateral on our asset exposures and we have provided letters of credit totaling $13.1 million relating to our liability exposure pursuant to the margin thresholds in effect at December 31, 2009 under our ISDA® agreements.

Gross derivative balances are presented below without the effects of collateral received or posted and without the effects of master netting arrangements. Our assets are adjusted for the non-performance risk of our counterparties using their credit default swap spread rates. Likewise, in the case of our liabilities, our nonperformance risk is considered in the valuation, and is also adjusted based on current credit default swap spread rates on our outstanding indebtedness. 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 these schedules presented at gross values rather than the net amounts we present in our other derivative schedules, is also provided below.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	December 31, 2009			
	Asset Derivatives		Liability Derivatives	
	Financial Position Location	Fair Value	Financial Position Location	Fair Value
		(in millions)		
Derivatives designated as hedging instruments				
Interest rate contracts	Other current assets	$ —	Accounts payable and other	$ (7.0)
Interest rate contracts	Other assets, net	38.7	Other long-term liabilities	(18.9)
Commodity contracts	Other current assets	15.7	Accounts payable and other	(47.3)
Commodity contracts	Other assets, net	17.8	Other long-term liabilities	(50.9)
		72.2		(124.1)
Derivatives not designated as hedging instruments				
Interest rate contracts	Other current assets	5.8	Accounts payable and other	(4.8)
Interest rate contracts	Other assets, net	5.6	Other long-term liabilities	(4.4)
Commodity contracts	Other current assets	22.0	Accounts payable and other	(28.8)
Commodity contracts	Other assets, net	12.1	Other long-term liabilities	(6.8)
		45.5		(44.8)
Total derivative instruments		$ 117.7		$ (168.9)

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

	For the year ended December 31, 2009				
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)			
Interest rate contracts	$ 12.9	Interest expense	$ (2.3)	Interest expense	$ —
Commodity contracts	(102.0)	Cost of natural gas	39.9	Cost of natural gas	(0.7)
Total	$ (89.1)		$ 37.6		$ (0.7)

(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.

The amount of loss recognized in earnings represents $0.7 million related to the ineffective portion of the hedging relationships.

Effect of Derivative Instruments on Consolidated Statements of Income

		For the year ended December 31, 2009
Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	Amount of Gain or (Loss) Recognized in Earnings[1]
		(in millions)
Interest rate contracts	Interest expense	$ 0.5
Commodity contracts	Cost of natural gas	(15.0)
Total		$ (14.5)

(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, 2009		
	Assets	Liabilities	Total
		(in millions)	
Fair value of derivatives—gross presentation	$ 117.7	$ (168.9)	$ (51.2)
Effects of netting agreements	(59.2)	59.2	—
Fair value of derivatives—net presentation	$ 58.5	$ (109.7)	$ (51.2)

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, 2009 and 2008. 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. We have reclassified the fair value of derivative financial instruments that we value using pricing inputs derived from observable data to Level 2 in the following table after determining the pricing inputs used to value these financial instruments are not directly observable from prices quoted by an exchange.

	December 31,							
	2009				2008			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Assets:								
Derivative instruments, net	$ —	$ 55.7	$ 62.1	$ 117.8	$ —	$ 20.4	$ 119.6	$ 140.0
Liabilities								
Derivative instruments, net	—	(105.2)	(63.8)	(169.0)	—	(77.5)	(27.8)	(105.3)
Total	$ —	$ (49.5)	$ (1.7)	$ (51.2)	$ —	$ (57.1)	$ 91.8	$ 34.7

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities from January 1, 2009 to December 31, 2009 and from January 1, 2008 to December 31, 2008, for the respective periods. Interest rate swaps totaling $1.8 million were reclassified to Level 2 following our evaluation of the inputs used to compute fair value for these financial instruments and determination that the valuation inputs are more closely correlated with those that meet the qualifications for Level 2 classification as the values are derived from observable inputs, but are not directly observable.

	December 31,	
	2009	2008
	(in millions)	
Beginning balance as of January 1	$ 91.8	$ (167.7)
Realized and unrealized net losses	(85.5)	260.9
New transactions	(6.2)	(1.4)
Transfer out of Level 3	(1.8)	—
Balance as of December 31	$ (1.7)	$ 91.8
Change in unrealized net gains (losses) relating to instruments still held at December 31:	$ (102.3)	$ 149.7

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at December 31, 2009 and 2008.

	At December 31, 2009						At December 31, 2008	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	5,875,411	$ 5.63	$ 5.88	$ 1.6	$ (3.1)	$ 2.5	$ (6.5)
	NGL	120,000	73.80	45.30	3.4	—	—	(1.3)
Receive fixed/pay variable	Natural Gas	10,809,500	4.52	5.74	2.9	(16.0)	2.2	(27.5)
	NGL	3,312,010	40.39	49.36	9.7	(39.4)	28.0	—
	Crude Oil	720,790	71.95	82.30	3.1	(10.6)	5.5	(0.5)
Receive variable/pay variable	Natural Gas	86,551,709	5.62	5.51	13.0	(3.5)	0.8	(3.1)
Physical Contracts								
Receive fixed/pay variable	NGL	443,955	52.44	61.02	—	(4.0)	—	—
	Crude Oil	250,666	73.50	79.83	—	(1.6)	—	—
Receive variable/pay fixed	NGL	65,000	74.41	70.66	0.3	—	—	—
	Crude Oil	248,666	79.58	72.37	1.8	—	—	—
Receive variable/pay variable	Crude Oil	145,262	76.88	76.93	0.1	(0.1)	—	—
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	878,475	$ 6.21	$ 9.78	$ —	$ (3.1)	$ 2.6	$ (3.4)
	NGL	120,000	74.90	47.67	3.2	—	—	—
Receive fixed/pay variable	Natural Gas	8,426,000	3.98	6.31	—	(19.3)	1.1	(28.1)
	NGL	1,232,240	58.32	59.08	6.1	(7.0)	13.0	(0.3)
	Crude Oil	769,700	72.91	86.11	—	(10.0)	3.3	(0.8)
Receive variable/pay variable	Natural Gas	15,885,000	6.40	6.22	2.9	(0.1)	—	(1.0)
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	759,709	$ 6.41	$ 9.96	$ —	$ (2.6)	$ 0.8	$ (2.1)
	NGL	—	—	—	—	—	—	(0.9)
Receive fixed/pay variable	Natural Gas	2,327,500	4.90	6.63	0.3	(4.2)	—	(5.8)
	NGL	777,750	69.48	61.23	7.1	(0.9)	15.7	—
	Crude Oil	559,980	77.92	88.00	—	(5.3)	0.8	—
Receive variable/pay variable	Natural Gas	1,089,000	6.43	5.87	0.6	—	—	—
Portion of contracts maturing in 2013								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 6.43	$ 2.3	$ —	$ 2.0	$ —
	NGL	141,255	47.45	55.17	—	(1.0)	—	—
	Crude Oil	467,930	86.40	89.49	2.3	(3.6)	3.4	—
Portion of contracts maturing in 2014								
Swaps								
Receive fixed/pay variable	Crude Oil	182,500	$ 88.72	$ 91.30	$ —	$ (0.4)	$ —	$ —

(1) Volumes of Natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and Crude Oil are measured in barrels, or Bbl.

(2) Weighted average prices received and paid 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, 2009 and 2008, 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.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at December 31, 2009 and 2008.

	At December 31, 2009						At December 31, 2008	
					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 2010								
Calls (written)	Natural Gas[4]	365,000	$ 4.31	$ 5.79	$ —	$ (0.6)	$ —	$ (1.0)
Puts (purchased)	Natural Gas[4]	365,000	3.40	5.79	—	—	—	—
	NGL	971,995	44.30	53.69	3.2	—	5.2	—
	Crude Oil	298,935	70.87	82.30	0.6	—	—	—
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas[4]	365,000	$ 4.31	$ 6.33	$ —	$ (0.8)	$ —	$ (1.0)
Puts (purchased)	Natural Gas[4]	365,000	3.40	6.33	—	—	—	—
	NGL	170,820	51.89	46.73	2.4	—	2.7	—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	128,832	$ 66.80	$ 50.34	$ 3.2	$ —	$ 4.4	$ —

(1) Volumes of Natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and Crude Oil are measured in barrels, or 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, 2009 and 2008, 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.

(4) Transactions which, in combination, create a collar, representing a floor and ceiling on the price, which provides long-term price protection.

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.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value at December 31, 2009	Fair Value at December 31, 2008
		(dollars in millions)		(dollars in millions)	
Contracts maturing in 2010					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 250	1.68%	$ (2.5)	$ —
Interest Rate Caps	Non-qualifying	200	1.09%	0.2	—
Contracts maturing in 2011					
Interest Rate Caps	Non-qualifying	$ 200	1.14%	$ 0.3	$ —
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$ 600	4.15%	$ (16.9)	$ —
Interest Rate Swaps—Pay Fixed	Non-qualifying	125	4.35%	(9.2)	(13.5)
Interest Rate Swaps—Receive Fixed	Non-qualifying	125	4.75%	11.0	15.3
Contracts settling prior to maturity					
2010—Pre-issuance Hedges	Cash Flow Hedge	$ 220	4.62%	$ (6.8)	$ —
2012—Pre-issuance Hedges	Cash Flow Hedge	600	4.57%	24.9	—
2013—Pre-issuance Hedges	Cash Flow Hedge	300	4.62%	14.1	—

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

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at December 31, 2009 for each of the indicated calendar years:

	Notional Amount	2010	2011	2012	2013	2014	Thereafter	Total
				(dollars in millions)				
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$ 975.0	$ (7.9)	$ (14.5)	$ (5.3)	$ (0.9)	$ —	$ —	$ (28.6)
Fixed to Floating	125.0	5.4	3.4	1.7	0.5	—	—	11.0
Pre-issuance hedges	1,120.0	(6.8)	—	24.9	14.1	—	—	32.2
Interest Rate Caps	400.0	0.5	—	—	—	—	—	0.5
		$ (8.8)	$ (11.1)	$ 21.3	$ 13.7	$ —	$ —	$ 15.1

16. INCOME TAXES

We are not a taxable entity for U.S. federal income tax purposes, or for the majority of states that impose an income tax. These taxes on our net income are generally borne by our unitholders through the allocation of taxable income. Michigan and Texas within their tax structures impose taxes 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.

Our income tax expense is $8.5 million, $7.0 million and $5.1 million for the years ended December 31, 2009, 2008 and 2007, respectively, which we computed by applying a 0.51% Texas state income tax rate to modified gross margin and a 0.12% Michigan state income tax rate to modified gross receipts. Our income tax expense represents a 2.6%, 1.7% and 2.0% effective rate as applied to pretax book income for December 31, 2009, 2008 and 2007, respectively. At December 31, 2009 and 2008 we have included a current income tax payable of $7.2 million and $5.2 million in "Property and other taxes payable," respectively. In addition, at December 31, 2009 and 2008, we have included a deferred income tax liability of $3.1 million and $2.6 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, 2009, 2008 and 2007, we paid $5.4 million, $5.3 million and zero in income taxes, respectively. As of December 31, 2009, we have no liability reported for unrecognized tax benefits.

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,	
	2009	2008
	(in millions)	
Net book basis of assets in excess of tax basis	$ (3.6)	$ (2.1)
Net book losses (income) on derivatives not recognized for tax purposes	0.5	(0.5)
Net deferred tax liability	$ (3.1)	$ (2.6)

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ended December 2008, 2007, and 2006.

17. 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 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, 2009				
	Liquids	Natural Gas	Marketing	Corporate(1)	Total
			(in millions)		
Total revenue	$ 972.2	$ 3,965.8	$ 2,164.3	$ —	$ 7,102.3
Less: Intersegment revenue	0.4	1,344.9	25.2	—	1,370.5
Operating revenue	971.8	2,620.9	2,139.1	—	5,731.8
Cost of natural gas	—	2,091.5	2,089.3	—	4,180.8
Operating and administrative	248.4	288.6	6.4	5.2	548.6
Power	128.1	—	—	—	128.1
Depreciation and amortization	133.3	123.0	1.4	—	257.7
Operating income	462.0	117.8	42.0	(5.2)	616.6
Interest expense	—	—	—	228.6	228.6
Other income	—	—	—	13.4	13.4
Income from continuing operations before income tax expense	462.0	117.8	42.0	(220.4)	401.4
Income tax expense	—	—	—	8.5	8.5
Income from continuing operations	462.0	117.8	42.0	(228.9)	392.9
Loss from discontinued operations	—	(64.9)	—	—	(64.9)
Net income	462.0	52.9	42.0	(228.9)	328.0
Less: Net income attributable to the noncontrolling interest	—	—	—	11.4	11.4
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 462.0	$ 52.9	$ 42.0	$ (240.3)	$ 316.6
Total assets	$ 5,179.0	$ 3,306.8	$ 242.9	$ 259.6	$ 8,988.3
Capital expenditures (excluding acquisitions)	$ 1,149.1	$ 125.0	$ —	$ 18.0	$ 1,292.1

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the business segments.

	As of and for the year ended December 31, 2008				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 773.4	$ 7,666.6	$ 4,837.4	$ —	$ 13,277.4
Less: Intersegment revenue	0.3	3,150.9	227.5	—	3,378.7
Operating revenue	773.1	4,515.7	4,609.9	—	9,898.7
Cost of natural gas	—	3,864.0	4,590.5	—	8,454.5
Operating and administrative	189.4	306.4	10.1	7.1	513.0
Power	140.7	—	—	—	140.7
Depreciation and amortization	100.8	107.5	1.6	—	209.9
Operating income	342.2	237.8	7.7	(7.1)	580.6
Interest expense	—	—	—	180.6	180.6
Other income	—	—	—	1.9	1.9
Income from continuing operations before income tax expense	342.2	237.8	7.7	(185.8)	401.9
Income tax expense	—	—	—	7.0	7.0
Income from continuing operations	342.2	237.8	7.7	(192.8)	394.9
Income from discontinued operations	—	8.3	—	—	8.3
Net income	$ 342.2	$ 246.1	$ 7.7	$ (192.8)	$ 403.2
Total assets	$ 3,976.7	$ 3,580.2	$ 319.1	$ 424.9	$ 8,300.9
Capital expenditures (excluding acquisitions)	$ 1,054.1	$ 303.6	$ —	$ 17.7	$ 1,375.4

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the business segments.

	As of and for the year ended December 31, 2007				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 548.1	$ 5,695.8	$ 3,527.5	$ —	$ 9,771.4
Less: Intersegment revenue	—	2,363.3	236.0	—	2,599.3
Operating revenue	548.1	3,332.5	3,291.5	—	7,172.1
Cost of natural gas	—	2,919.1	3,256.9	—	6,176.0
Operating and administrative	156.1	241.2	8.0	3.5	408.8
Power	117.0	—	—	—	117.0
Depreciation and amortization	67.9	82.4	1.6	—	151.9
Operating income (loss)	207.1	89.8	25.0	(3.5)	318.4
Interest expense	—	—	—	99.8	99.8
Other income	—	—	—	4.2	4.2
Income from continuing operations before income tax expense	207.1	89.8	25.0	(99.1)	222.8
Income tax expense	—	—	—	5.1	5.1
Income from continuing operations	207.1	89.8	25.0	(104.2)	217.7
Income from discontinued operations	—	31.8	—	—	31.8
Net income	$ 207.1	$ 121.6	$ 25.0	$ (104.2)	$ 249.5
Total assets	$ 2,976.9	$ 3,461.1	$ 349.6	$ 104.0	$ 6,891.6
Capital expenditures (excluding acquisitions)	$ 1,218.8	$ 747.9	$ 1.6	$ 11.9	$ 1,980.2

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the business segments.

18. REGULATORY MATTERS

Regulatory Accounting

In April 2009, we began applying the authoritative accounting provisions applicable to the regulated operations of our Southern Access Project, when the facilities rate surcharge associated with the project was both approved by the FERC and uncontested by any of our customers. The rates for the Southern Access Project 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 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. During 2009 we have under collected revenue related to our Southern Access Project in-part because actual volumes have been lower than the forecast volumes used to calculate the toll surcharge. 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 or settled as cash 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 our customers and the regulator. For the year ended December 31, 2009, we recognized \$7.5 million of additional revenue on our consolidated statements of income, along with a corresponding regulatory receivable on our consolidated statement of financial position at December 31, 2009 related to the difference in transportation volumes. These revenues were earned during 2009, but will not be realized as cash until 2010 when we update our transportation rates to account for the lower actual delivered volume than estimated.

On August 20, 2009, our Alberta Clipper Project received the Presidential Border Crossing Permit from the U.S. Department of State, which will allow crude oil that will be shipped on the mainline system in Canada to cross the international border near Neche, North Dakota and be transported on the Alberta Clipper pipeline into the United States. The permit enables our planned construction of the Alberta Clipper Project to continue and ultimately, when completed, allows us to institute a cost-of-service model to recover the costs of construction from our customers through the transportation rates we will charge. As a result, we began applying the authoritative accounting provisions applicable to the regulated activities of our Alberta Clipper Project. We are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with construction of the Alberta Clipper Project, we recorded \$12.6 million of AEDC in "Property, plant and equipment" on our consolidated statement of financial position at December 31, 2009, and a corresponding \$12.6 million of "Other income," in our consolidated statement of income for the year ended December 31, 2009.

FERC Transportation Tariffs-Liquids

Effective April 1, 2009, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimates and actual cost and throughput data for the prior year and our projected costs and throughput for 2009 related to our expansion projects. The projected costs for 2009 include three additional projects, the most significant being the Southern Lights replacement capacity project. The projected costs also include a rate update for two existing projects including the Hartsdale tanks charge and the Southern Access Project for the inclusion of the recently completed Stage 2 of the project. This filing increased the average transportation rate for crude oil movements from the Canadian border to Chicago by approximately \$0.15 per barrel, to an average of approximately \$1.41 per barrel. In May 2009 we began realizing revenues in relation to this increased surcharge as crude oil was delivered from our pipeline.

Effective May 1, 2009, we filed a tariff with the FERC to reflect the addition of Flanagan as a delivery point on our Lakehead system. The new delivery point is a component of the Southern Access Project. Notwithstanding the new rates for the delivery point at Flanagan, all rates in this tariff filing remain unchanged from the tariff filing effective April 1, 2009, discussed above. The average transportation rate for crude oil movements from the Canadian border to Flanagan will be approximately \$1.41 per barrel, which is the same as other points in the Chicago region.

Effective July 1, 2009, 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 March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five-year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates and does not apply to the SEP II, Terrace and Facilities surcharges, which includes the Southern Access Project. Effective July 2009, we increased the base tariff rates on our Lakehead system by an average of 7.6 percent to equal the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche to Chicago is $1.46 per barrel, which reflects a $0.05 per barrel increase over the rates filed effective April 1, 2009. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 7.6 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

19. SUBSEQUENT EVENTS

We have evaluated events subsequent to December 31, 2009 through February 18, 2010, the date the financial statements were available to be issued, and identified the events disclosed below.

Distribution to Partners

On January 29, 2010, the board of directors of Enbridge Management declared a distribution payable to our partners on February 12, 2010. The distribution was paid to unitholders of record as of February 5, 2010, of our available cash of $131.7 million at December 31, 2009, or $0.99 per limited partner unit. Of this distribution, $115.2 million was paid in cash, $16.2 million was distributed in i-units to our i-unitholder, and $0.3 million was retained from the General Partner in respect of the i-unit distribution to maintain its two percent general partner interest.

Lakehead Line 2b Leak

On January 8, 2010, an unexpected release on Line 2b of our Lakehead system occurred in Pembina County, North Dakota. We immediately shut down our pipelines in the vicinity and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline. We completed the excavation and repairs and returned the line to service within five days. Line 2b was restarted January 13, 2010, once repairs on the pipeline were completed. The volume of oil released was approximately 3,000 barrels, which was largely contained in an area surrounding the pipeline leak. We continue to work with federal and state environmental and pipeline safety regulators to investigate the cause of the leak. We have the potential of incurring additional costs in connection with this incident, including expenditures necessary to remediate any operating condition that is determined to have caused the incident. We do not expect the costs related to the containment, cleanup and repair of the pipeline to significantly impact our operating results, cash flows or financial position.

Regulatory—North Dakota Tariff Filing

Effective January 1, 2010, we increased the rates for transportation on our North Dakota system to include a new surcharge related to the recent completion of our Phase VI Expansion program, which increased capacity on the pipeline from 110,000 Bpd to 161,000 Bpd. This surcharge is applicable for the seven years immediately following the January 1, 2010 in-service date of the Phase VI Expansion program. The mainline expansion surcharge is applied to all mainline volumes with a destination of Clearbrook and the looping surcharge is applied to all volumes originating at Trenton and Alexander, North Dakota. The rates and surcharges for transportation of light crude oil to principal delivery points via trunklines on the Enbridge North Dakota System are set forth below:

	Published Rate per Barrel FERC No. 61[1]	Phase VI Surcharge Per Barrel	Published Rate per Barrel FERC No. 64[2]
From Glenburn, Haas, Minot, Newberg, Sherwood, Stanley and Wiley, North Dakota to Clearbrook, Minnesota	$ 1.0495	$ 0.6078	$ 1.6573
From Brush Lake and Dwyer, Montana and Grenora, North Dakota to Clearbrook, Minnesota	1.1763	0.6078	1.7841
From Clear Lake, Dagmar, Flat Lake and Reserve, Montana to to Clearbrook, Minnesota	1.2043	0.6078	1.8121
From Tioga, North Dakota to Clearbrook, Minnesota	1.0774	0.6078	1.6852
From Trenton and Missouri Ridge, North Dakota to Clearbrook, Minnesota	2.0130	0.6078	2.6208
From Alexander, North Dakota to Clearbrook, Minnesota	2.0550	0.6078	2.6628
From Brush Lake, Dagmar and Clear Lake, Montana to Tioga, North Dakota	0.5496	—	0.5496
From Reserve, Montana to Tioga, North Dakota	0.6200	—	0.6200
From Trenton and Missouri Ridge, North Dakota to Tioga, North Dakota	1.2171	—	1.2171
From Alexander, North Dakota to Tioga, North Dakota	1.2589	—	1.2589

(1) Pursuant to FERC Tariff No. 61 as filed with the FERC on May 29, 2009, with an effective date at July 1, 2009.

(2) Pursuant to FERC Tariff No. 64 as filed with the FERC on November 30, 2009 with an effective date of January 1, 2010.

20. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for our "Adjustments to reconcile net income to net cash provided: Other" balance in our consolidated statements of cash flows.

	For the year ended December 31,		
	2009	2008	2007
		(in millions)	
Discount accretion	$ 0.6	$ 11.5	$ 3.8
Environmental liabilities	4.9	5.9	(2.0)
Amortization of debt issuance and hedging costs	17.3	7.4	—
Deferred income taxes	1.2	1.3	0.2
Allowance for equity used during construction	(12.6)	—	—
Other	0.7	(0.6)	(0.2)
	$ 12.1	$ 25.5	$ 1.8

21. QUARTERLY FINANCIAL DATA (Unaudited)

	First[(1)(2)]	Second[(2)]	Third	Fourth[(1)]	Total
		(in millions, except per unit amounts)			
2009 Quarters					
Operating revenue	$ 1,441.2	$ 1,299.3	$ 1,363.7	$ 1,627.6	$ 5,731.8
Operating income	$ 122.0	$ 177.3	$ 188.0	$ 129.3	$ 616.6
Income from continuing operations	$ 68.2	$ 117.5	$ 127.4	$ 79.8	$ 392.9
Income (loss) from discontinued operations	$ 0.4	$ —	$ (67.9)	$ 2.6	$ (64.9)
Net income	$ 68.6	$ 117.5	$ 59.5	$ 82.4	$ 328.0
Net income attributable to noncontrolling interest	$ —	$ —	$ 2.3	$ 9.1	$ 11.4
Net income attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 68.6	$ 117.5	$ 57.2	$ 73.3	$ 316.6
Net income per limited partner unit	$ 0.47	$ 0.88	$ 0.37	$ 0.50	$ 2.24
2008 Quarters					
Operating revenue	$ 2,402.9	$ 2,871.6	$ 2,770.2	$ 1,854.0	$ 9,898.7
Operating income	$ 129.4	$ 105.5	$ 169.0	$ 176.7	$ 580.6
Income from continuing operations	$ 100.2	$ 54.0	$ 116.6	$ 124.1	$ 394.9
Income (loss) from discontinued operations	$ 2.9	$ 4.8	$ 2.8	$ (2.2)	$ 8.3
Net income	$ 103.1	$ 58.8	$ 119.4	$ 121.9	$ 403.2
Net income per limited partner unit	$ 0.99	$ 0.49	$ 1.04	$ 1.04	$ 3.64

(1) In the first and fourth quarter of 2009, we recognized $13.5 million and $9.0 million, respectively, of revenues related to the differences identified on the Mustang pipeline system as discussed in Note 14 – *Joint Tariff Revenues.*

(2) The following table presents the operating results of the non-core natural gas assets we sold in November 2009 for the first and second quarters of 2008 and 2009, which have been excluded from the quarterly financial data presented above, to reconcile to the operating results we previously presented in our quarterly reports on Form 10-Q.

	2009 Quarters		2008 Quarters	
	First	Second	First	Second
	(in millions)			
Operating revenue	$ 18.5	$ 10.9	$ 32.4	$ 60.6
Operating income	$ 0.4	$ (0.1)	$ 2.9	$ 4.0
Income from continuing operations	$ 0.4	$ —	$ 2.9	$ 4.8
Income (loss) from discontinued operations	$ (0.4)	$ —	$ (2.9)	$ (4.8)
Net income	$ —	$ —	$ —	$ —

Exhibit 31.1

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

I, Stephen J. J. Letwin, 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(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2010

By: /s/ STEPHEN J. J. LETWIN

Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

Exhibit 31.2

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(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2010

By: /s/ MARK A. MAKI

Mark A. Maki
Vice President, Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

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, 2009 (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 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 18, 2010

By: /S/ STEPHEN J. J. LETWIN

Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

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 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, 2009 (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 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 18, 2010

By: /S/ MARK A. MAKI

Mark A. Maki
Vice President, Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

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