

For the nine months ended September 30, 2006

Enbridge reports nine-month earnings of \$444.3 million

Highlights

- Adjusted operating earnings for the third quarter increase 25% to \$92.3 million
- Adjusted operating earnings for the nine months increase 12% to \$420.5 million
- Ownership interest in EEP increases with US\$250 million investment
- Construction continues on Athabasca lateral pipelines and terminals
- Construction commences on the Southern Access pipeline expansion

On November 1, 2006, Enbridge Inc. announced its earnings for the nine months ended September 30, 2006. “Enbridge delivered a 12% increase in adjusted earnings per common share in the first nine months of 2006,” said Patrick D. Daniel, President & Chief Executive Officer of Enbridge Inc. “In light of this strong earnings performance we expect full year 2006 adjusted operating earnings to be within our previously noted \$1.65 to \$1.75 per share range. This continued earnings growth, combined with our new infrastructure projects already under construction and the many other attractive opportunities currently under development, will create value for customers and shareholders.”

On October 31, 2006, the Enbridge Board of Directors declared quarterly dividends of \$0.2875 per common share and \$0.34375 per Series A Preferred Share. Both dividends are payable on December 1, 2006 to shareholders of record on November 15, 2006.

SHAREHOLDER INFORMATION

Registrar and Transfer Agent in Canada

Inquiries regarding the Dividend Reinvestment and Share Purchase Plan, change of address, share transfer, lost certificates, dividends, and duplicate mailings should be directed to:

CIBC Mellon Trust Company
199 Bay Street
Commerce Court West, Securities Level
Toronto, Ontario M5L 1G9
Telephone: (416) 643-5500
Toll free: (800) 387-0825

Dividend Reinvestment & Share Purchase Plan

Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their

cash dividends in common shares, or to make optional cash payments to purchase additional shares, in either case free of brokerage or other charges. Share purchase cut-off for the 2006 fourth quarter optional cash payment to purchase additional shares is November 24, 2006.

Investor Relations

Shareholder inquiries regarding the Company's financial and operating performance should be directed to:

Investor Relations
Enbridge Inc.
3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804
Internet: www.enbridge.com

November 1, 2006

Enbridge Inc.

Management's Discussion & Analysis

For the Three and Nine Months Ended September 30, 2006

This Management's Discussion and Analysis, dated October 31, 2006, should be read in conjunction with the unaudited consolidated financial statements of Enbridge Inc. as at and for the three and nine months ended September 30, 2006 and the Management's Discussion and Analysis included in the Company's 2005 Annual Report.

Consolidated Earnings

<i>(millions of Canadian dollars)</i>	Three months ended		Nine months ended	
	September 30, 2006	2005	September 30, 2006	2005
Liquids Pipelines	68.1	61.6	203.0	168.2
Gas Pipelines	15.1	9.9	47.0	46.9
Sponsored Investments	21.9	11.4	65.3	44.3
Gas Distribution and Services	(11.4)	(20.8)	108.6	109.9
International	21.1	21.0	64.2	59.6
Corporate	(19.3)	(15.3)	(43.8)	(46.9)
	95.5	67.8	444.3	382.0

Earnings applicable to common shareholders were \$444.3 million for the nine months ended September 30, 2006, or \$1.31 per share, compared with \$382.0 million or \$1.13 per share in 2005. The \$62.3 million increase in earnings was attributed to strong performances from the Enbridge crude oil mainline system and the Aux Sable natural gas fractionation facility, as well as \$48.9 million from the revaluation of future income tax balances due to tax rate reductions. These positive factors were partially offset by a lower contribution from the gas distribution utility, as weather in the Ontario market area was significantly warmer than normal.

Earnings applicable to common shareholders were \$95.5 million for the three months ended September 30, 2006, or \$0.28 per share, compared with \$67.8 million, or \$0.20 per share in 2005. The Aux Sable natural gas fractionation facility and Enbridge Energy Partners contributed to the \$27.7 million increase in earnings. In contrast, two severe hurricanes in 2005 weakened the earnings contribution from the natural gas gathering and transmission assets in the Gulf of Mexico in the prior year.

FORWARD LOOKING INFORMATION

Certain information provided in this Management's Discussion and Analysis (MD&A) constitutes forward-looking statements. The words "anticipate", "expect", "project", "estimate", "forecast" and similar expressions are intended to identify such forward-looking statements. Although Enbridge believes that these statements are based on information and assumptions which are current, reasonable and complete, these statements are necessarily subject to a variety of risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions and commodity prices. You can find a discussion of those risks and uncertainties in our Canadian securities filings and American SEC filings. While Enbridge makes these forward-looking statements in good faith, should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary significantly from those expected. Except to the extent required by applicable securities laws and regulations, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made herein or otherwise, whether as a result of new information, future events or otherwise.

Significant after-tax non-operating factors and variances affecting consolidated earnings were as follows:

<i>(millions of Canadian dollars)</i>	Three months ended		Nine months ended	
	September 30, 2006	2005	September 30, 2006	2005
Sponsored Investments				
Dilution gain on EEP unit issuance	–	–	–	4.6
EEP non-cash derivative fair value gains/(losses)	2.7	(5.9)	5.1	(5.9)
Revalue future income taxes due to tax rate changes	–	–	6.0	–
Gas Distribution and Services				
Colder/(warmer) than normal weather affecting EGD	0.5	(0.2)	(30.2)	1.5
Dilution gain in Noverco (Gaz Metro unit issuance)	–	–	–	7.3
Revalue future income taxes due to tax rate changes	–	–	28.9	–
Corporate				
Revalue future income taxes due to tax rate changes	–	–	14.0	–
Total significant after-tax non-operating factors and variances increasing/(decreasing) earnings	3.2	(6.1)	23.8	7.5

Significant operating factors affecting consolidated earnings in 2006 included the following:

- Enbridge crude oil mainline system earnings were higher primarily due to lower oil loss costs, higher earnings from Terrace and the Incentive Tolling Settlement (ITS).
- Enbridge Energy Partners (EEP) earnings have increased significantly with higher crude oil throughput, strong margins and increased volumes in the natural gas gathering and processing businesses.
- Aux Sable has experienced strong natural gas processing margins throughout the year and earnings under the upside sharing agreement were recorded in the third quarter.

The Company has foreign currency denominated earnings, primarily from U.S. based operations and investments, as well as its Euro investment in CLH. The Company uses long-term derivative contracts to economically hedge a significant portion of the cash distributions from these long-term investments. However, this does not eliminate the GAAP earnings volatility caused by exchange rate differences. During the nine months ended September 30, 2006, the Company received foreign currency denominated cash distributions and settled associated hedge transactions resulting in \$13.8 million (2005 - \$9.9 million) of incremental cash flows, which was not included in reported earnings.

RECENT DEVELOPMENTS

Liquids Pipelines – Progress on Organic Growth Projects

The Liquids Pipelines strategy focuses on meeting the needs of Western Canadian oil producers by providing market access for the projected increases in Alberta oil sands production. This strategy includes continuing to develop Alberta oil sands infrastructure, enhancing producer access to diluent and providing increased access to new and traditional markets. The Company continued to advance these objectives throughout the third quarter of 2006.

Waupisoo Pipeline

The \$400 million Waupisoo Pipeline Project continues to progress with a targeted in-service date of June 2008. Enbridge had filed an application for regulatory approval with the Alberta Energy & Utilities

Board and is awaiting a decision. The previously announced diluent line has been separated from the regulatory filing in order to expedite the crude oil line, which is needed earlier. Enbridge will continue discussions with all interested parties regarding a diluent line, with construction and an in-service date to be determined at a later date.

Athabasca Pipeline Expansion and Related Lateral Projects

Construction of the Surmont laterals and facilities is complete and awaiting first production, which is expected in early 2007. The other Athabasca Pipeline projects, including the Long Lake laterals and additional pumping facilities, are expected to be completed at the end of 2006 or early in 2007.

Southern Access Mainline Expansion

During the first quarter of 2006, the Federal Energy Regulatory Commission (FERC) approved an Offer of Settlement with respect to tolls for the U.S. segment of the Southern Access Expansion. The Settlement allows the Lakehead System, the portion of the mainline owned by EEP in the United States, to recover the costs associated with the Expansion through a surcharge in addition to existing base rates. The surcharge will be a transparent cost-of-service-based tariff mechanism that EEP will adjust each year to actual costs and throughput.

The first phase of the Southern Access Expansion project in Canada has been expedited and is now expected to add approximately 120,000 barrels per day (bpd) of capacity by the end of 2006, rather than 2007. Subsequent phases are expected to increase the cumulative additional capacity to 148,000 bpd in 2008 and 400,000 bpd in 2009.

In the second quarter of 2006, Enbridge and EEP reached agreement with shippers and the Canadian Association of Petroleum Producers (CAPP) to increase the proposed diameter of the Southern Access Expansion between Superior, Wisconsin and Flanagan, Illinois to a 42-inch diameter, increasing the estimated capital cost of the Southern Access Expansion in both Canada and the United States to approximately US\$1.3 billion. The pipe diameter increase, in conjunction with the proposed Alberta Clipper Pipeline, will position the system for low-cost future expansion.

Alberta Clipper Pipeline

Shipper interest in the proposed heavy crude Alberta Clipper Pipeline continues to be strong. Enbridge and EEP will seek to reach agreement with shippers on the project terms in time to file regulatory applications in late 2006 or early 2007, maintaining the option to achieve an in-service date in the fourth quarter of 2009. The Alberta Clipper Pipeline would involve the construction of a 36-inch diameter sixth pipeline from Hardisty, Alberta to Superior, Wisconsin, in conjunction with additional pumping power applied to the new 42-inch pipe from Superior to Flanagan, Illinois, described above under Southern Access Expansion. The expected capacity of the pipeline has been increased to 450,000 bpd. The Canadian segment of the line is expected to cost US\$1,150 million (in 2006 dollars) and the U.S. segment, which would be undertaken by EEP, is expected to cost US\$750 million.

Southern Access Extension

Discussions with shippers regarding the Southern Access Extension from Flanagan, Illinois to Patoka, Illinois have been finalized. CAPP supports the Extension, which includes a new 36-inch diameter, 400,000 bpd pipeline at a cost of approximately US\$350 million. The Extension will be undertaken by Enbridge and is targeted to be in service in 2009. With CAPP support for this project received on July 17, 2006, a FERC Offer of Settlement was filed on September 1, 2006.

Spearhead Pipeline

Following its acquisition and reversal construction, Spearhead Pipeline commenced delivery of crude oil from Chicago, Illinois to Cushing, Oklahoma in March 2006. The performance of the Spearhead

Pipeline has continued to surpass the Company's expectations. Throughput on the pipeline continues to increase with nominations in October 2006 exceeding the pipeline's 125,000 bpd capacity. This has put the pipeline into apportionment for the first time since it commenced operation in March 2006. The Company is currently evaluating the potential to expand the Spearhead Pipeline in 2007. Two expansion alternatives are under consideration, with the smaller expansion bringing total capacity to 190,000 bpd.

U.S. Gulf Coast Initiatives

The Company continues to meet with industry to explore and develop various options to enhance access to the U.S. Gulf Coast for Canadian supply. There is general agreement that incremental pipeline capacity will be necessary given the projected increase in Canadian production. The Company is examining greenfield pipeline options as well as the use of existing pipelines that may be candidates for reversal or expansion. In addition to the Gateway Pipeline project to the west coast and the Alberta Clipper Pipeline project, which could provide large incremental export capacity, the Company has had discussions with customers who have expressed an interest in taking capacity on a new US\$3.6 billion, 400,000 bpd pipeline, which could transport oil from Alberta directly to Texas. This pipeline would also connect to refining centers in Denver, Colorado and Cushing, Oklahoma. The development of a number of alternative large diameter pipeline initiatives allows shippers to choose the projects that best meet their needs. Enbridge will only proceed with projects supported by shippers.

Gateway Pipeline Project

Current shipper preferences and the demand to accelerate the development of capacity to traditional U.S. markets will likely result in the Alberta Clipper Pipeline project preceding the Gateway Pipeline project. The Company now estimates that the in-service date will likely be in the 2012 to 2014 timeframe. This project includes a 400,000 bpd petroleum export line which would transport oil from the Edmonton, Alberta area to Kitimat, British Columbia where it could be shipped by tanker to China, other Asia-Pacific markets and California. The project also includes a condensate import line, which would bring imported condensate from Kitimat, British Columbia to the Edmonton, Alberta area. Interest expressed by shippers during the 2005 Open Seasons resulted in upsizing the petroleum export line from 30 to 36 inches in diameter. The size of the condensate line has been increased from 16 to 20 inches. The decision to proceed with the regulatory filing for either pipeline is subject to commercial considerations, including satisfactory completion of shipper agreements, environmental assessment as well as public and Aboriginal consultation.

Southern Lights Pipeline

In response to interest expressed by a number of shippers to increase the availability of diluent in Alberta, Enbridge announced plans to build the Southern Lights Pipeline. If completed as currently planned, this 180,000 bpd pipeline would transport diluent from Chicago, Illinois to Edmonton, Alberta and would be in service in 2009. Diluent is required to transport heavy oil and bitumen produced in Alberta.

Further optimization of the design has also identified an upsizing opportunity for the diluent line from 16 to 20 inches in diameter. This optimization caused a minor increase in capital cost, but will result in substantial power cost savings once the pipeline is operational. This modification of the Southern Lights project has been reviewed and endorsed by shippers due to the increase in ultimate capacity and lower tolls from savings in power costs.

The Southern Lights Pipeline project also involves reversing the flow of Enbridge's Line 13, which is an existing crude oil pipeline, from Clearbrook, Minnesota to Edmonton, the construction of a new 20-inch diameter pipeline to transport crude oil from Cromer, Manitoba to Clearbrook and the expansion of existing Line 2. These changes to the existing crude oil system would increase southbound light crude

system capacity by 45,000 bpd. The baseline cost estimate, including the 20-inch diameter diluent pipeline, is US\$1.3 billion.

Endorsement of the proposed Line 13 reversal is being considered by the CAPP. Final endorsement is being sought during the fourth quarter of 2006 to avoid potential delays to the project. Following receipt of the CAPP endorsement, applications to the National Energy Board, FERC and other regulatory agencies will commence. The approval of the Board of Directors of EEP is required to exchange the portion of Line 13 currently owned by EEP for a portion of the Cromer to Clearbrook crude oil pipeline to be constructed.

Hardisty Terminal

During the second quarter of 2006, the Company announced its plan to proceed with the construction of a new crude oil terminal at Hardisty, Alberta. A second phase expansion was approved by the Board of Directors in July of 2006.

The terminal is now expected to have a capacity of 7.5 million barrels and will cost approximately \$375 million. The Company has executed contracts for over 50% of the expanded capacity and believes it is close to closing contracts for the balance of the capacity. It is anticipated that the terminal will start to come into service early in 2008, with tanks being commissioned throughout 2008 and into 2009.

Downstream Terminaling

The Company continues to advance many downstream terminaling projects, including an estimated US\$55 million EEP-sponsored project at Cushing with an estimated 2007 in-service date. Enbridge is pursuing several other terminaling projects estimated at US\$130 million with in-service dates of 2007 and 2008.

Gas Pipelines – Developments

One of the Company's Gas Pipelines' strategies is to capitalize on its offshore Gulf of Mexico assets (Enbridge Offshore Pipelines) through the connection of new gas discoveries and acquisition of other deepwater systems. During the second quarter of 2006, Enbridge acquired, through a 50%-owned joint venture, a 14-mile offshore pipeline, with a capacity of 200 million cubic feet per day (mmcf/d), to transport natural gas from the West Cameron area to its jointly owned Stingray Pipeline.

Shenzi Lateral Project

Enbridge also announced plans to construct a natural gas lateral to connect the new deepwater Shenzi field to existing Gulf of Mexico pipelines. The 11-mile lateral is expected to cost approximately US\$45 million and to have a capacity of 100 million cubic feet per day (mmcf/d). The Shenzi lateral will deliver natural gas through the Company's 22%-owned Cleopatra Pipeline, the 50%-owned Manta Ray Pipeline and the 50%-owned Nautilus Pipeline and is expected to be completed by the end of 2007 with the first gas expected by mid-year 2009. Construction is scheduled in the second half of 2007 to secure the commitment of a lay vessel, which are in high demand, and avoid interference with the producers' development construction in 2008. Construction is on schedule and on budget.

Neptune Project

Construction of the US\$125 million natural gas and crude oil laterals, which will connect the deepwater Neptune oil and gas field to existing Gulf of Mexico pipelines, is now expected to begin in December of this year with sub-sea tie-ins scheduled for the second quarter of 2007 and production is expected to commence in the last half of 2007. Construction is on schedule and on budget.

Vector Pipeline Expansion

The planned expansion of the Vector Pipeline from 1.0 billion cubic feet per day (bcf/d) to 1.2 bcf/d has been approved by the FERC. The expansion involves the construction of two additional compressor stations and is expected to be in service by November 2007.

Project Updates - Power Generation

Construction of the 200-megawatt Ontario wind power project on the eastern shore of Lake Huron will commence once all required approvals are in place, which is anticipated in the fourth quarter of 2006 or early 2007. The project is expected to be operational in late 2007.

Enbridge will not be participating as a partner in the Goreway Power Project. However, Enbridge Gas Distribution (EGD) has received approval from the Ontario Energy Board (OEB) to construct a pipeline to service this facility. The Company will continue to explore gas-fired generation opportunities that are supported by long-term contracts and improve the utilization of existing assets.

EGD – Late Payment Penalties Class Action Proceeding

In July 2006, culminating a 12-year legal case, EGD entered into a settlement agreement with respect to the repayment of a portion of amounts paid to it as late payment penalties. The total amount of late payment penalties billed between April 1994 and February 2002, when the late payment penalty was revised, was approximately \$74 million.

Under the settlement agreement, which must be approved by the Ontario Superior Court of Justice (the Court), EGD would contribute \$9 million to the Winter Warmth Fund (WWF), pay class counsel approximately \$10 million for the plaintiff's legal fees and expenses and pay approximately \$2 million to the Class Proceedings Fund. The WWF provides eligible low-income customers of participating Ontario utilities with financial assistance for the payment of their natural gas and electricity bills.

On September 25, 2006, the Court issued an interim decision in connection with the settlement agreement. While the interim decision was supportive of the overall settlement amount, the parties were encouraged to consider changes to the settlement agreement in order to recognize the Court's authority to approve the amount of class counsel's fees and to provide additional detail regarding the distribution to the WWF.

On October 19, 2006, the parties agreed to amend the settlement agreement in accordance with the Court's direction. The Court will likely hold a hearing to consider the amended settlement agreement during November 2006.

In accordance with the terms of the settlement agreement, EGD has paid an initial amount of \$2 million pending final approval of the settlement by the Court. In the event that the Court does not approve the settlement, the amount of \$2 million will be refunded. EGD has recorded a liability for the remaining \$19 million in respect of this settlement under accounts payable, along with a corresponding receivable from ratepayers for the total amount of \$21 million, included in deferred amounts and other assets. EGD will apply to the OEB for recovery of payments resulting from the settlement.

EGD - 2007 Rate Application and Final 2006 Rates Decision

On August 18, 2006, EGD filed an application with the OEB for approval of the 2007 rates, under a cost of service rate-making methodology. A final decision on this rate application is expected during the second quarter of 2007. The key elements of the application, as well as the key elements of the OEB's decision for 2006, are summarized below:

	Requested for 2007	Approved for 2006
Rate base (millions)	\$3,801	\$3,634
Deemed common equity for regulatory purposes	38%	35%
Rate of return on common equity	8.74%	8.74%

As part of its 2007 rate application, EGD has requested a meaningful increase in rate base reflecting capital expenditure requirements to meet the safety, maintenance and growth obligations. The Company will align its 2007 expenditures with the OEB's decision. EGD has also requested an increase in the equity component of its deemed capital structure for regulatory purposes. The requested 38% equity level reflects changes in EGD's current business risk environment and financial risk position. The rate of return on common equity is calculated with reference to a formula approved by the OEB that incorporates the long bond yield forecast. The rate of return of 8.74% is the current OEB approved return embedded within existing rates. This rate of return will be updated for changes in the forecast yield for long bonds, as the yield impacts the formula, prior to the start of 2007, resulting in a modified final rate of return on common equity that will eventually become applicable for 2007. Given the OEB's scheduled plan to move to incentive regulation, the Company expects 2007 to become the base year for a potential three to five year rate capped plan. The details of such plan are expected to be known in 2007.

The OEB released its decision relating to EGD's 2006 rate application on February 9, 2006. The new rates approved by the OEB's decision resulted in an overall increase in rates of approximately 1% for the average residential customer. One key element of the decision included a capital expenditure budget of \$300 million, compared with EGD's request for capital expenditures of approximately \$460 million.

OUTLOOK

2005 Hurricane Update

Enbridge Offshore Pipelines natural gas volumes recovered to 2005 pre-hurricane levels in the second quarter of 2006 as previously damaged infrastructure and associated production came back on line. Additional producer volumes committed to the systems are also contributing to offset natural reservoir declines.

Repairs to producer-owned upstream facilities on the Mississippi Canyon corridor were completed at the end of the second quarter. Repairs in the Stingray corridor are substantially complete. Insurance coverage partially mitigated the temporary volume losses experienced as volumes returned to pre-hurricane levels. The Company continues to pursue the settlement of claims under its insurance policies for such volume losses and additional costs the Company has incurred to restore the service capacity of these assets. A settlement is anticipated in 2007.

The Company continues to maintain an active risk management program that includes comprehensive insurance coverage. However, given a constrained insurance market, it is anticipated that related costs will increase in the form of higher insurance premiums and deductibles as well as longer waiting periods for business interruption claims. It is expected that the incidence and severity of future windstorm occurrences will dictate future costs and coverage levels in this region.

FINANCIAL RESULTS

Liquids Pipelines

Earnings

<i>(millions of Canadian dollars)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Enbridge System	49.0	45.4	149.9	123.8
Athabasca System	14.0	13.1	40.1	36.8
Spearhead Pipeline	0.4	(0.2)	3.1	(0.8)
Olympic Pipeline	2.2	-	4.8	-
NW System	1.5	2.0	4.1	5.7
Feeder Pipelines and Other	1.0	1.3	1.0	2.7
	68.1	61.6	203.0	168.2

Liquids Pipelines earnings increased \$34.8 million from \$168.2 million for the nine months ended September 30, 2005 to \$203.0 million for the nine months ended September 30, 2006. This increase was due to higher earnings from Enbridge System and Athabasca System as well as the commencement of operations of the Spearhead Pipeline in March 2006. Olympic Pipeline was acquired in February 2006 and is performing as expected. Earnings for the three months ended September 30, 2006 reflected similar factors to the nine month earnings.

The Enbridge System reflected higher earnings from a number of factors including lower oil losses, favourable ITS performance and, within Terrace, lower taxes, higher toll revenues and the impact of higher volumes generating surcharge revenue.

Athabasca System earnings continued to grow as infrastructure additions contributed positively, but were partially offset by higher operating expenses.

Spearhead Pipeline commenced commercial operations in early March, 2006. While volumes have remained strong and consistent with the prior months, third quarter earnings were negatively impacted by the timing of operating costs.

Gas Pipelines

Earnings

<i>(millions of Canadian dollars)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Alliance Pipeline US	7.8	8.0	22.3	24.4
Vector Pipeline	2.5	3.6	9.3	11.6
Enbridge Offshore Pipelines	4.8	(1.7)	15.4	10.9
	15.1	9.9	47.0	46.9

Earnings from Gas Pipelines were consistent with the prior year for the nine months ended September 30, 2006. Improved earnings from Enbridge Offshore Pipelines were partially offset by the negative impact of a stronger Canadian dollar. For the three months ended September 30, 2006, earnings increased \$5.2 million to \$15.1 million, reflecting throughput volumes recovering following Hurricanes Katrina and Rita in the prior year.

Alliance Pipeline US earnings were lower in 2006 primarily due to the stronger Canadian dollar.

Vector Pipeline earnings were also impacted by the stronger Canadian dollar and higher operating costs in the second and third quarters of 2006 due to scheduled integrity inspections required by the regulator within the first six years of operation.

Enbridge Offshore Pipelines earnings were negatively impacted by two severe hurricanes in the third quarter of the prior year. Volumes have returned to pre-hurricane levels in 2006, however, the stronger Canadian dollar, among other factors, partially offset the increased earnings.

Sponsored Investments

Earnings

<i>(millions of Canadian dollars)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Enbridge Income Fund (EIF)	9.8	9.1	27.8	25.8
Enbridge Energy Partners (EEP)	12.1	2.3	31.5	13.9
Dilution gains in EEP	–	–	–	4.6
Revalue future income taxes due to tax rate changes	–	–	6.0	–
	21.9	11.4	65.3	44.3

Sponsored Investments earnings improved \$21.0 million to \$65.3 million for the nine months ended September 30, 2006. The increased earnings were due primarily to improved results from EEP. For the three months ended September 30, 2006, earnings increased \$10.5 million to \$21.9 million, reflecting improved earnings from EEP as well as an increased ownership interest in EEP.

EIF's contribution was comparable with the prior year and reflected modest growth at EIF.

EEP's 2006 results improved significantly, despite the stronger Canadian dollar, and reflected considerably higher liquids throughput on the Lakehead System, higher margins and increased volumes in the natural gas gathering and processing businesses in addition to a higher Enbridge ownership interest. The nine months of 2006 also included \$5.1 million (net to Enbridge) of unrealized mark-to-market gains on derivative financial instruments that do not qualify for hedge accounting treatment (gain of \$2.7 million in the third quarter of 2006 and a loss of \$5.9 million in the third quarter of 2005).

EEP issued partnership units in the first quarter of 2005 and because Enbridge did not fully participate in these offerings, dilution gains resulted. While new units were issued by EEP in the third quarter of 2006, no dilution gains resulted as Enbridge participated in the offering, increasing Enbridge's ownership interest in EEP from 10.9% to 16.6%.

Gas Distribution and Services

Earnings

<i>(millions of Canadian dollars)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Enbridge Gas Distribution (EGD)	(27.8)	(32.9)	25.4	55.4
Noverco	(3.9)	1.9	11.2	21.7
CustomerWorks/ECS	5.7	6.6	16.0	18.9
Other Gas Distribution	(1.2)	(1.0)	4.1	4.9
Enbridge Gas New Brunswick	2.8	1.8	7.1	3.8
Gas Services	(0.9)	(0.8)	(1.2)	(0.9)
Aux Sable	14.9	2.4	16.1	6.2
Other	(1.0)	1.2	1.0	(0.1)
Revalue future income taxes due to tax rate changes	–	–	28.9	–
	(11.4)	(20.8)	108.6	109.9

Earnings from Gas Distribution and Services were \$108.6 million for the nine months ended September 30, 2006, which was consistent with prior year results. The nine month earnings in 2006 reflected the impact of warmer than normal weather at EGD offset by increased earnings at Aux Sable due to positive fractionation margins. For the three months ended September 30, 2006, Gas Distribution and Services results improved \$9.4 million due primarily to the positive fractionation margins at Aux Sable.

EGD's distribution volumes and earnings in 2006 were impacted by warmer weather in Ontario which reduced earnings by \$30.2 million whereas weather was colder than normal and increased earnings by \$1.5 million in the prior year. Weather in the third quarter did not significantly impact earnings in either year.

EGD earnings were also reduced by a lower rate of return on common equity, partially offset by a higher rate base. These factors had a more pronounced effect in the first quarter given it is a high volume distribution period.

EGD's earnings are also effected by variances from the forecast cost of service, including operating and maintenance costs. EGD's costs can vary significantly from quarter to quarter due to many factors including weather, project timelines and the timing of operating and capital expenditures. This provided a slight positive earnings effect in the second and third quarters of 2006.

Noverco earnings were lower in the third quarter as the prior year included a future income tax recovery stemming from the receipt of a significant cash dividend. In addition, the first quarter of the prior year included a \$7.3 million dilution gain from a Gaz Metro LP unit issuance in which Noverco did not participate.

Aux Sable entered into an output arrangement effective January 1, 2006, that substantially eliminates all negative earnings variability. Aux Sable now receives a fixed annual fee and upside sharing above a certain margin level measured on an annual basis. Fractionation margins have been positive throughout 2006, and in the third quarter, the Company recognized earnings under the upside sharing agreement that met the accounting criteria for contingent revenue recognition.

International Earnings

<i>(millions of Canadian dollars)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
CLH	14.5	14.2	42.5	39.8
OCENSA/CITCoI	8.4	8.2	24.7	24.4
Other	(1.8)	(1.4)	(3.0)	(4.6)
	21.1	21.0	64.2	59.6

The Company's international investments continued to show strong performance with no significant variances to note.

Corporate Costs

<i>(millions of Canadian dollars)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Corporate	(19.3)	(15.3)	(57.8)	(46.9)
Revalue future income taxes due to tax rate changes	–	–	14.0	–
	(19.3)	(15.3)	(43.8)	(46.9)

The increase in Corporate costs was primarily due to higher interest expense as a portion of the Company's floating rate debt was repaid through the issuance of long-term fixed rate debt. For the nine months ended September 30, 2006, higher interest expense was offset by the positive impact of future tax rate changes.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to generate sufficient cash from operations to settle liabilities as they come due, finance budgeted investing activities and pay common share dividends throughout 2006. Additional liquidity, if necessary, is available under committed credit facilities or through access to the capital markets.

Operating Activities

Cash from operations for the nine months ended September 30, 2006 was \$1,152.3 million and reflected an increase of \$230.0 million from the same period in the prior year. The increase was primarily due to changes in operating assets and liabilities, which increased \$343.8 million from the nine months ended September 30, 2005 primarily due to changes in working capital of EGD, which fluctuates seasonally and is accentuated by changes in natural gas prices. Before changes in operating assets and liabilities, cash from operations decreased by \$113.8 million. This decrease was primarily due to a special dividend of \$70.6 million from Noverco, received in 2005.

For the three months ended September 30, 2006, cash used in operating activities was \$39.4 million, a decrease in the use of cash of \$59.5 million from the prior year quarter. The difference reflected similar factors as for the nine-month period.

Investing Activities

Cash used for investing activities was \$1,096.1 million (2005 - \$492.0 million) and \$560.9 million (2005 - \$171.7 million) for the nine and three months ended September 30, 2006. The increases in 2006 reflected the purchase of a 65% joint venture interest in Olympic Pipeline for \$101.4 million during the first quarter and the purchase of an additional 5.7% interest in Enbridge Energy Partnership during the third quarter for \$280.2 million, as well as increased expenditures on property, plant and equipment during the nine months ended September 30, 2006. Higher expenditures on property, plant and equipment reflected construction of new laterals on the Gulf of Mexico pipeline infrastructure, planned system expansions on the Athabasca pipeline, construction of the Ontario wind power project and customer additions and system upgrades in EGD.

Financing Activities

The Company's debt to capitalization ratio was 64.4% on September 30, 2006, compared with 64.5% on December 31, 2005.

Financing activities during the nine months ended September 30, 2006 resulted in a use of cash of \$12.1 million, compared with \$375.4 million in the same period in 2005. Financing activities primarily consisted of the issuance of medium term notes by Enbridge and EGD totaling \$800.0 million offset by repayments of \$400.0 million of Enbridge long-term debt in the second quarter of 2006 and the payment of \$302.0 million of common share dividends.

CHANGES IN ACCOUNTING POLICIES

Hedges, Financial Instruments – Recognition and Measurement and Comprehensive Income

New accounting standards will be in effect for fiscal years beginning on or after October 1, 2006 for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company anticipates that the adoption of these standards, on January 1, 2007, will result in the recognition of financial instruments and hedging relationships consistent with similar requirements in the United States, as currently reflected in the Company's United States Accounting Principles note.

SELECTED QUARTERLY FINANCIAL INFORMATION¹

(millions of Canadian dollars,
except per share amounts)

	2006				2005			2004
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue	2,184.9	2,327.2	3,346.7	2,712.8	1,657.1	1,572.4	2,555.8	2,323.6
Earnings applicable to common shareholders	95.5	157.9	190.9	174.0	67.8	93.6	220.6	104.8
Earnings per common share	0.28	0.47	0.56	0.52	0.20	0.27	0.66	0.31
Diluted earnings per common share	0.28	0.46	0.56	0.51	0.20	0.27	0.65	0.30
Dividends per common share	0.2875	0.2875	0.2875	0.2875	0.2500	0.2500	0.2500	0.22875

¹ Quarterly Financial Information has been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.

Revenue fluctuates primarily due to the seasonality of EGD. Typically, EGD's revenue peaks in the winter months during the first quarter and, to a lesser extent, in the fourth quarter when higher volumes are delivered and sold. Also, EGD's revenue and earnings are affected by variations in the weather,

especially in the winter, when warmer or colder than normal temperatures can result in lower or higher distribution volumes, respectively.

Significant items that impacted the quarterly earnings and revenue, in addition to the seasonal fluctuations described above, were as follows:

- Third quarter 2006 earnings reflected higher earnings from Enbridge System, increased earnings from the Company's investment in EEP and the recognition of upside sharing in Aux Sable which resulted from high fractionation margins.
- Second quarter earnings in 2006 included the impact of tax rate reductions, which increased earnings by a total of \$48.9 million. Revenues in the second quarter of 2006 were higher than the second quarter of 2005 due to higher commodity prices and were offset by higher commodity costs, as EGD passes through to customers changes in the price of natural gas.
- First quarter earnings in 2006 reflected improved earnings in the Enbridge System more than offset by lower results from EGD, due primarily to warmer than normal weather. Revenues in the first quarter of 2006 were higher due to higher commodity prices and were offset by higher commodity costs.
- Third quarter earnings in 2005 were negatively impacted by Hurricanes Katrina and Rita and by non-cash losses on the fair value of derivatives in EEP.
- First quarter earnings in 2005 included dilution gains in EEP and within Noverco.
- Fourth quarter earnings in 2004 included an additional quarter for EGD and other gas distribution businesses as the consolidation of these businesses changed from quarter lag to calendar year. Although this quarter included six months of earnings from these businesses, the additional quarter (July – September) is seasonally a summer loss quarter, which reduced earnings in the fourth quarter of 2004.

OUTSTANDING SHARE DATA

	Number of Shares
Common Shares – issued and outstanding (voting equity shares)	351,241,456
Preference Shares, Series A (non-voting equity shares)	5,000,000
Total issued and outstanding stock options (7,225,351 vested)	11,122,001

Outstanding share data information is provided as at October 23, 2006.

The Company has a Shareholder Rights Plan designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person, and any related parties, acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Board of Directors of the Company. Should such an acquisition or announcement occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

Additional information relating to Enbridge Inc., including the Company's Annual Information Form, is available on www.sedar.com.

ENBRIDGE INC. HIGHLIGHTS

<i>(unaudited; millions of Canadian dollars, except per share amounts)</i>	Three months ended		Nine months ended	
	September 30,		September 30,	
	2006	2005	2006	2005
Earnings Applicable to Common Shareholders				
Liquids Pipelines	68.1	61.6	203.0	168.2
Gas Pipelines	15.1	9.9	47.0	46.9
Sponsored Investments	21.9	11.4	65.3	44.3
Gas Distribution and Services	(11.4)	(20.8)	108.6	109.9
International	21.1	21.0	64.2	59.6
Corporate	(19.3)	(15.3)	(43.8)	(46.9)
	95.5	67.8	444.3	382.0
Cash Flow Data				
Cash provided by operating activities before changes in operating assets and liabilities	224.8	251.3	802.3	916.1
Cash provided by operating activities	(39.4)	(98.9)	1,152.3	922.3
Expenditures on property, plant and equipment	269.8	141.5	662.4	341.0
Acquisitions and long-term investments	291.9	28.6	448.2	148.5
Common share dividends	100.6	86.9	302.0	260.7
Per Share Information				
Earnings per Common Share	0.28	0.20	1.31	1.13
Diluted Earnings per Common Share	0.28	0.20	1.30	1.12
Dividends per Common Share	0.2875	0.2500	0.8625	0.7500
Shares Outstanding (millions)				
Weighted Average Common Shares Outstanding			339.6	337.2
Diluted Weighted Average Common Shares Outstanding			342.9	340.7
Operating				
Liquids Pipelines ¹				
Deliveries (thousands of barrels per day)	2,155	1,908	2,121	1,979
Barrel miles (billions)	194	168	579	513
Average haul (miles)	981	959	1,000	949
Gas Pipelines – Average Daily Throughput Volume (millions of cubic feet per day)				
Alliance Pipeline US	1,513	1,556	1,595	1,600
Vector Pipeline	879	982	1,014	1,018
Enbridge Offshore Pipelines	2,265	1,809	2,190	2,285
Gas Distribution and Services ²				
Volumes (billion cubic feet)	45	45	285	309
Number of active customers (thousands)	1,829	1,782	1,829	1,782
Degree day deficiency ³				
Actual	85	23	2,190	2,476
Forecast based on normal weather	58	60	2,498	2,500

1. Liquids Pipelines operating highlights include the statistics of the 16.6% owned Lakehead System and other wholly-owned liquid pipeline operations, excluding Spearhead Pipeline and Olympic Pipeline.
2. Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.
3. Degree-day deficiency is a measure of coldness which is indicative of volumetric requirements of natural gas utilized for heating purposes. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.

ENBRIDGE INC. CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
<i>(unaudited; millions of Canadian dollars, except per share amounts)</i>				
Revenues				
Commodity sales	1,645.0	1,142.1	6,141.5	4,108.0
Transportation	453.5	430.7	1,515.7	1,439.3
Energy services	86.4	84.3	201.6	238.0
	2,184.9	1,657.1	7,858.8	5,785.3
Expenses				
Commodity costs	1,562.4	1,076.9	5,850.0	3,789.9
Operating and administrative	256.6	267.4	759.9	782.0
Depreciation and amortization	145.4	141.2	437.6	427.5
	1,964.4	1,485.5	7,047.5	4,999.4
	220.5	171.6	811.3	785.9
Income from Equity Investments	35.9	3.8	134.0	72.6
Other Investment Income	19.8	17.3	36.8	71.3
Interest Expense	(142.2)	(133.0)	(417.3)	(402.4)
	134.0	59.7	564.8	527.4
Income Taxes	(36.8)	9.8	(115.4)	(140.3)
Earnings	97.2	69.5	449.4	387.1
Preferred Share Dividends	(1.7)	(1.7)	(5.1)	(5.1)
Earnings Applicable to Common Shareholders	95.5	67.8	444.3	382.0
Earnings Per Common Share	0.28	0.20	1.31	1.13
Diluted Earnings Per Common Share	0.28	0.20	1.30	1.12

See accompanying notes to the unaudited consolidated financial statements.

ENBRIDGE INC. CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Nine months ended September 30,	
	2006	2005
<i>(unaudited; millions of Canadian dollars)</i>		
Retained Earnings at Beginning of Period	2,098.2	1,840.9
Earnings Applicable to Common Shareholders	444.3	382.0
Common Share Dividends	(302.0)	(260.7)
Dividends Paid to Reciprocal Shareholder	9.1	8.1
Dividend Reclassification Adjustment	-	51.2
Retained Earnings at End of Period	2,249.6	2,021.5

See accompanying notes to the unaudited consolidated financial statements.

ENBRIDGE INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended September 30,		Nine months ended September 30,	
<i>(unaudited; millions of Canadian dollars)</i>	2006	2005	2006	2005
Cash Provided By Operating Activities				
Earnings	97.2	69.5	449.4	387.1
Depreciation and amortization	145.4	141.2	437.6	427.5
Equity earnings less than/(in excess of) cash distributions	(20.2)	82.8	(63.0)	61.3
Gain on reduction of ownership interest	-	-	-	(15.6)
Future income taxes	(4.6)	(44.5)	(52.7)	40.5
Other	7.0	2.3	31.0	15.3
Changes in operating assets and liabilities	(264.2)	(350.2)	350.0	6.2
	(39.4)	(98.9)	1,152.3	922.3
Investing Activities				
Acquisitions	-	(28.3)	(101.4)	(86.4)
Long-term investments	(291.9)	(0.3)	(346.8)	(62.1)
Additions to property, plant and equipment	(269.8)	(141.5)	(662.4)	(341.0)
Affiliate loans	-	0.5	28.0	(0.1)
Change in construction payable	0.8	(2.1)	(13.5)	(2.4)
	(560.9)	(171.7)	(1,096.1)	(492.0)
Financing Activities				
Net change in short-term borrowings and short-term debt	456.7	377.2	(96.5)	(332.6)
Net change in non-recourse short-term debt of joint ventures	(9.7)	(6.5)	(5.2)	5.4
Long-term debt issues	300.0	-	800.0	620.1
Long-term debt repayments	-	-	(400.0)	(396.9)
Non-recourse long-term debt issued by joint ventures	-	-	2.8	6.8
Non-recourse long-term debt repaid by joint ventures	-	(2.4)	(29.7)	(54.8)
Changes in non-controlling interests	(5.5)	7.4	(25.4)	(4.5)
Common shares issued	10.5	7.5	49.0	46.9
Preferred share dividends	(1.7)	(1.7)	(5.1)	(5.1)
Common share dividends	(100.6)	(86.9)	(302.0)	(260.7)
	649.7	294.6	(12.1)	(375.4)
Increase in Cash and Cash Equivalents	49.4	24.0	44.1	54.9
Cash and Cash Equivalents at Beginning of Period	148.6	136.4	153.9	105.5
Cash and Cash Equivalents at End of Period	198.0	160.4	198.0	160.4

See accompanying notes to the unaudited consolidated financial statements.

ENBRIDGE INC.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

<i>(unaudited; millions of Canadian dollars)</i>	September 30, 2006	December 31, 2005
Assets		
Current Assets		
Cash and cash equivalents	198.0	153.9
Accounts receivable and other	1,595.9	1,900.3
Inventory	910.1	1,021.4
	2,704.0	3,075.6
Property, Plant and Equipment, net	10,723.1	10,466.6
Long-Term Investments	2,187.2	1,842.8
Receivable from Affiliate	149.4	177.0
Deferred Amounts and Other Assets	998.0	894.2
Intangible Assets	238.7	252.6
Goodwill	391.8	367.2
Future Income Taxes	197.8	134.9
	17,590.0	17,210.9
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-term borrowings	642.3	1,074.8
Accounts payable and other	1,620.3	1,624.8
Interest payable	85.7	81.7
Current maturities and short-term debt	331.5	401.2
Current portion of non-recourse long-term debt	57.8	68.2
	2,737.6	3,250.7
Long-Term Debt	7,048.8	6,279.1
Non-Recourse Long-Term Debt	1,565.9	1,619.9
Other Long-Term Liabilities	83.6	91.7
Future Income Taxes	1,023.4	1,009.0
Non-Controlling Interests	695.6	691.0
	13,154.9	12,941.4
Shareholders' Equity		
Share capital		
Preferred shares	125.0	125.0
Common shares	2,399.7	2,343.8
Contributed surplus	14.0	10.0
Retained earnings	2,249.6	2,098.2
Foreign currency translation adjustment	(217.5)	(171.8)
Reciprocal shareholding	(135.7)	(135.7)
	4,435.1	4,269.5
	17,590.0	17,210.9

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These consolidated financial statements do not include all disclosures required for annual financial statements and therefore should be read in conjunction with the consolidated financial statements and notes thereto included in Enbridge Inc.'s 2005 Annual Report. These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's financial statements are described in Note 5. These interim financial statements follow the same significant accounting policies and methods of application as those included in the 2005 Annual Report.

Earnings for interim periods may not be indicative of results for the fiscal year due to the seasonal nature of the gas distribution utility business and other factors.

Certain comparative amounts have been reclassified to conform to the current year's presentation.

1. SEGMENTED INFORMATION

Three months ended September 30, 2006

<i>(millions of Canadian dollars)</i>	Gas						Consolidated
	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Distribution and Services	International	Corporate	
Revenues	254.7	87.2	60.8	1,778.4	3.8	-	2,184.9
Commodity costs	-	-	-	(1,562.4)	-	-	(1,562.4)
Operating and administrative	(93.7)	(24.6)	(13.4)	(113.5)	(4.7)	(6.7)	(256.6)
Depreciation and amortization	(35.8)	(23.5)	(17.5)	(66.7)	(0.3)	(1.6)	(145.4)
	125.2	39.1	29.9	35.8	(1.2)	(8.3)	220.5
Investment and other income	1.6	2.3	20.2	(6.0)	23.8	13.8	55.7
Interest and preferred share dividends	(24.8)	(18.0)	(14.7)	(48.9)	-	(37.5)	(143.9)
Income taxes	(33.9)	(8.3)	(13.5)	7.7	(1.5)	12.7	(36.8)
Earnings applicable to common shareholders	68.1	15.1	21.9	(11.4)	21.1	(19.3)	95.5

Three months ended September 30, 2005

<i>(millions of Canadian dollars)</i>	Gas						Consolidated
	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Distribution and Services	International	Corporate	
Revenues	222.8	83.9	63.3	1,284.3	2.8	-	1,657.1
Commodity costs	-	-	-	(1,076.9)	-	-	(1,076.9)
Operating and administrative	(76.8)	(25.7)	(15.4)	(139.5)	(3.6)	(6.4)	(267.4)
Depreciation and amortization	(37.0)	(21.9)	(17.8)	(62.7)	(0.2)	(1.6)	(141.2)
	109.0	36.3	30.1	5.2	(1.0)	(8.0)	171.6
Investment and other income	0.8	0.3	0.4	(4.4)	23.3	0.7	21.1
Interest and preferred share dividends	(24.5)	(19.9)	(15.2)	(44.6)	-	(30.5)	(134.7)
Income taxes	(23.7)	(6.8)	(3.9)	23.0	(1.3)	22.5	9.8
Earnings applicable to common shareholders	61.6	9.9	11.4	(20.8)	21.0	(15.3)	67.8

Nine months ended September 30, 2006

<i>(millions of Canadian dollars)</i>	Gas						Consolidated
	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Distribution and Services	International	Corporate	
Revenues	748.6	260.3	186.2	6,654.6	9.1	-	7,858.8
Commodity costs	-	-	-	(5,850.0)	-	-	(5,850.0)
Operating and administrative	(263.7)	(71.7)	(46.3)	(352.4)	(12.5)	(13.3)	(759.9)
Depreciation and amortization	(114.5)	(65.9)	(53.5)	(198.8)	(0.7)	(4.2)	(437.6)
	370.4	122.7	86.4	253.4	(4.1)	(17.5)	811.3
Investment and other income	1.6	8.3	46.1	19.7	75.9	19.2	170.8
Interest and preferred share dividends	(75.6)	(55.3)	(44.7)	(143.7)	-	(103.1)	(422.4)
Income taxes	(93.4)	(28.7)	(22.5)	(20.8)	(7.6)	57.6	(115.4)
Earnings applicable to common shareholders	203.0	47.0	65.3	108.6	64.2	(43.8)	444.3

Nine months ended September 30, 2005

<i>(millions of Canadian dollars)</i>	Gas						Consolidated
	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Distribution and Services	International	Corporate	
Revenues	648.7	278.7	185.3	4,664.3	8.3	-	5,785.3
Commodity costs	-	-	-	(3,789.9)	-	-	(3,789.9)
Operating and administrative	(228.0)	(70.0)	(43.5)	(413.5)	(11.7)	(15.3)	(782.0)
Depreciation and amortization	(110.7)	(70.0)	(53.2)	(188.3)	(0.8)	(4.5)	(427.5)
	310.0	138.7	88.6	272.6	(4.2)	(19.8)	785.9
Investment and other income	(0.4)	1.6	31.2	20.8	66.2	24.5	143.9
Interest and preferred share dividends	(73.0)	(62.6)	(46.5)	(131.9)	-	(93.5)	(407.5)
Income taxes	(68.4)	(30.8)	(29.0)	(51.6)	(2.4)	41.9	(140.3)
Earnings applicable to common shareholders	168.2	46.9	44.3	109.9	59.6	(46.9)	382.0

2. LONG-TERM INVESTMENTS

During the third quarter of 2006, the Company acquired 5.4 million Class C units of EEP for \$280.2 million. The Class C units have equal voting rights as Class A and B units and are entitled to quarterly distributions equal to those paid to Class A and B unitholders. Prior to August 15, 2009, distributions will be paid in additional Class C units, where Class C units are valued at the market value of Class A units. After August 15, 2009, distributions will be paid in cash and, subject to the approval of existing Class A unitholders, Class C units will convert to Class A units on a one-for-one basis.

As a result of this additional interest, the Company's effective ownership interest in EEP has increased from 10.9% to 16.6% at September 30, 2006.

3. STOCK-BASED COMPENSATION

During the nine months ended September 30, 2006, 1.6 million (2005 – 1.5 million) Fixed Stock Options (FSOs) were granted to employees at a weighted average exercise price of \$36.47 (2005 – \$31.68). The weighted average grant-date fair value of the FSOs granted during the nine months ended

September 30, 2006 was \$6.30 (2005 - \$5.30)³. Outstanding FSOs expire over a period no later than July 5, 2016. The Company has applied the fair-value based method of accounting for FSOs granted after January 1, 2003. Under this method, earnings include a compensation charge representing the fair value of FSOs granted in years 2003 through 2006 amortized over the vesting period, with a corresponding increase to contributed surplus.

In addition, the Company granted officers 117,900 Performance Stock Units (PSUs) (2005 – 130,130) during the nine months ended September 30, 2006. The PSUs granted in 2006 mature on January 1, 2009. Compensation costs for PSUs are accounted for over the three-year period on a mark-to-market basis, whereby a liability and expense are recorded based on the number of PSUs outstanding, the current market price of the Company's stock, and the Company's performance relative to a specified peer group.

Effective September 1, 2006, the Company implemented a Restricted Stock Unit Plan for incentive compensation and granted 182,457 Restricted Stock Units (RSUs) to certain of the Company's employees. The RSUs granted on September 1, 2006 mature on November 30, 2008, at which time the holders of RSUs will receive cash equal to the current market price of the Company's stock for each RSU held. During the 27 month period, the number of RSUs outstanding is increased to include additional RSUs equal to the number of additional shares that would have been received had the RSUs been treated as shares enrolled in the Dividend Reinvestment Plan (DRIP). Compensation expense for RSUs is accrued over the 27 month period on a mark-to-market basis, whereby a liability and expense are recorded based on the current market price of the Company's stock, the number of RSUs outstanding and adjusted for additional shares issued under the DRIP. Compensation expense recorded for the nine months ended September 30, 2006 for RSUs was \$0.2 million.

If the Company had used the fair-value based method to account for all stock-based compensation granted in fiscal 2002, earnings and earnings per share would have been as follows.

<i>(millions of Canadian dollars, except per share amounts)</i>	Three months ended		Nine months ended	
	September 30, 2006	2005	September 30, 2006	2005
Earnings applicable to common shareholders				
As reported	95.5	67.8	444.3	382.0
Total stock-based compensation expense ¹	(4.0)	(3.2)	(10.3)	(9.1)
Included as an expense in the statement of earnings ²	3.7	2.2	9.2	6.1
Pro forma earnings	95.2	66.8	443.2	379.0
Earnings per share				
As reported	0.28	0.20	1.31	1.13
Pro forma	0.28	0.20	1.30	1.12
Diluted earnings per share				
As reported	0.28	0.20	1.30	1.12
Pro forma	0.28	0.20	1.29	1.11

1. Total stock-based compensation expense if the fair-value based method had been applied since January 1, 2002.
2. Stock-based compensation recognized as an expense in the statement of earnings for all stock-based compensation granted in 2003 through 2006 as a result of the adoption of the fair-value based method on January 1, 2003.
3. The Black-Scholes model was used to calculate the fair-value of the FSOs. Significant assumptions include a risk-free interest rate of 4.15% (2005 – 4.44%) based on the Government of Canada yield corresponding to the expected term, expected volatility of 19% (2005 – 16%) based on the historical volatility of the Company's share price, an expected life of 8 years (2005 – 8 years) based on the Company's historical data on option exercises, and an expected dividend yield of 3.23% (2005 – 3.17%).

4. POST-EMPLOYMENT BENEFITS

Pension Plans

The Company has three Company-funded pension plans, which provide either defined benefit or defined contribution pension benefits, or both, for employees of the Company. The Liquids Pipelines and Gas Distribution and Services pension plans provide defined benefit and/or defined contribution pension benefits to Canadian employees of Enbridge. The Enbridge U.S. pension plan provides defined benefit pension benefits. These pension plans are generally fully funded. The Company also provides post-employment benefits other than pensions (OPEB) for qualifying retired employees which benefits plans are generally unfunded. Costs for the period are presented below.

Net Pension and OPEB Costs Recognized

<i>(millions of Canadian dollars)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Benefits earned during the period	10.8	8.0	32.4	24.2
Interest cost on projected benefit obligations	16.2	15.7	48.5	47.4
Expected return on plan assets	(21.1)	(18.9)	(63.4)	(56.7)
Amortization of unrecognized amounts	3.8	3.1	11.6	9.3
Amount charged to Enbridge Energy Partners L.P.	(2.6)	(2.4)	(7.8)	(7.3)
Pension and OPEB costs recognized	7.1	5.5	21.3	16.9

The above reflects the pension and OPEB cost for all of the Company's benefit plans on an accrual basis. However, in accordance with its ability to recover employee benefit costs on a pay-as-you-go basis for the regulated operations of Gas Distribution and Services, the Company records the cost of such benefits on a cash basis. Using the cash basis for the Gas Distribution and Services plans and the accrual method for other plans, the Company's pension and OPEB costs were \$11.7 million for the nine-month period ended September 30, 2006 (2005 - \$13.6 million) and \$5.8 million for the three-month period ended September 30, 2006 (2005 - \$4.5 million).

5. UNITED STATES ACCOUNTING PRINCIPLES

These consolidated financial statements have been prepared in accordance with Canadian GAAP. The effects of significant differences between Canadian GAAP and U.S. GAAP for the Company are described below.

Earnings and Comprehensive Income

<i>(millions of Canadian dollars, except per share amounts)</i>	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
Earnings under Canadian GAAP	95.5	67.8	444.3	382.0
Stock-based compensation ¹	-	-	-	(6.6)
Tax effect of the above adjustments	-	-	-	2.6
Earnings under U.S. GAAP	95.5	67.8	444.3	378.0
Other Comprehensive Income				
Unrealized net gain/(loss) on cash flow hedges ⁵	(24.8)	68.6	(45.6)	115.8
Foreign currency translation adjustment ⁵	7.7	(67.0)	(44.7)	(32.4)
Comprehensive income	78.4	69.4	354.0	461.4
Earnings per common share	0.28	0.20	1.31	1.12
Diluted earnings per common share	0.28	0.20	1.30	1.11

Financial Position

(millions of Canadian dollars)

	September 30, 2006		December 31, 2005	
	Canada	United States	Canada	United States
Cash ^{3,6}	198.0	448.7	153.9	153.9
Accounts receivable and other ^{3,4,5,6}	1,595.9	2,126.4	1,900.3	1,991.5
Inventory ⁶	910.1	1,104.3	1,021.4	1,021.4
Property, plant and equipment, net ^{3,6}	10,723.1	14,545.7	10,466.6	10,466.6
Long-term investments ^{3,6}	2,187.2	1,336.5	1,842.8	1,842.8
Deferred amounts and other assets ^{2,3,6}	998.0	1,667.3	894.2	2,086.6
Intangible assets ⁶	238.7	341.6	252.6	252.6
Goodwill ⁶	391.8	782.1	367.2	367.2
Accounts payable and other ^{1,3,4,5,6}	1,620.3	2,246.5	1,624.8	1,671.0
Interest payable ^{3,6}	85.7	117.5	81.7	81.7
Current portion of non-recourse debt ^{3,6}	57.8	79.8	68.2	68.2
Long-term debt ^{3,4,5}	7,048.8	7,048.8	6,279.1	6,279.8
Non-recourse long-term debt ^{3,6}	1,565.9	3,601.6	1,619.9	1,619.9
Other long-term liabilities ^{3,6}	83.6	424.0	91.7	91.7
Future income taxes ^{2,3,4,5,6}	1,023.4	1,686.2	1,009.0	2,162.2
Non-controlling interests ⁶	695.6	2,097.5	691.0	691.0
Retained earnings	2,249.6	2,162.4	2,098.2	2,027.6
Contributed surplus ¹	14.0	-	10.0	-
Additional paid-in capital ¹	-	57.9	-	53.9
Foreign currency translation adjustment ⁵	(217.5)	-	(171.8)	-
Accumulated other comprehensive loss ⁵	-	(185.8)	-	(95.5)

1. Stock-based Compensation

Effective January 1, 2006, the Company adopted Financial Accounting Standard 123 Revised 2004 (FAS 123R), Share Based Payment, on a modified prospective basis for U.S. GAAP purposes. FAS 123R requires the use of the fair value method to measure compensation expense for the Company's Fixed Stock Options (FSOs) and Performance Based Options (PBOs) issued after January 1, 2006, as well as for the portion of awards for which the requisite service has not been performed that are outstanding as of January 1, 2006. FAS 123R also requires the use of the fair value method for awards settled in cash, including the Company's Performance Stock Units (PSUs) and Restricted Stock Units (RSUs).

The Company had previously adopted the fair value recognition provisions of the former FAS 123, Share Based Payment, effective January 1, 2003, resulting in the recognition of stock based compensation expense using the fair value method for FSOs and PBOs issued subsequent to that date.

The Company's PSUs do not have a strike price, therefore the fair value is equal to the intrinsic value used for Canadian GAAP purposes, eliminating any differences between Canadian and U.S. GAAP. The intrinsic value represents the difference between the Company's closing share price and the exercise price, multiplied by the dilutive number of options/units. FAS 123R requires the effect of forfeitures to be estimated and recorded at the grant date which is also an acceptable Canadian GAAP alternative. Therefore, there is no impact on net income or cash flow as a result of adopting FAS 123R. However, FAS 123R requires the following additional disclosures.

<i>(in millions of options/units and Canadian dollars)</i>	Number of Options/Units		Aggregate Intrinsic Value	
	2006	2005	2006	2005
Fixed Stock Options				
Options Outstanding at September 30	9.7	9.5	110.8	144.2
Options Exercisable at September 30	5.8	5.3	91.3	98.2
Options Exercised during the period	1.2	1.6	30.7	24.4
Performance Based Options				
Options Outstanding at September 30	1.4	2.1	18.3	33.2
Options Exercisable at September 30	1.2	0.8	14.9	14.8
Options Exercised during the period	0.6	0.4	15.1	7.3
Performance Stock Units				
Units Outstanding at September 30	0.3	0.2	11.9	7.4
Units Exercisable at September 30	-	-	-	-
Units Exercised during the period	-	-	-	-
Restricted Stock Units				
Units Outstanding at September 30	0.2	-	6.6	-
Units Exercisable at September 30	-	-	-	-
Units Exercised during the period	-	-	-	-

Cash of \$24.1 million (2005 - \$27.5 million) and \$10.7 million (2005 - \$7.2 million) was received from the exercise of FSO's and PBO's respectively, for the nine month period ended September 30, 2006. The PSUs and RSUs are paid out at the end of a three-year performance cycle.

As at September 30, 2006, there was \$19.5 million, \$5.7 million and \$6.4 million of unrecognized compensation cost related to the FSOs, the PSUs, and the RSUs, respectively. This is expected to be recognized over a weighted average period of 2.6, 1.0, and 2.1 years for the FSOs, the PSUs and the RSUs, respectively.

2. Future Income Taxes

Under U.S. GAAP, deferred income tax liabilities are recorded for rate-regulated operations, which follow the taxes payable method for ratemaking purposes. As these deferred income taxes are expected to be recoverable in future revenues, a corresponding regulatory asset is also recorded. These assets and liabilities are adjusted to reflect changes in enacted income tax rates. A deferred tax liability of \$652.1 million (2005 - \$718.0 million) is recorded for U.S. GAAP purposes and reflects the difference between the carrying value and the tax basis of property, plant and equipment. Regulated companies following the taxes payable method are not required to record this additional tax liability under Canadian GAAP. To recover the additional deferred income taxes recorded under U.S. GAAP through the ratemaking process, it would be necessary to record incremental revenue of \$931.4 million (2005 - \$1,025.7 million).

3. Accounting for Joint Ventures

U.S. GAAP requires the Company's investments in joint ventures to be accounted for as investments using the equity method, as opposed to proportionately consolidated. However, under an accommodation of the U.S. Securities and Exchange Commission, the accounting for a joint venture need not be reconciled from Canadian to U.S. GAAP if this joint venture is jointly controlled by all owners. Joint ventures in which all owners do not share joint control are reconciled to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or shareholders' equity.

4. Financial Instruments

For U.S. GAAP purposes, FAS 133, Accounting for Derivative Instruments and Hedging Activities, requires that all derivatives be recorded on the balance sheet as either assets or liabilities at their fair value. Changes in the fair value of derivatives are recognized in current period earnings unless specific hedge accounting criteria are met.

The accounting for changes in the fair value of derivatives held for hedging purposes depends on their intended use. For fair value hedges, the effective portion of changes in the fair value of derivative instruments is offset in income against the change in the fair value, attributed to the risk being hedged, of the underlying hedged asset, liability or firm commitment. For cash flow hedges, the effective portion of changes in the fair value of derivative instruments is offset through other comprehensive income, until the variability in cash flows being hedged is recognized in earnings in future accounting periods.

5. Accumulated Other Comprehensive Loss

At September 30, 2006, Accumulated Other Comprehensive Loss of \$185.8 million (2005 - \$63.7 million) consists of an accumulated foreign currency translation balance of \$194.5 million (December 30, 2005 - \$149.8 million) and net unrealized gains of \$8.7 million (December 31, 2005 - \$54.3 million) on derivative financial instruments that qualify as cash flow hedges.

Of the total Accumulated Other Comprehensive Loss of \$185.8 million, the Company estimates that approximately \$25.4 million, representing unrecognized net losses on derivative activities at September 30, 2006, is expected to be reclassified into earnings during the next twelve months and primarily relates to natural gas supply management.

6. Consolidation of a Limited Partnership

In September 2005, the U.S. Emerging Issues Task Force (EITF), reached a consensus on EITF issue 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* (EITF 04-5), addressing when a general partner, or general partners as a group, control and should therefore, consolidate a limited partnership. Under EITF 04-5, a sole general partner is presumed to control a limited partnership when certain conditions are met.

Effective January 1, 2006, the Company adopted, without restatement of prior periods, EITF 04-5. As a result of adopting EITF 04-5, the Company is consolidating its 16.6% interest in Enbridge Energy Partners (EEP). The impact of adopting EITF 04-5, for U.S. GAAP purposes as at and for the three and nine months ending September 30, 2006, is outlined below.

Statement of Financial Position

<i>(millions of Canadian dollars)</i>	September 30, 2006
Cash	282.5
Accounts receivable and other	563.9
Inventory	196.0
Property, plant and equipment, net	3,909.7
Deferred amounts and other assets	27.1
Intangible assets	102.9
Goodwill	390.3
	<hr/> 5,472.4
Less: Liabilities	
Accounts payable and other	697.3
Current portion of non-recourse long-term debt	34.5
Non recourse long-term debt	2,035.7
Other long-term liabilities	345.9
Non-controlling interests	1,401.9
	<hr/> 957.1
Elimination of investment in EEP	(957.1)
Net financial position impact	<hr/> nil <hr/>

Statement of Earnings <i>(millions of Canadian dollars)</i>	Three months ended September 30, 2006	Nine months ended September 30, 2006
Transportation revenue	1,715.3	5,490.1
Commodity costs	(1,416.4)	(4,644.4)
Operating and administrative	(137.9)	(379.1)
Depreciation and amortization	(38.9)	(115.0)
Investment and other income	2.2	8.4
Interest expense	(32.0)	(95.2)
Non-controlling interest	(60.9)	(179.2)
	31.4	85.6
Elimination of EEP investment income	(31.4)	(85.6)
Net earnings impact	nil	nil

Statement of Cash Flows <i>(millions of Canadian dollars)</i>	Three months ended September 30, 2006	Nine months ended September 30, 2006
Operating activities	62.6	252.7
Investing activities	(243.2)	(600.3)
Financing activities	363.2	525.4
Net cashflow impact	182.6	177.8

6. COMMITMENTS AND CONTINGENCIES

EGD Late Payment Penalties Class Action Lawsuit

In July 2006, culminating a 12-year legal case, EGD entered into a settlement agreement with respect to the repayment of a portion of amounts paid to it as late payment penalties. The total amount of late payment penalties billed between April 1994 and February 2002, when the late payment penalty was revised, was approximately \$74 million.

Under the settlement agreement, which must be approved by the Ontario Superior Court of Justice (the Court), EGD would contribute \$9 million to the Winter Warmth Fund, pay class counsel approximately \$10 million for the plaintiff's legal fees and expenses and pay approximately \$2 million to the Class Proceedings Fund. The Winter Warmth Fund provides eligible low-income customers of participating Ontario utilities with financial assistance for the payment of their natural gas and electricity bills.

On September 25, 2006, the Court issued an interim decision in connection with the settlement agreement. While the interim decision was supportive of the overall settlement amount, the parties were encouraged to consider changes to the settlement agreement in order to recognize the Court's authority to approve the amount of class counsel's fees and to provide additional detail regarding the distribution to the WWF.

On October 19, 2006, the parties agreed to amend the settlement agreement in accordance with the Court's direction. The Court will likely hold a hearing to consider the amended settlement agreement during November 2006.

In accordance with the terms of the settlement agreement, EGD has paid an initial amount of \$2 million pending final approval of the settlement by the Court. In the event that the Court does not approve the settlement, the amount of \$2 million will be refunded. EGD has recorded a liability for the remaining \$19 million in respect of this settlement under accounts payable, along with a corresponding receivable from ratepayers for the total amount of \$21 million, included in deferred amounts and other assets. EGD will apply to the Ontario Energy Board for recovery of payments resulting from the settlement.