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U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

o REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

OR

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

For the fiscal year ended December 31, 2007

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

Not Applicable
(Translation of Registrant's Name into English (if applicable))

Canada	**4923**	**None**
(Province or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number (if applicable))*	*(I.R.S. Employer Identification Number (if applicable))*

3000 Fifth Avenue Place
425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone Number: (403) 231-3900
(Address and telephone number of Registrant's principal executive offices)

Enbridge (U.S.) Inc.
1100 Louisiana, Suite 3200
Houston, Texas 77002
Telephone Number: (713) 650-8900
(Name, address (including zip code) and telephone number *(including area code) of agent for service in the United States*

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

Title of each class	**Name of each exchange on which registered**
Common Shares	New York Stock Exchange

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

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

ý Annual Information Form ý Audited annual financial statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

368,512,396 Common shares (as at December 31, 2007)

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

o Yes ý 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 Exchange Act during the preceding 12 months (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.

ý Yes o No

DISCLOSURE CONTROLS AND PROCEDURES

As of the end of the period covered by this report, an evaluation was carried out under the supervision of and with the participation of the Registrant's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of the Registrant's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by the Registrant in reports that it files with or submits to the Securities and Exchange Commission is recorded, processed, summarized and reported within the time periods required.

No changes were made in the Registrant's internal control over financial reporting or in other factors during the period covered by this annual report on Form 40-F that have materially affected or are reasonably likely to materially affect the Registrant's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The information provided under the heading "Management's Report on Internal Control over Financial Reporting" contained in the Management's Discussion and Analysis, filed as exhibit 99.5 to this annual report on Form 40-F, is incorporated herein by reference.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's Board of Directors has determined that Messrs. J.H. England and D.A. Leslie, members of the Audit Committee, each qualify as an audit committee financial expert (as defined in Form 40-F under the Securities Exchange Act of 1934) and are independent as defined by the New York Stock Exchange corporate governance rules applicable to foreign private issuers. The SEC has indicated that the designation of each of Messrs. England and Leslie as an audit committee financial expert does not make either an "expert" for any purpose, impose any duties, obligations or liability on either of them that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee.

CODE OF ETHICS

The Registrant has adopted a code of ethics (the "Statement on Business Conduct") that applies to all employees and officers, including its principal executive officer, principal financial officer and principal accounting officer. The Statement on Business Conduct is available at the Registrant's Internet website, www.enbridge.com and is available in print to any shareholder upon written request to the Corporate Secretary of the Registrant.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

PricewaterhouseCoopers LLP (or a predecessor firm, Price Waterhouse) ("PwC") have been the auditors of the Registrant since 1992.

The information provided under the headings "Pre-Approval Policies and Procedures" and "External Auditor Services—Fees" contained in the Annual Information Form, filed as exhibit 99.3 to this annual report on Form 40-F, is incorporated herein by reference.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements as defined by Form 40-F under the Securities Act of 1934.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided in the last paragraph under the heading "Expected Capital Expenditures" contained in the Management's Discussion and Analysis, filed as exhibit 99.5 to this annual report on Form 40-F, is incorporated herein by reference.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant is required by Canadian law to have an audit committee. The Chair of the Audit, Finance & Risk Committee is D.A. Leslie and the other members are J.H. England, R.W. Martin, G.K. Petty, C.E. Shultz and C.L. Williams.

FORWARD-LOOKING STATEMENTS

A number of statements in the documents incorporated by reference in this Form 40-F constitute "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Please refer to the last paragraph under the heading "Forward-Looking Information" in the Annual Information Form of Enbridge Inc. for the year ended December 31, 2007, dated February 20, 2008, incorporated herein and forming an integral part of this document, for a discussion of risks, uncertainties and assumptions that could cause actual results to vary from those forward-looking statements.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.

Date: February 22, 2008

By: "Signed"

ALISON T. LOVE
Vice President & Corporate Secretary

EXHIBIT INDEX

99.1	Certificates of the Chief Executive Officer and Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002*.
99.2	Certificates of the Chief Executive Officer and Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002*.
99.3	Annual Information Form of the Registrant dated February 20, 2008.
99.4	Audited financial statements of the Registrant and notes thereto for the fiscal years ended December 31, 2006 and 2007 and Auditor's Report thereon.
99.5	Management's Discussion and Analysis of the Registrant for the year ended December 31, 2007 dated February 20, 2008.
99.6	Consent of PricewaterhouseCoopers LLP, independent auditors of the Registrant.

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Exhibit 99.1

CERTIFICATIONS

I, Patrick D. Daniel, certify that:

1. I have reviewed this annual report on Form 40-F of Enbridge Inc.;

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 issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer 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 issuer, 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 issuer'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 issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (and 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 issuer'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 issuer's internal control over financial reporting.

Date: February 22, 2008

"Signed"

PATRICK D. DANIEL
President & Chief Executive Officer

Exhibit 99.1

CERTIFICATIONS

I, J. Richard Bird, certify that:

1. I have reviewed this annual report on Form 40-F of Enbridge Inc.;

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 issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer 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 issuer, 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 issuer'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 issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (and 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 issuer'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 issuer's internal control over financial reporting.

Date: February 22, 2008

"Signed"

J. RICHARD BIRD
Executive Vice President, Chief Financial Officer
& Corporate Development

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Exhibit 99.1

CERTIFICATIONS

Exhibit 99.1

CERTIFICATIONS

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Exhibit 99.2

CERTIFICATIONS

Pursuant to 18 U.S.C. Section 1350,
as Enacted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Enbridge Inc. (the "Corporation") on Form 40-F for the fiscal year ending December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Patrick D. Daniel, President & Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, this 22 day of February, 2008.

"Signed"

Patrick D. Daniel
President & Chief Executive Officer

Exhibit 99.2

CERTIFICATIONS

Pursuant to 18 U.S.C. Section 1350,
as Enacted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Enbridge Inc. (the "Corporation") on Form 40-F for the fiscal year ending December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, J. Richard Bird, Executive Vice President, Chief Financial Officer & Corporate Development of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, this 22 day of February, 2008.

"Signed"

J. Richard Bird
Executive Vice President, Chief Financial Officer & Corporate Development

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Exhibit 99.2

CERTIFICATIONS
Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Exhibit 99.2

CERTIFICATIONS
Pursuant to 18 U.S.C. Section 1350, as Enacted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Exhibit 99.3



ENBRIDGE INC.
ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2007

February 20, 2008

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GLOSSARY

Adjusted operating earnings	Earnings applicable to common shareholders adjusted for non-operating factors
AFR Committee	Audit, Finance & Risk Committee
AIF	Annual Information Form
Alliance	The Alliance System
bpd	Barrels per day
bcf/d	Billion cubic feet per day
CAPP	Canadian Association of Petroleum Producers
CITCol	CIT Colombiana S.A. – 100% owned company that provides technical and management services in connection with the operation of the OCENSA pipeline
CLH	Compañía Logística de Hidrocarburos CLH, S.A. – Enbridge has a 25% interest in this Spanish pipeline company
CSR	Corporate Social Responsibility
EEM	Enbridge Energy Management, L.L.C. – Enbridge has a 17.2% investment in EEM, which owns 100% of EEP's i-units
EEP	Enbridge Energy Partners, L.P. – the Company has a 15.1% ownership interest in EEP, which owns and operates crude oil and liquid petroleum transmission pipeline systems, natural gas gathering and related facilities and marketing assets in the U.S.
EGD	Enbridge Gas Distribution Inc. – 100% owned natural gas distribution utility serving customers in its franchise areas of Central & Eastern Ontario, including the city of Toronto and surrounding areas
EGNB	Enbridge Gas New Brunswick Inc. – 70.8% of this natural gas distribution utility is owned by Enbridge
EIF	Enbridge Income Fund – Enbridge has a 41.9% ownership interest in this publicly traded income fund
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gases
IR	Incentive Regulation (applicable to EGD)
ITS	Incentive Tolling Settlement on the Enbridge mainline system
MD&A	Management's Discussion and Analysis
mmcf	Million cubic feet
mmcf/d	Million cubic feet per day
MTNs	Medium-term notes
NEB	National Energy Board
NGLs	Natural gas liquids
OCENSA	Oleoducto Central S.A. – Colombian crude oil pipeline of which 24.7% is owned by Enbridge
OEB	Ontario Energy Board
Offshore	Enbridge Offshore Pipelines – Enbridge has interests ranging from 22% to 100% in these underwater pipelines in the Gulf of Mexico
PwC	PricewaterhouseCoopers – the Company's external auditors
SEP	System Expansion Project
U.S.	United States
Year End	December 31, 2007

PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form (AIF) for Enbridge Inc. (Enbridge or the Company) is given at or for the year ended December 31, 2007 (Year End). Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles.

Enbridge's Management's Discussion and Analysis (MD&A), dated February 20, 2008, and Enbridge's Audited Consolidated Financial Statements, dated February 20, 2008, as at and for the year ended December 31, 2007 are incorporated by reference into this AIF and can be found on SEDAR at www.sedar.com.

METRIC CONVERSION TABLE

The conversion factors set out below are approximate factors. To convert from Metric to Imperial multiply by the factor indicated. To convert from Imperial to Metric divide by the factor indicated.

Metric	Imperial	Factor
Cubic metre of liquid hydrocarbons	Barrel of liquid hydrocarbons	6.29
Cubic metre kilometre	Barrel mile	3.91
Cubic metres of natural gas	Cubic feet of natural gas	35.3145

The annual capacities noted throughout this AIF take into account estimated crude receipt and delivery patterns and ongoing pipeline maintenance and reflect achievable pipeline capacity over long periods of time.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this AIF to provide Enbridge shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids; prices of crude oil, natural gas and natural gas liquids; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; anticipated in-service dates and weather.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, exchange rates, interest rates and commodity prices, including but not limited to those risks and uncertainties discussed in this AIF and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this AIF or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

CORPORATE STRUCTURE

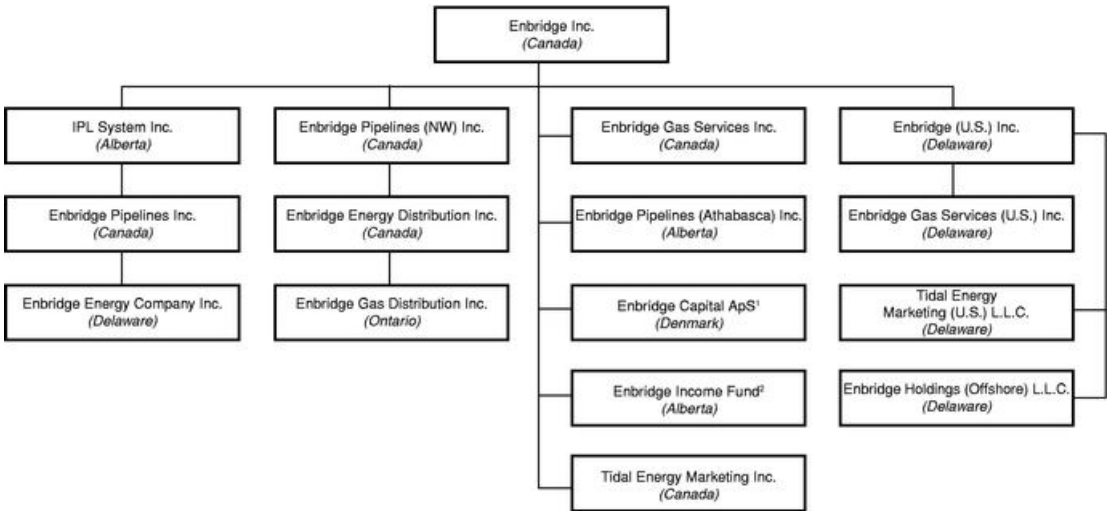
INCORPORATION

Enbridge's head office and registered office are located at 3000, 425 - 1 st Street SW, Calgary, Alberta, T2P 3L8. Enbridge is a Canadian public company. Significant dates and events are set forth below.

Date	Event
April 13, 1970	Incorporated under the Companies Act of the Northwest Territories as Gallery Holdings Ltd.
December 15, 1987	Continued under the Canada Business Corporations Act under the name 159569 Canada Ltd.
May 5, 1994	Articles of Amendment to (i) change the name to IPL Energy Inc. (French version – IPL Energie Inc.); and (ii) change the registered office to Calgary, Alberta.
October 7, 1998	Articles of Amendment to change the name of the Company to Enbridge Inc.
April 29, 1999	Articles of Amendment to (i) divide each issued and outstanding common share on a two for one basis; and (ii) provide the Board of Directors with a process to add directors between meetings of the shareholders.
May 5, 2005	Articles of Amendment to divide each issued and outstanding common share on a two for one basis.

SUBSIDIARIES

The following organization chart presents the name and the jurisdiction of incorporation of Enbridge's material subsidiaries as at December 31, 2007. Unless otherwise noted, each subsidiary listed below is 100% owned by the Company. Each of these subsidiaries had total assets that exceeded 10% of the total consolidated assets of Enbridge or revenues that exceeded 10% of the total consolidated revenues of Enbridge as at and for the year ended December 31, 2007.



Notes:

1 *Enbridge Capital ApS owns the Company's 25% investment in Compañía Logística de Hidrocarburos CLH, S.A. (CLH.)*

2 *The Company owns 41.9% of Enbridge Income Fund (EIF) and is the primary beneficiary of EIF through a combination of voting interest and an investment in preferred units of an EIF subsidiary and, as such, EIF is consolidated under Variable Interest Entity accounting rules.*

The chart above does not include all of the subsidiaries of Enbridge. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20% of the total consolidated assets or total consolidated revenues of Enbridge as at and for the year ended December 31, 2007.

DESCRIPTION OF THE BUSINESS

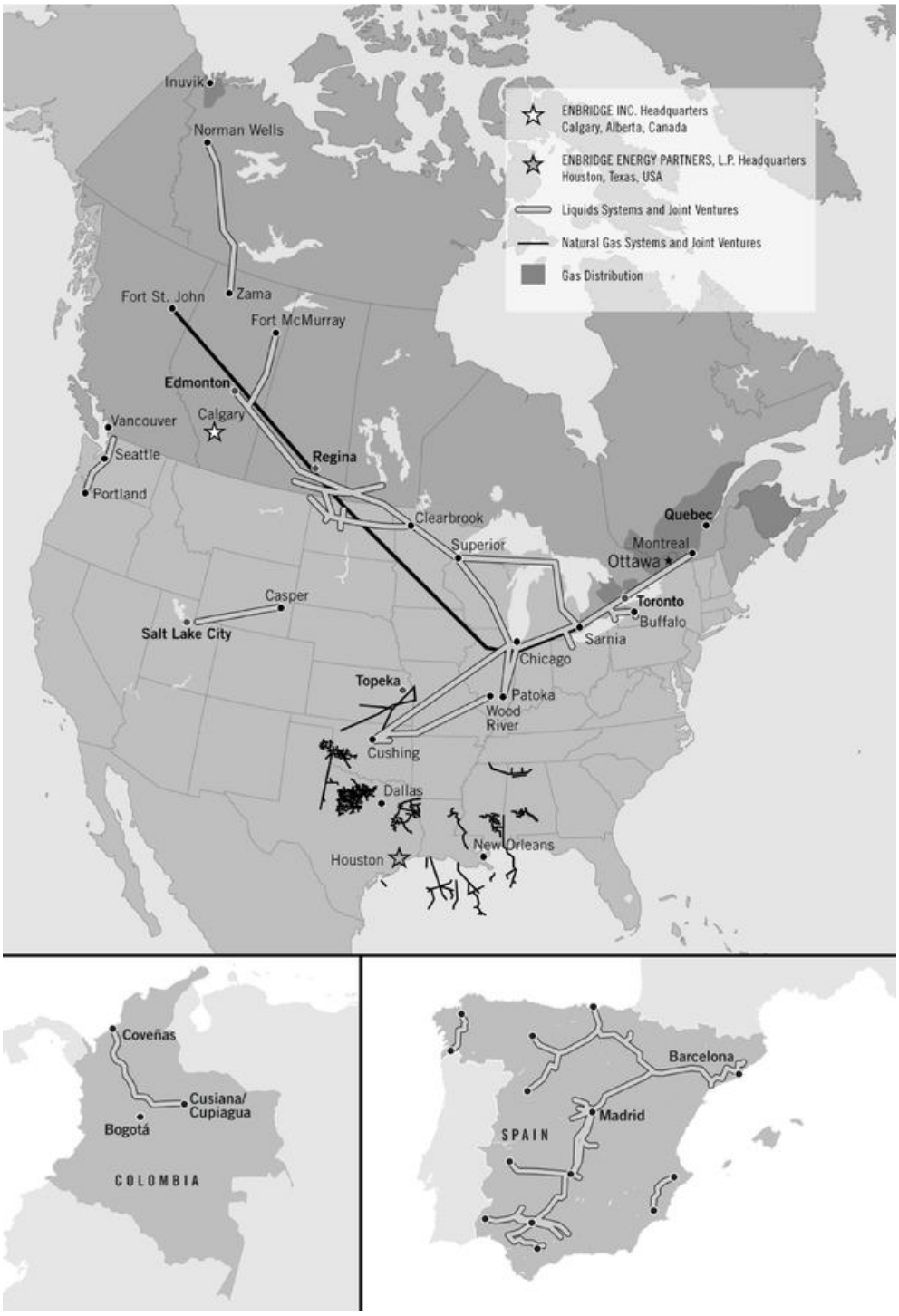
Enbridge's primary business activities are the transportation and distribution of crude oil and natural gas. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Pipelines, Gas Distribution and Services, Sponsored Investments and International.

- Liquids Pipelines includes the operation of the petroleum mainline system and feeder pipelines that transport crude oil and natural gas liquids (NGLs) in Canada and the United States (U.S.).
- Gas Pipelines represents Enbridge's interest in natural gas transmission and gathering systems.
- Gas Distribution and Services consists primarily of natural gas utility operations that serve residential, commercial, industrial and transportation customers in Central and Eastern Ontario. It also includes the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing businesses.
- Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP) and Enbridge Income Fund.
- The Company's International business consists of investments in energy delivery businesses, Compañía Logística de Hidrocarburos CLH, S.A. in Spain and Oleoducto Central S.A. (OCENSA) in Colombia.

Each business segment's contribution to earnings and revenues is as follows:

	2007		2006		2005	
	Revenue	**Earnings**	**Revenue**	**Earnings**	**Revenue**	**Earnings**
Liquids Pipelines	9.2%	41.0%	9.8%	44.6%	10.4%	41.1%
Gas Pipelines	2.7%	10.0%	3.3%	9.9%	4.3%	10.8%
Gas Distribution and Services	85.7%	26.3%	84.4%	29.0%	82.2%	32.2%
Sponsored Investments	2.3%	13.8%	2.4%	14.1%	3.0%	11.7%
International	0.1%	13.6%	0.1%	13.5%	0.1%	15.7%
Corporate	–	(4.7)%	–	(11.1)%	–	(11.5)%

The following map includes the Company's operations:



GENERAL DEVELOPMENT OF THE BUSINESS

Enbridge's 2007 Strategic Plan includes three corporate strategies that support the Company's vision of becoming North America's leading energy delivery company and its ability to deliver superior shareholder value. The corporate strategies are to (1) expand existing core businesses; (2) focus on operational excellence, people and the environment; and (3) develop new platforms for growth and diversification. The first strategy will be achieved primarily through organic based growth within the Company's core businesses and the third strategy includes making investments that are closely aligned with and support the core businesses.

The last three years have seen increasing development and production from the Canadian oil sands and increasing demand for Canadian crude oil in the U.S. Historically, Canada has been the third largest supplier of crude oil to the U.S.; however, for the past four years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S. The growth in supply from Canada comes primarily from the Canadian oil sands. The Company has responded to these changing supply and demand fundamentals by proposing a number of new liquids pipelines and expansions to existing pipelines delivering crude oil from Canada to the United States.

In response to shipper demand, the Company is constructing or expanding a number of regional oil sands pipelines including the Waupisoo Pipeline, which is expected to begin shipping crude oil to Edmonton, Alberta in mid-2008, and the Fort Hills Pipeline, which is in the planning stage and is expected to link the Fort Hills Project North of Fort McMurray, Alberta with the upgrader site Northeast of Edmonton in mid-2011.

Enbridge is also expanding its mainline capacity between Edmonton and the Chicago, Illinois area. The Southern Access Expansion is expected to add a total of 400,000 barrels per day (bpd) incremental capacity including the U.S. portion of this project being undertaken by the Company's affiliate, EEP. In the United States, the expansion will be completed in stages, finishing in 2009. Currently, construction activities are underway on the 321-mile (517-kilometre) section from Superior to Delavan, Wisconsin with over 94% of welding completed. This first stage of construction of the U.S. portion of this expansion is on schedule for completion in the second quarter of 2008 and will add capacity of approximately 190,000 bpd. The Alberta Clipper Project is expected to add an additional 450,000 bpd to the mainline capacity in mid-2010.

The Company's Southern Lights Pipeline will transport diluent from Chicago, Illinois to Edmonton, Alberta. This diluent supply is required as a result of the increasing heavy oil production in Alberta. Southern Lights is expected to be in service in late-2010. The Gateway Project, in the planning stage, includes both a condensate import pipeline and a petroleum export pipeline. The condensate line, with an initial capacity of 193,000 bpd, would transport diluent to the Edmonton area from Kitimat, British Columbia. The 36-inch diameter petroleum export line would have an initial capacity of 525,000 bpd and would transport crude oil from the Edmonton area to Kitimat.

Expanding market access for Canadian crude oil is another key component of the Company's strategy. Access to a number of different markets allows shippers to obtain the best price for their crude oil. One example is the Southern Access Extension Project, which would extend the mainline from Flanagan to Patoka, Illinois.

Also, the proposed Texas Access Pipeline will transport crude oil sourced from the Canadian oil sands region in Alberta and from the upper U.S. Midwest to the Texas Gulf Coast. The proposed project includes a new 1,236-kilometre (768-mile) pipeline with a capacity of approximately 450,000 bpd which will extend from Patoka, Illinois southward to Nederland, Texas. Also proposed is a 142-kilometre (88-mile) pipeline with a capacity of approximately 180,000 bpd to transport crude oil onward from Nederland to the Houston, Texas area.

As a result of interest by producers in contract terminals, the Company is increasing its investment in tankage projects. These projects include upstream terminals at or near Hardisty and Fort Saskatchewan, Alberta and downstream terminals at Flanagan, Illinois, Patoka, Illinois and Cushing, Oklahoma. As well, significant additions to the capacity of the common carrier mainline terminals at Edmonton, Alberta, Superior, Wisconsin and the Chicago, Illinois area are underway.

The Company's MD&A for the year ended December 31, 2007 includes further details on each of these projects as well as other projects Enbridge is currently undertaking.

The business environment of Enbridge Gas Distribution (EGD), the primary component of the Gas Distribution and Services segment, is affected by the regulatory framework in Ontario, weather, the demand for natural gas and residential customer growth. Since 2003, EGD's rates have been based on a cost of service methodology under which rates are set to recover costs incurred plus an approved return on equity. In 2006, the Ontario Energy Board (OEB) announced its

intention to regulate natural gas distribution utilities under an incentive regulation (IR) mechanism starting in 2008 for a multi-year term. Under this framework, rate-regulated companies have the opportunity to improve their returns through productivity improvements and revenue growth. EGD filed its 2008 rate application under IR in August 2007 and its Settlement Agreement filed with the OEB on January 28, 2008 was approved on February 11, 2008. Although demand for natural gas continues to decline as customers adopt energy efficient technologies, declining demand is offset by growth in residential customers. EGD continues to add 40,000 to 50,000 new customers each year and these trends are expected to continue. Further details on IR can be found under the sub-heading "Incentive Regulation" in the Gas Distribution and Services section of the AIF.

On February 4, 2008, the Company announced that it will lead a group of 19 energy industry participants in the Alberta Saline Aquifer Project (ASAP). ASAP is a broad-based, industry-supported initiative that will be rolled out in three phases. This project will play a major role in advancing industry and government's knowledge of carbon dioxide sequestration.

On February 13, 2008, the Company announced that it has engaged a third party to assist it in evaluating strategic alternatives for monetizing its investment in CLH. These alternatives include the potential sale of some or all of Enbridge's 25% interest in the company, but there is no assurance the evaluation will result in any specific transaction, or if a transaction does occur, the timing of such a transaction.

LIQUIDS PIPELINES

Liquids Pipelines consists of crude oil, NGLs and refined products pipelines in Canada and the U.S. This business segment includes the Enbridge System, Athabasca System, Olympic Pipeline, Spearhead Pipeline and interests in various feeder pipelines.

ENBRIDGE SYSTEM

The mainline system is comprised of the Enbridge System and the Lakehead System (the portion of the mainline in the U.S. that is owned by EEP and operated by Enbridge). The Enbridge System transports up to 83 different types of liquid hydrocarbons including light, medium and heavy crude oil (including diluted bitumen), condensate, synthetic crudes, NGLs and refined products from Western Canada to the Midwest region of the U.S. and Eastern Canada and serves all major refining centres in Ontario. Shipments delivered to the Enbridge System originate in conventional oilfields and oil sands in Alberta, Saskatchewan, Manitoba, British Columbia and the Northwest Territories. These pipelines connect with the Enbridge System at two receiving points in Alberta, two in Saskatchewan and one in Manitoba. In addition, the Enbridge System receives offshore crude oil through connecting pipelines at Montréal, Québec.

The Enbridge System consists of the following segments, with the total length of pipeline right-of-way being approximately 2,300 kilometres (1,429 miles):

- Mainline segment that consists of five adjacent pipelines, with a capacity of approximately 2.0 million bpd from Edmonton, Alberta to the U.S. border near Gretna, Manitoba.
- Sarnia to Toronto, Ontario segment with a capacity of 150,000 bpd. This segment includes lateral lines from Westover to Nanticoke and Niagara Falls, Ontario.
- Line 9 segment from Montreal, Quebec to Sarnia, Ontario with a capacity of 240,000 bpd.

The following table sets forth the information related to deliveries and other distance-related operating data of the Enbridge System for each of the years in the three-year period ended December 31, 2007.

(thousands of barrels per day)	2007	2006	2005
Prairie Provinces			
Light crude oil	173	190	182
Medium and heavy crude oil	142	138	132
Refined products	81	79	79
	396	407	393
United States			
Light crude oil	282	276	198
Medium and heavy crude oil	852	871	783
Refined products	4	4	4
	1,138	1,151	985
Ontario[1]			
Light crude oil	314	302	338
Medium and heavy crude oil	62	63	58
Refined products	95	90	98
	471	455	494
Total Deliveries	2,005	2,013	1,872
Barrel Miles *(billions)*	391	388	350
Average Haul *(miles)*	534	529	513

Note:

1 Enbridge System average deliveries include Line 9 volumes of 130,000 bpd (2006 – 141,000 bpd; 2005 – 190,000 bpd).

Incentive Tolling

Tolls on the Enbridge System are governed by various agreements, which are subject to the approval of the National Energy Board (NEB). The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and ratemaking agreements and other contractual arrangements with customers. Significant agreements include the Incentive Tolling Settlement (ITS) applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace Agreement and the System Expansion Program (SEP) II Risk Sharing Agreement.

Tolls on the core mainline system have been governed by incentive tolling settlements since 1995. The main objective of this methodology is to more closely align the interests of the Company with the interests of its shippers. The ITS allows the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. The Company has the opportunity to increase earnings by achieving performance targets under performance metric provisions and may incur penalties if performance falls short of specified thresholds. In conjunction with the Terrace Agreement, the ITS continues the throughput protection provisions included in earlier incentive tolling arrangements, ensuring the Company is insulated from volume fluctuations beyond its control. The current ITS expires at the end of 2009. The surcharge under the Terrace Agreement expires in 2013.

Under published tariffs for the Enbridge System, the tolls for transportation, including terminaling charges where applicable, of light crude oil from Edmonton to principal delivery points, at December 31, 2007 are set forth below.

Delivery Point	Canadian Toll per Barrel
Regina, Saskatchewan	$0.8347
U.S. border near Gretna, Manitoba	$1.1953
Sarnia, Ontario	$1.3069

To compensate for differences in costs for shipping different types and grades of liquid hydrocarbons, the rates for medium and heavy crude oils are higher, while those for refined products and NGLs are lower than the rates set forth in the above table. The Canadian portion of the Terrace Agreement toll surcharge, described below, is included in the tolls listed in the table above.

Terrace Agreement

As part of the Terrace Agreement, Enbridge, EEP and the Canadian Association of Petroleum Producers (CAPP) agreed to a fixed toll surcharge of $0.05 per barrel for the movement of light crude from Edmonton to the Chicago area. This toll surcharge commenced on April 1, 1999, when Terrace Phase I was completed. The incremental toll is allocated between Enbridge and EEP. Revenue related to unused capacity in Canada under the Terrace Agreement is incorporated in tolls in the following year.

SEP II Risk Sharing Agreement

Enbridge, EEP and CAPP entered into a Risk Sharing Agreement, effective for 15 years, with respect to SEP II, a 100,000 bpd expansion completed in 1998. The Risk Sharing Agreement provides that the rate of return on the SEP II investment will be based, in part, on the utilization level of the additional capacity constructed. Higher utilization is expected to result in a greater return, subject to a minimum and maximum rate of return of 7.5% and 15.0%, respectively. During 2007, Enbridge and EEP earned a rate of return of 11.46% (2006 – 7.5%) on SEP II.

OTHER LIQUIDS PIPELINES AND SYSTEMS

Athabasca System

The Athabasca System, a 540-kilometre (340-mile) synthetic and heavy oil pipeline, links the Athabasca oil sands in the Fort McMurray, Alberta region to a pipeline transportation hub at Hardisty, Alberta. The system has a design capacity of approximately 570,000 bpd; however, it is currently configured to transport 390,000 bpd. The Athabasca System includes the MacKay River, Christina Lake, Surmont and Long Lake facilities, contract tankage facilities and the Company's interest in the Hardisty Caverns Limited Partnership which provides crude oil tankage services. Enbridge has a 30-year take-or-pay contract with the major shipper on the Athabasca System, which commenced in 1999. The agreement also provides the shipper with options to increase and extend the life of the agreement beyond the initial 30-year term. The Athabasca System is regulated by the Energy Resources Conservation Board (ERCB) in Alberta.

Spearhead Pipeline

The Spearhead Pipeline, which went into service in March 2006, has a capacity of 125,000 bpd and extends approximately 1,058 kilometres (657 miles) from Chicago, Illinois to Cushing, Oklahoma. The Company has ten-year shipper commitments for 108,000 bpd. The Spearhead Pipeline is regulated by the Federal Energy Regulatory Commission (FERC).

Olympic Pipeline

In February 2006, Enbridge acquired a 65% interest in the Olympic Pipeline, which is the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. The pipeline system extends approximately 480 kilometres (300 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland. BP Pipelines (North America) Inc. is the operator of the pipeline system.

COMPETITIVE CONDITIONS

Competition among common carrier pipelines is based primarily upon the cost of transportation, access to supply, the quality and reliability of service and contract carrier alternatives and proximity to markets. Other common carriers are available to producers to ship Western Canadian liquid hydrocarbons to markets in either Canada or the U.S. Competition could also arise from pipeline proposals that may provide access to market areas currently served by the Company's liquids pipelines. The Company believes its liquids pipelines are serving larger markets and provide attractive options to producers in the Western Canadian Sedimentary Basin (WCSB) due to their competitive tolls and multiple delivery and storage points. Also, shippers are not required to enter into long-term shipping commitments on Enbridge's mainline system. The Company's existing right-of-way provides a competitive advantage as it can be difficult and costly to obtain new rights of way for new pipelines.

GAS PIPELINES

Gas Pipelines activities consist of investments in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines (Offshore). Enbridge has joint control over these investments with one or more other owners. Enbridge owns a 50% interest in the U.S. portion of the Alliance System, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising Offshore.

ALLIANCE PIPELINE

The Alliance System (Alliance), which includes both the Canadian and U.S. portions of the pipeline system, consists of an approximately 3,000-kilometre (1,875-miles) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (455-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from Northeast British Columbia and Northwest Alberta to Channahon, Illinois. EIF, which is included in the Sponsored Investments business segment, owns 50% of the Canadian portion of the Alliance System.

Alliance connects with Aux Sable, a NGLs extraction facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the Midwestern and Northeastern U.S. and Eastern Canada. Enbridge owns 42.7% of Aux Sable which is included in the Gas Distribution and Services business segment.

Alliance has long-term take-or-pay contracts through 2015 to transport 1.305 billion cubic feet per day (bcf/d) of natural gas or 98.5% of the total contracted capacity. Alliance has an additional 20 million cubic feet per day (mmcf/d) of natural gas contracted through 2010. Additional transportation capacity of approximately 0.3 bcf/d is available to shippers at only the cost of the associated fuel requirements. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed return on equity. Each long-term contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. Alliance Pipeline US operations are regulated by the FERC.

VECTOR PIPELINE

Enbridge provides operating services to and holds a 60% joint venture interest in Vector Pipeline. The 560-kilometre (348-mile) pipeline transports natural gas from Chicago, Illinois to Dawn, Ontario. The primary sources of supply are through interconnections with the Alliance System and the Northern Border Pipeline in Joliet, Illinois.

Vector Pipeline has a nominal delivery capacity of 1.2 bcf/d, which is expandable to 1.5 bcf/d with additional compression stations, and is operating at or near capacity. Approximately 58% of the long haul capacity of Vector is committed to long-term firm transportation contracts until 2015 at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and at various term lengths.

ENBRIDGE OFFSHORE PIPELINES

Offshore is comprised of 11 natural gas gathering and FERC-regulated transmission pipelines in five major corridors in the Gulf of Mexico, extending to deepwater frontiers. These pipelines include almost 2,400 kilometres (1,500 miles) of underwater pipe and onshore facilities and transported approximately 2.1 bcf/d during 2007.

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The throughput volume generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria but also provide the shippers with flexibility given advance notice criteria to modify the projected MDQ schedule to match current deliverability expectations.

The long-term transport rates established in the gathering and transmission service agreements are generally market-based but are established using a cost of service methodology, which includes operating cost, projected revenue generation directly tied to production deliverability and the appropriate cost of capital.

COMPETITIVE CONDITIONS

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB to distribution systems in the Midwestern U.S. In addition, there are several proposals to upgrade existing pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by the Alliance System.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new or upgraded pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors.

There is significant competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities and extend its footprint, positioning it to more fully utilize existing capacity. Offshore serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has Offshore well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. However, given rates of decline, offshore pipelines typically have available capacity resulting in significant and aggressive competition for new developments in the Gulf of Mexico.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in Central and Eastern Ontario, the most significant being EGD. This segment also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing business.

ENBRIDGE GAS DISTRIBUTION

EGD is a rate-regulated natural gas distribution utility serving over 1.8 million customers in Central and Eastern Ontario, Southwestern Quebec and parts of Northern New York State. EGD's operations in Ontario are regulated by the Ontario Energy Board. EGD operates in a seasonal industry and earnings vary significantly according to weather patterns. Periods of colder weather would normally result in higher earnings compared to periods of warmer weather.

There are four principal interrelated aspects of the natural gas distribution business in which EGD is directly involved: Distribution Service, Gas Supply, Transportation and Storage.

Distribution Service

EGD's principal source of revenue is from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis (without a specific fixed term or fixed price contract). The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts. Under a firm contract, EGD is obligated to deliver natural gas to the customer up to a maximum daily volume. The service provided under an interruptible contract is similar to that of a firm contract, except that it allows for service interruption at EGD's option to meet seasonal or peak demands. The OEB approves rates for both contract and general services.

Gas Supply

To acquire the necessary volume of gas to service its customers, EGD maintains a diversified gas supply portfolio. During the year ended December 31, 2007, EGD acquired approximately 184.9 bcf (2006 – 156.9 bcf) of natural gas, of which 21.6% (2006 – 23.8%) was acquired from Western Canadian producers, 47.3% (2006 – 53.8%) was acquired from suppliers in Chicago and 31.1% (2006 – 22.4%) was acquired on a delivered basis in Ontario. EGD also transported 250.6 bcf (2006 – 257.8 bcf) of natural gas on behalf of direct purchase customers operating under a transportation service arrangement.

EGD's system supply gas contracts have pricing structures responsive to supply and demand conditions in the North American natural gas market. The prices in these contracts are indexed to either Alberta, Chicago or New York based prices.

Transportation

EGD relies primarily upon TransCanada PipeLines Limited (TransCanada) for transportation service to bring its diversified gas supply from Western Canada to its franchise area. EGD has long-term firm transportation service contracts with TransCanada, over varying time periods, for annual deliveries of approximately 264.7 bcf of natural gas. This amount includes deliveries by direct purchase customers via TransCanada capacity that has been assigned by EGD to the direct purchase customer or capacity that has been contracted directly with TransCanada by the direct purchase customer.

The transportation service contracts are not directly linked with any particular source of gas supply. Separating transportation contracts from gas supply allows EGD flexibility in obtaining its own gas supply and accommodating the transportation of gas purchased directly by end-use customers. EGD continues to forecast the gas supply needs of all its customers including the associated transportation and storage requirements.

TransCanada's transportation tolls, which are approved by the NEB, consist of a demand component (to recover fixed costs) and a commodity component (to recover variable costs) for Firm Transportation (FT) service. A FT shipper (such as EGD) must pay the demand component regardless of the volume of gas that TransCanada actually transports for the FT shipper. Consequently, if a FT shipper does not utilize all of its FT capacity rights, the FT shipper would incur unabsorbed demand charges in respect of the unutilized portion. EGD also has contracts for Firm Transportation service on the Alliance System and Vector Pipeline.

EGD relies on its long-term contracts with Union Gas Limited (Union) for transportation of gas from Dawn, Ontario to EGD's major market in the Greater Toronto Area. The contracts effectively provide EGD with access to U.S. sourced gas at Dawn by the Vector Pipeline. The contracts also provide transportation for gas stored at EGD's and Union's storage pools in the Sarnia, Ontario area to the market area.

EGD was also a participant in the Link Project, which involved the construction of connecting pipelines in Southwestern Ontario by Niagara Gas Transmission Limited, a wholly-owned subsidiary of Enbridge, and in Southwestern Michigan by ANR Pipeline Company (ANR). These pipelines link ANR's Southeast and Southwest mainlines, which access major U.S. supply basins, and Michigan Consolidated Gas Company's (MichCon) transportation system, which accesses Michigan supplies, directly to EGD's principal storage facilities near Dawn (see "Storage" below) and indirectly to Union's transmission system at Dawn. EGD has entered into long-term contracts for transportation service with both ANR and MichCon.

Storage

The business of EGD is highly seasonal as daily market demand for gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits EGD to take delivery of gas on favourable terms during off-peak summer periods for subsequent use during the winter heating season. This practice permits EGD to minimize the annual cost of transportation of gas from Western Canada, assists in reducing its overall cost of gas supply and adds a measure of security in the event of short-term interruption of transportation of gas from Western Canada to EGD's franchise area.

EGD's principal storage facilities are located in Southwestern Ontario, near Dawn, and have a total working capacity of approximately 95.3 bcf. Approximately 91.8 bcf of the total working capacity are available to EGD. EGD also has storage contracts with Union for 19.4 bcf of storage capacity, with terms varying from two to four years.

EGD operated storage facilities are connected to the Dawn storage and transmission hub by two 30-inch pipelines owned by EGD. In the summer, gas is delivered to Dawn for injection into storage through the transmission facilities of TransCanada and Vector Pipeline. In the winter, gas is withdrawn from storage and delivered to Dawn and transported from there to EGD's major market area of Toronto through the transmission facilities of Union. EGD has transportation contracts with TransCanada, Vector Pipeline and Union for the delivery of gas to and from storage.

Historical Operating Statistics

The following tables present certain statistics relating to the past three years of operations of EGD:

	2007	2006	2005
Gas supply and send out *(million cubic feet (mmcf))*			
Natural gas purchased	184,850	156,850	183,333
Gas into storage	(102,327)	(75,224)	(105,097)
Gas out of storage	104,955	74,602	96,381
Total gas sendout	187,478	156,228	174,617
Transportation of gas	255,635	250,445	264,034
	443,113	406,673	438,651
Gas sales to customers *(mmcf)*	179,899	159,503	174,515
Transportation of gas	259,830	248,389	264,182
Total sales	439,729	407,892	438,697
Used by EGD	120	141	170
Other volumetric variations	3,264	(1,360)	(216)
	443,113	406,673	438,651
Average daily sendout *(mmcf)*	1,215	1,109	1,194
Average use per residential customer *(thousand cubic feet)*	99	93	104
Degree day deficiency[1]			
Actual	3,659	3,355	3,750
Forecast based on normal weather	3,617	3,745	3,747
Number of active customers at year end[2]			
Residential	1,062,008	1,007,058	1,047,350
Commercial	97,988	92,053	93,686
Industrial	3,732	3,549	3,763
Wholesale	1	1	1
Transportation	697,128	717,104	629,267
	1,860,857	1,819,765	1,774,067
New customer additions[3]	43,160	47,622	50,697

Notes:

1 *Degree day deficiency is a measure of coldness which is indicative of volumetric requirements of natural gas utilized for heating purposes in EGD's franchise area. It is calculated by accumulating, for the fiscal 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.*

2 *Active customers relate to the count of gas-consuming customers at the end of the period and include gas sales and transportation service customers. As the commodity cost of gas is flowed through to gas sales customers with no mark up, the composition of customers between gas sales and transportation service has no material impact on EGD's earnings.*

3 *New customer additions relate to new service lines installed during the period.*

Incentive Regulation

EGD remained in a cost of service methodology environment in 2007, but will change to Incentive Regulation methodology in 2008 with 2007 as the base year for a potential five year plan. Under IR, rates are set based on a formulaic approach, using the base year rates as the starting point for the IR plan term.

The objectives of the IR plan are as follows:

- reduce regulatory costs with less frequent hearings – under normal circumstances, every five years – rather than every year under cost of service;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

Rate Application for the IR Term Starting 2008

On February 11, 2008, the OEB approved the Settlement Agreement (the Settlement) filed by EGD which reflected negotiations with ratepayer

representatives regarding the type of IR methodology as well as the applicable terms and

conditions. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive).

EGD's rate application requested a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The application also requested that revenue per customer be calculated by increasing the prior year's revenue by inflation and reducing it by a productivity challenge factor which would motivate EGD to increase productivity. Revenue could also include specific categories of expenses to enable EGD to recover cost increases beyond management's control.

This IR methodology adjusts revenues every year, not rates, and relies on an annual process to forecast volume and customer additions. Unlike the cost of service methodology used in prior years, the concepts of rate base and return on rate base are not relevant for the purpose of setting rates. Under IR, EGD will have the opportunity to benefit from productivity enhancements and incremental revenues.

The key terms of the Settlement are summarized as follows:

Revenue per Customer Cap – The Settlement allows for the annual reset of volumes, with revenues increasing proportionately with the growth in the number of customers. The revenue per customer cap will continue to minimize EGD's exposure to declining average use of natural gas while providing incentive for EGD to continue growing its customer base.

Earnings Sharing – To align the interests of customers with EGD, an earnings sharing mechanism forms part of the Settlement. To the extent the actual utility return on equity represented by normalized earnings (i.e. excluding the effects of weather) (ROE) exceeds a notional allowed utility rate of return on equity (NROE) by certain prescribed thresholds, the excess will be shared with customers.

Adjustments – The Settlement provides for the recovery of capital invested in new power generation laterals. EGD is also allowed to recover expenses above a defined threshold, to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

Off Ramps – An OEB review will be triggered if EGD's ROE varies more than 300 basis points (either negatively or positively) relative to the NROE.

EGD applied for and, on December 18, 2007, was granted approval for interim rates effective January 1, 2008 and expects the OEB's final 2008 rate order will be applied retroactively to January 1, 2008.

2007 and 2006 Rates

The key elements of the 2007 and 2006 OEB decisions are summarized below:

Approved for	**2007**	**2006**
Rate base *(millions)*	$3,745.7	$3,633.6
Deemed common equity for regulatory purposes	36.00%	35.00%
Rate of return on common equity	8.39%	8.74%

The OEB released its final decision relating to EGD's 2007 cost of service rate application on July 5, 2007. The new rates approved by the OEB's decision resulted in an overall increase in rates of approximately 3.5% for the average residential customer. EGD was granted a 1% increase in the equity component of its deemed capital structure to 36% from 35% reflecting changes in EGD's business risk environment and financial risk position. In addition, a new 20-year trend method to calculate normal weather was approved. Finally, EGD was directed to cease its risk management program, which utilized price swaps, calls and collars to manage the volatility in the price of natural gas. Consistent with the prior year, changes in the price of natural gas flow through to the customer.

Competitive Conditions

Natural gas is the predominant fuel of choice in the residential heating market throughout EGD's franchise area. The primary competition for natural gas remains domestic fuel oil and electricity. Natural gas has continued to provide both environmental and price advantages, and this is expected to continue. During 2007, natural gas in the residential market experienced, on average, a price advantage on an equivalent annual volume basis of 43% (2006 – 38%) against electricity and 41% (2006 – 30%) against domestic fuel oil.

The Ontario franchise area remains one of the most rapidly growing regions in North America. While customer growth results in increased distribution volumes, it is partially offset by declining average annual consumption, resulting from energy efficiencies achieved through new technologies and building construction. In addition, conservation efforts by customers to partially mitigate the impact of higher natural gas commodity prices further contribute to the decline in annual average consumption.

OTHER GAS DISTRIBUTION AND SERVICES BUSINESSES

Enbridge owns an equity interest in Noverco through ownership of 32.1% of the common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71.0% of Gaz Metro Limited Partnership (Gaz Metro), a gas distribution company operating in the province of Quebec and the state of Vermont. Gaz Metro also has a 50% interest in TQM Pipeline, which transports natural gas in Quebec.

The Company owns 70.8% of, and operates, Enbridge Gas New Brunswick (EGNB), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 8,200 customers. Approximately 645 kilometres (400 miles) of distribution main has been installed with the capability of attaching 29,000 customers. EGNB is regulated by the New Brunswick Energy and Utilities Board.

Enbridge also owns 42.7% of Aux Sable, a NGLs extraction and fractionation business near Chicago. Aux Sable owns and operates a plant at the terminus of the Alliance System. The plant extracts NGLs from the energy-rich natural gas transported on the Alliance System, as necessary, to meet the heat content requirements of local distribution companies, which require natural gas with less NGLs, or lower heat content, and to take advantage of positive commodity price spreads. Aux Sable has an agreement with BP Products (North America) Inc. (BP) to sell its NGLs production to BP. In return, BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and is responsible for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement is for an initial term of 20 years, commencing January 1, 2006 and may be extended by mutual agreement for 10-year terms. If cumulative losses exceed a certain limit, BP will have the option to terminate the agreement, although Aux Sable has the right to reduce such losses to avoid termination.

Tidal Energy provides crude oil and NGLs marketing services for the Company and its customers in a full range of condensate and crude oil types including light sweet, light and medium sours and several heavy grades. Tidal Energy transacts at many of the major North American market hubs and provides its customers with a variety of programs including flexible pricing arrangements, hedging programs, product exchanges, physical storage programs and total supply management, through the analysis and implementation of different transportation options, reduced quality differentials and tariff structures, and utilizing risk management pricing options. Tidal Energy's business involves buying, selling and storing large quantities of crude oil. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities, physical receipt or delivery shortfalls can create modest commodity exposures. Any open positions created from this physical business are tightly monitored by, and must comply with, the Company's formal risk management policies.

Gas Services markets natural gas to optimize Enbridge's commitments on the Alliance and Vector Pipelines. It also has a growing business of providing fee-for-service arrangements for third parties, leveraging its marketing expertise and access to transportation capacity. Capacity commitments as of December 31, 2007 were 32.2 mmcf/d (2006 – 31.6 mmcf/d) on the Alliance Pipeline (2.0% of total capacity) and 162.1 mmcf/d (2006 – 159.2 mmcf/d) on Vector Pipeline (16.4% of total capacity).

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 15.1% ownership interest in EEP and a 41.9% voting interest in EIF. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each, including both organic growth and acquisition opportunities.

ENBRIDGE ENERGY PARTNERS

Enbridge's 15.1% ownership in EEP is through a 2.0% general partner interest, a 4.2% interest in Class B units, a 6.4% interest in Class C units and a 2.5% interest in EEP via a 17.2% investment in EEM, which owns 14.6% of EEP via its 100% interest in EEP's i-units.

EEP owns and operates crude oil and liquid petroleum transmission pipeline systems, natural gas gathering and related facilities and natural gas marketing assets in the U.S. Significant assets include the Lakehead System, which is the extension of the Enbridge System in the U.S., natural gas gathering and processing assets in Texas, the mid-continent crude oil system, various interstate and intrastate natural gas pipelines and a crude oil feeder pipeline in North Dakota.

ENBRIDGE INCOME FUND

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and a 100% interest in the Enbridge Saskatchewan System. Enbridge's 41.9% interest in EIF is in the form of subordinated units of EIF and 100% of the non-voting, preferred units of Enbridge Commercial Trust, a direct subsidiary of EIF.

Alliance Pipeline Canada, which consists of an approximately 1,560-kilometre (969-mile) high-pressure, natural gas transmission system and an approximately 700-kilometre (435-mile) lateral pipeline system, is the Canadian portion of the Alliance System discussed in the Gas Pipelines segment. The Enbridge Saskatchewan System owns and operates pipeline systems that transport crude oil and liquids from producing fields in Southern Saskatchewan and Southwestern Manitoba connecting primarily with Enbridge's mainline pipeline to the U.S.

EIF also owns interests in three wind power generation projects purchased from Enbridge in October 2006 and a business that develops and operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

Tax Fairness Plan

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax of 29.5% will be imposed on Enbridge Income Fund starting in 2011, provided EIF limits its expansion to "normal growth" prior to 2011. The immediate impact of the Tax Fairness Plan on the Fund's reported earnings was relatively small because most of the assets are rate regulated and future taxes are expected to be included in the approved rates charged to customers in the future. However, as enacted in its present form, the Tax Fairness Plan will, all other things being equal, likely result in a reduction of cash available for distribution by EIF commencing in 2011. With respect to the limitations on normal growth, the Company believes that the Fund should be able to fund its currently identified growth plans within the constraints of the "normal growth" rule.

INTERNATIONAL

The International segment supplements North American business activities and diversifies the Company's sources of earnings by securing participation in energy transportation and related energy projects outside of Canada and the U.S. The Company has a 25% interest in Compañía Logística de Hidrocarburos CLH, S.A., Spain's largest refined products transportation and storage business, a 24.7% investment in a Colombian crude oil pipeline, Oleoducto Central S.A. and a 100% interest in CIT Colombiana S.A. (CITCol), which provides technical and management services in connection with the operation of the OCENSA pipeline.

COMPAÑÍA LOGÍSTICA DE HIDROCARBUROS CLH, S.A.

The primary activity of CLH is the storage and shipment of refined products through a comprehensive distribution network located throughout Spain. Earnings are based on a fee for service tariff, adjusted annually for inflation, and are dependent on throughput volumes and storage levels.

CLH is the primary basic logistics distribution network for refined products in Spain and provides services on an open access, non-discriminatory basis. The system consists of over 3,400 kilometres (2,113 miles) of pipelines and 38 storage facilities located throughout the country. CLH's pipeline facilities are connected to the country's eight crude oil refineries and to major coastal port locations where most imports of crude oil and refined products into Spain are first delivered. CLH receives refined products from customers at the refineries or ports and transports them, mainly by pipeline, to its storage facilities located throughout the Spanish mainland and the Balearic Islands. The network of pipelines and storage facilities are the primary means by which the Spanish refiners and other market players supply their commercial and retail customers. CLH customers' product destinations are located, on average, less than 60 kilometres (37 miles) via highway from a CLH terminal. CLH provides refined product distribution to locations not connected to the pipeline system through its own fleet of tanker trucks and chartered tanker ships.

Based on the extensive network of pipelines and storage facilities, and its tariff structure, CLH has a dominant market position in Spain. Most of the competition comes from storage and truck loading services provided by other companies. CLH also offers secondary distribution services, the most significant being the services provided through CLH Aviation,

which handles aviation fuel at airport locations throughout Spain. This business includes the storage of aviation fuel, loading of aircraft refueling units and the refueling of aircraft. New policies issued by the Spanish airport authority (AENA) to promote competition allow for new non-CLH operators to enter the aircraft-refueling segment of this business. While CLH's share of this segment of the market may reduce over time, its participation in the aviation fuel business is expected to continue.

Earnings from CLH are directly impacted by the demand for refined products including gasoline, diesel, jet fuel and other transportation fuels. Economic growth in Spain over the last decade has been among the highest in the European Union, which has led to increasing demand for energy, including refined products. The central region of the country, in and around Madrid, has seen the largest growth in demand. CLH is in the process of expanding its system over the next several years in order to meet the continued growth expected in this region and to deliver incremental volumes expected from domestic refinery expansions, located primarily in the south of the country. This expansion, which includes an increase in storage capacity and looping of both the northern and southern main lines, is being constructed in phases to match the expected growth in volumes.

OLEODUCTO CENTRAL S.A.

The OCENSA pipeline consists of 829 kilometres (515 miles) of 30-inch and 36-inch pipeline, pumping units, tankage and marine loading facilities, with a capacity to transport 525,000 bpd of crude oil. The pipeline links the Cuisiana and Cupiagua oilfields in the central interior of Colombia to the Port of Coveñas on the Caribbean coast. The Company earns a fixed rate of return on the OCENSA pipeline investment as well as operating fees, through its 100% interest in CITCol.

CORPORATE

Corporate activities are limited to business development activities not attributable to a specific business segment, corporate financing costs and various support personnel costs. In addition, business activities in the development stage or those that may represent an emerging technology may be included in Corporate. These activities are seen as potential growth areas that may have a strategic fit with existing operations or present the opportunity to enhance activity levels in existing operating segments.

GENERAL

EMPLOYEES

At December 31, 2007, Enbridge employed 5,518 employees as set forth in the following table.

Liquids Pipelines	1,254
Gas Pipelines	64
Gas Distribution and Services[1]	2,209
Sponsored Investments[2]	1,788
International	16
Corporate	187
	5,518

Notes:

1 *Although most of Enbridge's employees are non-unionized, included in Gas Distribution and Services are 724 employees of EGD who are unionized and are represented by the Communications, Energy and Paperworkers Union, Local 975 or the International Brotherhood of Electrical Workers, Local 97. The current collective agreements expire in December 2008 and February 2009, respectively.*

2 *Neither EEP nor EIF have employees and both use the services of the Company's wholly-owned subsidiaries for managing and operating their businesses.*

CORPORATE SOCIAL RESPONSIBILITY

At Enbridge, being socially responsible means doing things right, and doing the right thing. Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical way; protecting the environment and the health and safety of people; supporting human rights; and engaging, respecting and supporting the communities and cultures with which the Company works.

CORPORATE GOVERNANCE

A comprehensive system of stewardship and accountability is in place and functioning among directors, management and employees. Enbridge employs a variety of policies, programs and practices to manage corporate governance. Examples include the majority of the Board of Directors being independent; employee and Director compliance with the Company's Statement on Business Conduct; compliance with applicable Sarbanes-Oxley requirements and the Canadian securities regulators' corporate governance guidelines and rules; and the use of internal and external reviews and audits to assess each business segment's compliance with government regulations and our internal policies and management systems, and to provide guidance for making improvements.

ENVIRONMENTAL PERFORMANCE

Climate change is an issue of strategic and operational importance to all Enbridge businesses, regardless of where they are located. The CSR Committee of the Company's Board of Directors has specific oversight responsibility for all climate change-related activities and the development of a carbon management strategy for the Company. The Climate Change Sub-Committee (CCSC), a management committee, meets monthly and provides a technical focus for the corporation that supports all climate-change-related activities across the enterprise. The CCSC reviews business and environmental risks associated with climate change and identifies policies and actions to mitigate this risk. This committee also oversees the development of consistent internal methodologies for greenhouse gas (GHG) inventories and reporting, and approves the reporting protocols to be used. Enbridge has taken, or is taking, many steps to improve the quality of GHG reporting and performance including: undertaking an independent third-party audit of the GHG emissions data management system for the Canadian operations; investing in sustainable energy, including fuel cells, and studying the viability of deploying new technologies to help reduce the Company's GHG emissions; and replacing older cast iron pipe with new polyethylene mains at EGD.

Although the Company carries out spill prevention and detection preventive maintenance programs as part of comprehensive integrity management of the pipelines and facilities, spills of crude oil and petroleum products are not unusual within the liquids pipeline industry and the Company has experienced such spills in the past. Historic spills along the pipeline system may have resulted in soil or groundwater contamination where further remediation may be required. Enbridge continues to voluntarily investigate past leak sites to assess whether any remediation of contaminated lands is required in light of current legislation, in consultation with regulatory agencies and landowners. Also, when a spill does occur, Enbridge routinely conducts a formal de-brief to share lessons learned both locally and across the Company. Communication programs keep property owners and neighbours along rights-of-way informed about the system and enlist their help in the prevention, detection and safe response to pipeline spills.

As noted above, the Company has ongoing monitoring and maintenance programs for its pipelines that contribute to their safe operation. Enbridge endeavors to be a leader in pipeline and system integrity by:

- implementing rigorous preventive maintenance programs;
- pursuing and supporting technology research;
- participating in industry forums to share and exchange knowledge;
- contributing to the development of national pipeline safety standards and industry recommended practices;
- providing technical advisory and training services to pipeline operators around the world; and
- supporting state and provincial excavation one-call efforts to reduce the risk of third-party damage to pipelines.

The Company has set corporate leak-reduction targets across the Liquids Pipelines segment, with performance goals now linked to corporate and individual assessment and compensation. Leak-reduction teams, small-piping-integrity initiatives and changes to engineering standards have all contributed to reductions in reportable leaks at pipeline facilities since 2004. Enbridge's strong focus on advancing pipeline integrity is aimed at technological advances as well as understanding the science of how to find, mitigate and prevent leaks or ruptures on the pipeline systems.

Enbridge is also committed to helping customers use energy more wisely. Between 1995 and the end of 2007, EGD was successful in helping its customers reduce their natural gas consumption by approximately 127.1 bcf through

participation in its demand side management programs. This reduction translates into the avoidance of approximately 6.8 million tonnes of GHG emissions being released into the atmosphere.

Other environmental initiatives include: continually looking for opportunities to update gas facilities and pipelines in ways that contribute to operating, environmental and safety goals; incorporating ways to conserve wildlife habitat into project planning and maintenance activities; and reducing energy use through efficiency improvements and conservation efforts.

All of the Company's operations are subject to federal, state or local laws and regulations related to environmental protection and operational safety. To the best of the Company's knowledge, the operations of all affiliated systems are in material compliance with applicable environmental and safety regulations. Enbridge cannot impose policies and procedures on the entities it does not operate; however, these entities are still required to comply with the applicable laws and regulations of their country.

SOCIAL PERFORMANCE

Support for universal human rights is one of Enbridge's core CSR principles and it has reinforced this principle with comprehensive policies and practices addressing human rights. For example, Enbridge was one of the first Canadian companies to adopt the internationally recognized Voluntary Principles on Security and Human Rights (Voluntary Principles), which stress the importance of promoting and protecting human rights throughout the world and the constructive role business and civil society – including non-governmental organizations, labour and trade unions and local communities – can play in advancing these goals. The Voluntary Principles guide companies in maintaining the safety and security of their operations within an operating framework that promotes respect for human rights and fundamental freedoms.

Stakeholder relations involves developing and maintaining positive relationships with employees; contractors; suppliers; customers; landowners; investors; environmental groups; business partners; government agencies and regulators; provincial, state and federal legislators; local officials; community residents; and the media. Enbridge engages with stakeholders in many ways, including proactive communication and consultation programs to support the unprecedented number of new construction projects being undertaken and promoting public awareness regarding existing facilities.

Enbridge makes voluntary contributions to charitable and non-profit organizations in the areas of education, health, environment, social services, arts and culture, community leadership and volunteerism. The Company focuses on using dollars, partnerships and human capital to support organizations that contribute to the economic and social development of communities where Enbridge employees live and work.

FINANCIAL AND OPERATIONAL EFFECTS

Risks of significant costs and liabilities are inherent in the nature of the Company's operations and there can be no assurance that such costs and liabilities will not be incurred.

The environmental protection requirements applicable to the Company do not adversely affect the operations, competitive position, capital expenditures program or level of earnings. However, the risk of substantial liabilities is inherent in the Company's operations and there can be no assurance that such liabilities will not be incurred. Regular internal reviews and audits are conducted to assess compliance with legislation and Company policy. Enbridge believes that its operations are in material compliance with all applicable safety and environmental regulations governing their operations.

RISK FACTORS

A discussion of the Company's risk factors can be found in the 2007 Year End MD&A under the subheading "Business Risks" for each of the five operating segments as well as under the heading "Risk Management".

DIVIDENDS

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. While balancing shareholders' preference for income and its own need for capital, the Company targets to pay out approximately 60% to 70% of adjusted operating earnings as dividends. Dividends on the Preferred Shares, Series A, are fixed and are paid quarterly.

There are no restrictions that currently prevent the Company from paying dividends. However, in the event of liquidation, dissolution or winding-up of the Company, the preferred shareholders have priority in the payment of dividends over the common shareholders. As well, restrictions in the credit or financing agreements entered into by the Company or the provisions of applicable law may preclude the payment of dividends in certain circumstances.

(Canadian dollars per share)	2007	2006	2005
Common Shares	1.2300	1.1500	1.0375
Preferred Shares, Series A	1.3750	1.3750	1.3750

DESCRIPTION OF CAPITAL STRUCTURE

SHARE CAPITAL

Enbridge's authorized share capital consists of an unlimited number of Common Shares with no par value and an unlimited number of preferred shares. At Year End, there were 368.5 million Common Shares and 5.0 million Series A Preferred Shares issued and outstanding.

Common Shares

The holders of the Common Shares are entitled to receive dividends if, as and when declared by the Board of Directors of the Company. The holders of the Common Shares are entitled to receive notice of and to attend all meetings of shareholders and are entitled to one vote per Common Share held at all such meetings. In the event of the liquidation, dissolution or winding up of the Company or other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Common Shares will be entitled to participate ratably in any distribution of the assets of the Company.

The Company has a Shareholder Rights Plan that is 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 the 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 Company's Board of Directors. Should such an event 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. The plan was reconfirmed at the 2005 annual meeting of shareholders and must be reconfirmed at every third annual meeting thereafter. The renewal of this plan is proposed for approval at the 2008 shareholders' meeting.

Enbridge's Dividend Reinvestment and Share Purchase Plan enables registered shareholders of the Company to purchase additional common shares by reinvesting all of the cash dividends paid on the common shares and also by making optional cash payments of up to $5,000 per quarter, in both cases without incurring brokerage or other transaction expenses. Effective with dividends payable on March 1, 2008, participants in the Company's Dividend Reinvestment and Share Purchase Plan will receive a 2% discount on the purchase of common shares with reinvested dividends.

Enbridge also has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plan are generally fully exercisable after four years and expire ten years after the grant date.

Preferred Shares

The 5.0 million 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, quarterly preferential dividends of $1.375 per share per year. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 per share plus all accrued and unpaid dividends.

Preferred Shares may be issued in one or more series. The Board of Directors may determine the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares before the issue of such series. Holders of

the Preferred Shares are not entitled to vote at any meeting of the shareholders of the Company, except as required by law. The Preferred Shares are entitled to priority over the Common Shares of the Company with respect to the payment of dividends and the distribution of assets of the Company in the event of any liquidation, dissolution or winding up of the Company's affairs.

RATINGS

The following table sets forth the ratings assigned to the Company's Preferred Shares, Series A, Medium-Term Notes (MTNs) and Unsecured Debt and Commercial Paper by Dominion Bond Rating Service Limited (DBRS), Moody's Investor Services, Inc. (Moody's) and Standard & Poor's Ratings Services (S&P).

	DBRS	Moody's	S&P
Preferred Shares, Series A	Pfd-2 (low)[1]	Baa3	BBB
MTNs and Unsecured Debt	A[1]	Baa1	A-
Commercial Paper	R-1 (low)	Not Rated	A-1 (low)
Rating Outlook	Negative[1]	Stable	Stable

Note:

1 On November 6, 2007, DBRS placed Enbridge's long-term debt and preferred share ratings on Negative trend; commercial paper remained on a stable outlook.

The credit ratings accorded by these rating agencies are not recommendations to purchase, hold or sell the shares or securities and such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A description from the rating agency for each credit rating listed in the table above is set out below.

Dominion Bond Rating Service

DBRS has different rating scales for short and long-term debt and preferred shares. "High" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the "middle" of this category. The Pfd-2 (low) rating assigned to Enbridge's Preferred Shares are the second highest of six rating categories for preferred shares. Preferred shares rated Pfd-2 are of satisfactory credit quality. Protection of dividends and principal is still substantial, but earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. The A rating assigned to Enbridge's MTNs and unsecured debentures is the third highest of eight categories for long-term debt. Long-term debt rated A is of satisfactory credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than that of AA rated entities. While A is a respectable rating, entities in this category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. The R-1 (low) rating assigned to Enbridge's commercial paper is the third highest of ten rating categories and indicates satisfactory credit quality. The overall strength and outlook for key liquidity, debt and profitability ratios is not normally as favorable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence on its industry.

Moody's Investor Services

Moody's has different rating scales for short and long-term obligations. Numerical modifiers 1, 2 and 3 are applied to each rating classification, with 1 being the highest and 3 being the lowest. The Baa3 rating assigned to Enbridge's Preferred Shares and the Baa1 rating assigned to Enbridge's MTNs and unsecured debentures is the fourth highest of nine rating categories for long-term obligations. Obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and, as such, may possess certain speculative characteristics.

Standard & Poor's

S&P has different rating scales for short and long-term obligations. Ratings may be modified by the addition of a plus (+) or a minus (-) sign to show the relative standing within a particular rating category. The BBB rating assigned to Enbridge's preferred shares is the fourth highest of ten rating categories for long-term obligations. An obligor rated BBB has adequate capacity to meet its financial commitments; however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The A- rating assigned to Enbridge's MTNs and unsecured debentures is the third highest of ten rating categories. An A rating indicates the obligor has strong capacity to meet its financial commitments but is somewhat more susceptible to the

adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories. The rating of A-1 assigned to Enbridge's commercial paper is the highest of eleven rating categories for short-term obligations. An obligor rated A-1 has strong capacity to meet its financial commitments.

MARKET FOR SECURITIES

The Common Shares of the Company are traded on the Toronto Stock Exchange (TSX) in Canada, the principal market for Enbridge's common shares, and on the New York Stock Exchange (NYSE) in the U.S. under the symbol ENB. The following table sets forth the monthly price range and volume traded for Enbridge's Common Shares on the TSX and NYSE.

	TSX (ENB)				NYSE (ENB)			
	High ($)	Low ($)	Close ($)	Volume Traded	High (US$)	Low (US$)	Close (US$)	Volume Traded
January 2007	41.48	38.21	38.31	19,638,312	35.40	32.20	32.20	3,360,700
February 2007	38.54	36.76	37.11	22,126,577	32.95	31.41	31.73	2,607,138
March 2007	39.00	36.50	37.66	18,791,712	33.68	30.93	32.65	3,167,591
April 2007	37.90	36.48	36.60	13,592,088	33.71	32.06	33.00	2,558,411
May 2007	38.35	36.09	37.95	17,281,300	35.85	32.54	35.56	4,596,850
June 2007	38.24	35.21	35.90	14,967,938	36.15	32.87	33.78	4,514,012
July 2007	38.74	35.68	37.83	14,999,173	37.13	33.68	35.40	3,651,500
August 2007	37.97	33.62	35.60	18,241,872	36.02	31.26	33.68	5,146,500
September 2007	37.00	34.90	36.44	14,072,333	36.99	33.21	36.67	3,794,200
October 2007	40.97	36.25	40.91	15,237,385	43.29	36.31	42.81	4,386,700
November 2007	40.96	35.75	37.11	18,810,727	44.29	36.20	37.27	7,251,559
December 2007	40.20	37.16	40.01	16,061,642	41.91	36.73	40.43	3,995,460

In addition, the Company's Preferred Shares, Series A are traded on the TSX under the symbol ENB.PR.A. The following table sets forth the monthly price range and volume traded for Enbridge's Preferred Shares.

	High ($)	Low ($)	Close ($)	Volume Traded
January 2007	25.99	25.46	25.46	43,998
February 2007	25.99	25.16	25.59	61,815
March 2007	25.63	25.19	25.48	82,546
April 2007	25.57	25.10	25.33	51,543
May 2007	25.49	24.53	25.01	387,592
June 2007	25.60	24.75	25.12	81,313
July 2007	25.35	25.04	25.18	30,630
August 2007	25.32	24.92	25.15	48,907
September 2007	25.23	24.50	24.86	52,589
October 2007	25.00	23.56	24.37	54,463
November 2007	25.10	24.50	24.97	134,705
December 2007	25.40	24.51	25.33	51,095

The following table outlines the securities issued by the Company and its wholly-owned subsidiaries during 2007 that are not listed or quoted on an exchange. These are in the form of unsecured medium term notes.

Issuer	Principal Amount *(millions)*	Coupon	Issue Date	Maturity Date	Issue Price
Enbridge Inc.	US$400	5.60%	March 27, 2007	April 1, 2017	US$99.932
Enbridge Inc.	US$400	5.80%	May 31, 2007	June 15, 2014	US$99.906
Enbridge Gas Distribution Inc.	$200	5.16%	December 3, 2007	December 4, 2017	$99.984

There are no provisions associated with this debt that entitle debt holders to voting rights. In June, Enbridge (US) Inc. issued a zero-coupon debt instrument for US$250 million (principal only) with a maturity date of June 20, 2022. From time to time, the Company also issues commercial paper for various terms. Enbridge also has credit facilities that bear interest at market rates.

Also, on February 2, 2007, Enbridge closed the issuance of 13.5 million common shares for $38.75 per share to the public and issued 1.5 million common shares to Noverco for $38.75 per share. Net proceeds from both offerings totaled $566.4 million.

DIRECTORS AND OFFICERS

As at January 31, 2008, the directors and all officers of Enbridge (including the executive officers listed below) as a group beneficially owned, directly or indirectly, 1,379,542 Common Shares of the Company, representing less than 1% of the issued and outstanding Common Shares on that date. The information as to shares beneficially owned or over which control or direction is exercised, not being within the knowledge of the Company, has been furnished by the respective directors and officers individually. The directors and officers do not beneficially own, directly or indirectly, any voting securities of any subsidiary of the Company.

DIRECTORS

The following table sets forth the names of the Directors of Enbridge Inc. on February 20, 2008, their municipalities of residence, their respective principal occupations within the five preceding years and the year from which they first became a Director of the Company (except where otherwise noted). Each Director elected holds office until the next annual meeting of shareholders or until a successor is duly elected or appointed.

Name and Place of Residence	Principal Occupation During the Five Preceding Years	Director Since[1]
David A. Arledge Naples, Florida USA	Corporate Director. Chair of the Board of Directors of Enbridge Inc. since 2005.	2002
James J. Blanchard[2] Beverly Hills, Michigan USA	Chairman, Government Affairs, DLA Piper U.S., LLP (law firm) since June 2006. United States Ambassador to Canada from 1993 to 1996.	1999
J. Lorne Braithwaite Dublin, Ireland	Corporate Director. President & Chief Executive Officer of Cambridge Shopping Centres Limited (developer and manager of retail shopping malls in Canada) from 1978 to 2001.	1989
Patrick D. Daniel Calgary, Alberta Canada	President & Chief Executive Officer of Enbridge since January 2001.	2000
J. Herb England Naples, Florida USA	President & Chief Executive Officer of Stahlman-England Irrigation Inc. (contracting company) since January 2000.	2007
E. Susan Evans Calgary, Alberta Canada	Corporate Director.	1996

David A. Leslie Toronto, Ontario Canada	Corporate Director. Chairman & Chief Executive Officer of Ernst & Young LLP (public accounting firm) from 1999 to 2004.	2005
Robert W. Martin[3] Toronto, Ontario Canada	Corporate Director.	1992
George K. Petty San Luis Obispo, California USA	Corporate Director.	2001
Charles E. Shultz Calgary, Alberta Canada	Chairman & Chief Executive Officer of Dauntless Energy Inc. (private oil and gas corporation) since 1995.	2004
Dan C. Tutcher Houston, Texas USA	Corporate Director. Group Vice President, Transportation South of Enbridge Inc., President of Enbridge Energy Company, Inc. and Enbridge Energy Management L.L.C. from 2001 to 2006.	2006
Catherine L. Williams Calgary, Alberta Canada	Corporate Director. Chief Financial Officer of Shell Canada Limited from 2003 to 2007. Controller of Shell Europe Oil Products from 2001 to 2003.	2007

Notes:

1 *"Director Since" refers to the year the person named was elected or appointed as a Director of the Company or of its predecessor parent, Interprovincial Pipe Line Inc.*

2 *On April 10, 2006, the Ontario Securities Commission (OSC) issued a temporary cease trade order against Bennett Environmental Inc. (Bennett), and subsequently a cease trade order on April 24, 2006, after Bennett failed to file its annual financial statements and related management's discussion and analysis for the year ended December 31, 2005. Under such orders, certain directors, officers and insiders of Bennett, including Governor Blanchard, were prohibited from trading Bennett securities until the OSC was in receipt of the necessary filings. Bennett made the requisite filings on or about May 30, 2006 and the cease trade order lapsed on June 19, 2006. Governor Blanchard resigned from Bennett on August 7, 2006.*

3 *On December 2, 2003, the OSC issued a temporary cease trade order against Atlas Cold Storage Income Trust (Atlas), and subsequently a cease trade order on December 15, 2003, after Atlas failed to file its interim financial statements for its nine-month period ended September 30, 2003. Under such orders, certain trustees, including Mr. Martin, were prohibited from trading Atlas trust units until the OSC was in receipt of the necessary filings. Atlas made the requisite filings on January 27, 2004 and the cease trade order lapsed on February 2, 2004. Mr. Martin did not stand for re-election as a Trustee of Atlas at the Atlas annual meeting held in June 2004.*

Enbridge has four committees of the Board of Directors: (1) Audit, Finance & Risk Committee (AFR Committee); (2) Governance Committee; (3) Human Resources and Compensation Committee (HRC Committee); and (4) Corporate Social Responsibility Committee (CSR Committee). The members of each of these committees, as of Year End, are identified below:

Director	AFR Committee	Governance Committee	HRC Committee	CSR Committee
David A. Arledge		ü	ü	
James J. Blanchard		ü		Chair
J. Lorne Braithwaite			ü	ü
J. Herb England	ü	ü		
E. Susan Evans			ü	ü
David A. Leslie	Chair	ü		
Robert W. Martin	ü		ü	
George K. Petty	ü	Chair		
Charles E. Shultz	ü		Chair	
Dan C. Tutcher		ü		ü
Catherine L. Williams	ü			ü

OFFICERS

The following table sets forth the names of the executive officers, their current office with the Company on February 20, 2008, their municipality of residence and their principal occupations for the five preceding years.

Name and Place of Residence	Present Position Held	Principal Occupation During the Five Preceding Years
Patrick D. Daniel Calgary, Alberta Canada	President & Chief Executive Officer	President & Chief Executive Officer since January 2001.
J. Richard Bird Calgary, Alberta Canada	Executive Vice President, Chief Financial Officer & Corporate Development	Executive Vice President, Chief Financial Officer & Corporate Development since January 2008. Executive Vice President, Liquids Pipelines from May 2006 to January 2008. Group Vice President, Liquids Pipelines from May 2005 to May 2006. Group Vice President, Transportation North from May 2001 to May 2005.
Stephen J.J. Letwin The Woodlands, Texas USA	Executive Vice President, Gas Transportation & International	Executive Vice President, Gas Transportation & International since May 2006. Group Vice President, Gas Strategy & Corporate Development from April 2003 to May 2006. Group Vice President, Distribution & Services from September 2000 to April 2003.
Al Monaco Calgary, Alberta Canada	Executive Vice President, Major Projects	Executive Vice President, Major Projects since January 2008. President, Enbridge Gas Distribution Inc. from September 2006 to January 2008. Senior Vice President, Corporate Planning & Development from June 2003 to September 2006. Vice President, Financial Services from February 2002 to June 2003.
Stephen J. Wuori Calgary, Alberta Canada	Executive Vice President, Liquids Pipelines	Executive Vice President, Liquids Pipelines since January 2008. Executive Vice President, Chief Financial Officer & Corporate Development from May 2006 to January 2008. Group Vice President & Chief Financial Officer from April 2003 to May 2006. Group Vice President, Planning & Development from September 2000 to March 2003.
Bonnie D. DuPont Calgary, Alberta Canada	Group Vice President, Corporate Resources	Group Vice President, Corporate Resources since September 2000.
David T. Robottom Calgary, Alberta Canada	Group Vice President, Corporate Law	Group Vice President, Corporate Law since June 2006. Partner, Stikeman Elliott LLP (law firm) from February 2004 to May 2006. Partner, Fraser Milner Casgrain LLP (law firm) to January 2004. Chief Executive Officer, Fraser Milner Casgrain LLP to January 2003.
Leigh S. Cruess Calgary, Alberta Canada	Senior Vice President, International & Gas Services	Senior Vice President, International & Gas Services since January 2008. Senior Vice President, International from September 2006 to January 2008. Vice President, Financial Services from April 2003 to September 2006.
James A. Schultz Calgary, Alberta Canada	Senior Vice President, New Ventures	Senior Vice President, New Ventures since September 2006. Senior Vice President from April 2003 to September 2006. President of Enbridge Gas Distribution Inc. from June 2001 to September 2006.
John K. Whelen Calgary, Alberta Canada	Senior Vice President, Corporate Development	Senior Vice President, Corporate Development since September 2006. Vice President and Treasurer from February 2002 to August 2006.

CONFLICTS OF INTEREST

Directors and officers of Enbridge and its subsidiaries are required to disclose the existence of potential conflicts in accordance with Enbridge policies governing directors and officers and in accordance with the Canada Business Corporations Act. Although some of the directors sit on boards or may be otherwise associated with companies that ship crude oil and/or natural gas on Enbridge's pipeline systems, Enbridge as a common carrier in Canada cannot, under its tariff, deny transportation service to a credit-worthy shipper. Further, due to the specialized nature of the industry, Enbridge believes it is important for its Board to be composed of qualified and knowledgeable directors, so some of them must come from oil and gas producers and shippers; the Governance Committee closely monitors relationships among directors to ensure that business associations do not affect the Board's performance. In a circumstance where a director declares an interest in any material contract or material transaction being considered at a meeting, the director generally absents himself or herself from the meeting during the consideration of the matter, and does not vote on the matter.

AUDIT, FINANCE & RISK COMMITTEE

The Audit, Finance & Risk Committee's Terms of Reference are attached to this AIF as Appendix A and can also be found on the Company's website at www.enbridge.com.

RELEVANT EDUCATION AND EXPERIENCE OF MEMBERS

The members of the AFR Committee at Year End were David A. Leslie (Chair), J. Herb England, Robert W. Martin, George K. Petty, Charles E. Shultz and Catherine L. Williams. The Board believes the composition of the AFR Committee reflects a high level of financial literacy and expertise. Each member of the AFR Committee has been determined by the Board to be "independent" and "financially literate" within the meaning of the definitions under Canadian and U.S. securities laws and the NYSE rules. In addition, the Board has determined that Messrs. England and Leslie are each an "Audit Committee Financial Expert" as that term is defined under U.S. securities laws. The Board has made these determinations based on the education and breadth and depth of experience of each member of the AFR Committee. The following is a description of the education and experience, apart from their respective roles as Directors of Enbridge, of each member of the AFR Committee that is relevant to the performance of his or her responsibilities as a member of the AFR Committee.

David A. Leslie, F.C.A.

Mr. Leslie is a chartered accountant and in his career of over 30 years, he was, among other things, personally involved in and then actively supervised persons engaged in preparing, auditing, analyzing and evaluating financial statements. He is the former Chairman and Chief Executive Officer of Ernst & Young LLP. He is also a director and member of the audit committees of Canwest Global Communications Corp., Crombie REIT, Empire Company Limited, Enbridge Gas Distribution Inc., Imris Inc. and Sobeys Inc.

J. Herb England

Mr. England acquired extensive financial experience and exposure to accounting and financial issues during a lengthy career with the John Labatt Limited group of companies, including as Chief Financial Officer of John Labatt Limited. He is currently President and Chief Executive Officer of Stahlman-England Irrigation Inc., a contracting company in Florida.

Robert W. Martin

Mr. Martin acquired significant financial experience and exposure to accounting and financial issues as President, Chief Executive Officer and director of various corporations and in various finance positions. He was the President and Chief Executive Officer of Consumers Gas Company (now Enbridge Gas Distribution Inc.) where he was responsible for financial aspects related to that corporation. He has acted as a member and Chair of other audit committees, and currently serves as Chair of the audit committee of HSBC Bank Canada.

George K. Petty

Mr. Petty acquired significant financial experience and exposure to accounting and financial issues during his lengthy career, which included serving as President and Chief Executive Officer of Telus Corporation from 1994 to 1999. He has acted as a member of other audit committees.

Charles E. Shultz

Mr. Shultz acquired significant financial experience as a business executive and board member of several large Canadian and U.S. public companies. He served as President and Chief Executive Officer of Gulf Canada Resources Limited from 1990 to 1995 and has served as a director and Chairman of Canadian Oil Sands Limited since its inception.

Catherine L. Williams

Ms. Williams held senior finance positions during a 30-year career in business which included international experience. She worked for 20 years in the Shell group of companies, including as Chief Financial Officer of Shell Canada Limited from 2003 to 2007 and as Controller of Shell Europe Oil Productions from 2001 to 2003.

PRE-APPROVAL POLICIES AND PROCEDURES

The AFR Committee has adopted a policy that requires pre-approval by the Committee of any services to be provided by the auditors, whether audit or non-audit services. The policy prohibits the Company from engaging the auditors to provide the following non-audit services:

- bookkeeping or other services related to accounting records and financial statements;
- financial information systems design and implementation;
- appraisal or valuation services, fairness opinions, or contribution-in-kind reports;
- actuarial services;
- internal audit outsourcing services;
- management functions or human resources;
- broker or dealer, investment adviser, or investment banking services;
- legal services; and
- expert services unrelated to the audit.

The AFR Committee believes that the policy will protect the Company from the potential loss of independence of the external auditors. The AFR Committee has also adopted a policy which prohibits the Company from hiring former employees of the auditors who provided more than 10 hours of audit, review or attest services for the Company or its subsidiaries within the one year preceding the commencement of the audit of the current year's financial statements.

A copy of the policies and procedures applicable to the pre-approval of non-audit services by the Company's external auditors may be obtained from the Corporate Secretary of the Company by sending a written request to 3000, 425 - 1st Street S.W., Calgary, Alberta, T2P 3L8, by faxing a written request to (403) 231-5929, by calling (403) 231-3900 or by sending an e-mail request to corporatesecretary@enbridge.com.

EXTERNAL AUDITOR SERVICES – FEES

The following table sets forth all services rendered by the auditors, PricewaterhouseCoopers (PwC), by category, together with the corresponding fees billed by the auditors for each category of service for the financial years ended December 31, 2007 and 2006.

	2007	2006	Description of Fee Category
Audit Fees	$3,700,662	$3,688,620	Represents the aggregate fees billed by the Company's auditors for audit services.
Audit-Related Fees	269,296	248,645	Represents the aggregate fees billed for assurance and related services by the Company's auditors that are reasonably related to the performance of the audit or review of the Company's financial statements and are not included under "Audit Fees". During fiscal 2007 and 2006, the services provided in this category included due diligence related to prospectus offerings, technical guidance, Sarbanes-Oxley work and other items.
Tax Fees	255,929	310,599	Represents the aggregate fees billed for professional services rendered by the Company's auditors for tax compliance, tax advice and tax planning.
All Other Fees	88,354	388,444	Represents the aggregate fees billed for products and services provided by the Company's auditors other than those services reported under "Audit Fees", "Audit Related Fees" and "Tax Fees", including Canadian Public Accountability Board fees, French translation work and process reviews.
Total Fees	$4,314,241	$4,636,308	

LEGAL PROCEEDINGS

Information related to the Enbridge's legal proceedings can be found in Note 24, "Commitments and Contingencies" to the Audited Consolidated Financial Statements as at and for the year ended December 31, 2007.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal shareholder of Enbridge, or associate or affiliate of these persons, has any material interest, direct or indirect, in any transaction within the last three years that has materially affected or will materially affect Enbridge.

REGISTRAR AND TRANSFER AGENT

The registrar and transfer agent for the Company's Common Shares is CIBC Mellon Trust Company:

In Canada:
CIBC Mellon Trust Company
P.O. Box 7010, Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Telephone: 1-800-387-0825 or
416-643-5000 outside of North America
Website: www.cibcmellon.com/investorinquiry

In the U.S.:
BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, New Jersey
U.S.A. 07310

The registrar and transfer agent for the Company's Preferred Shares, Series A is CIBC Mellon Trust Company:

In Canada:
CIBC Mellon Trust Company
P.O. Box 7010, Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Telephone: 1-800-387-0825 or
416-643-5000 outside of North America
Website: www.cibcmellon.com/investorinquiry

MATERIAL CONTRACTS

Enbridge has not entered into any material contracts, outside the ordinary course of business.

INTERESTS OF EXPERTS

The Company's auditors are PricewaterhouseCoopers LLP, Chartered Accountants. PwC issued an auditors' report in respect of Enbridge's consolidated financial statements, with accompanying notes as at December 31, 2007 and 2006 and for each of the years in the three year period ended December 31, 2007. PwC has also provided an opinion on the effectiveness of internal control over financial reporting as at December 31, 2007 and 2006. Both of these opinions are dated February 20, 2008.

PwC has advised that it is independent with respect to Enbridge within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the U.S. Securities and Exchange Commission.

ADDITIONAL INFORMATION

Additional information about Enbridge is available on our website at www.enbridge.com and on SEDAR (System for Electronic Document Analysis and Retrieval) at www.sedar.com in Canada, and on the U.S. Securities and Exchange Commission's website (EDGAR) at www.sec.gov. The aforementioned information is made available in accordance with legal requirements and is not incorporated by reference into this AIF.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans, where applicable, is contained in the Management Information Circular for our most recent annual meeting of shareholders at which directors were elected.

Additional financial information is provided in Enbridge's Consolidated Financial Statements and MD&A for the most recently completed financial year.

Enbridge Gas Distribution Inc.

Additional information about EGD can be found in its AIF, Financial Statements and MD&A which have been filed with Canadian Securities Regulatory Authorities and are available at www.sedar.com. These documents are not incorporated by reference into this AIF.

Enbridge Energy Partners, L.P. and Enbridge Energy Management, L.L.C.

Additional information about EEP and EEM can be found in their Annual Reports on Form 10-K that have been filed with the U.S. Securities and Exchange Commission. These documents contain detailed disclosure with respect to each entity and are publicly available at www.sec.gov. No part of the Form 10-K filed by EEP or by EEM is incorporated by reference into this AIF.

Enbridge Income Fund

Additional information about EIF can be found in its Annual Report and AIF filed with Canadian Securities Administrators in Canada. The AIF and the Annual Report, which includes Consolidated Financial Statements and MD&A, contain detailed disclosure with respect to the Enbridge Income Fund and are publicly available at www.sedar.com. EIF's Annual Report, Consolidated Financial Statements, MD&A and AIF are not incorporated by reference into this AIF.

Enbridge Pipelines Inc.

Additional information about Enbridge Pipelines Inc. can be found in its AIF, Financial Statements and MD&A which have been filed with Canadian Securities Regulatory Authorities and are available at www.sedar.com. These documents are not incorporated by reference into this AIF.

APPENDIX A

AUDIT, FINANCE & RISK COMMITTEE TERMS OF REFERENCE

I. CONSTITUTION

There shall be a committee, to be known as the Audit, Finance & Risk Committee (the "Committee"), of the Board of Directors of Enbridge Inc.

II. MEMBERSHIP

Following each annual meeting of shareholders of the Corporation, the Board shall elect from its members, not less than three (3) Directors to serve on the Committee (the "Members"). The Members and the Chair of the Committee are elected by the Board following the nomination of Directors by the Governance Committee. No Member of the Committee shall be an officer or employee of the Corporation or any of the Corporation's affiliates. All members of the Committee shall, in the judgment of the Board, be unrelated and independent and shall satisfy applicable stock exchange and legal requirements. Determinations on whether a Director meets the requirements for membership on the Committee shall be made by the Board. At least one member of the Committee shall be a "financial expert" as determined by the Board and as defined by American legal or regulatory requirements. No Director may serve as a member of the Committee if such Director also serves on the audit committees of more than two other public entities unless the Board determines that such simultaneous service would not impair the ability of such Director to effectively serve on the Committee.

Any Member may be removed or replaced at any time by the Board and shall cease to be a Member upon ceasing to be a Director of the Corporation. Each Member shall hold office until the close of the next annual meeting of Shareholders of the Corporation or until the Member ceases to be a Director, resigns or is replaced, whichever first occurs. Vacancies may be filled by the Board with nominees approved by the Governance Committee.

III. MEETINGS

The Committee shall convene at such times and places designated by its Chair or whenever a meeting is requested by a Member, the Board, an officer, the internal auditor or the external auditors of the Corporation. A minimum of twenty-four (24) hours notice of each meeting shall be given to each Member and to the internal and external auditors.

A majority of the committee shall be duly convened if all Members are present, or at least a majority of the Members are present. A quorum at a meeting shall consist of at least a majority of Members. Where the Members consent, and proper notice has been given or waived, Members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other, and a Member participating in such a meeting by any such means is deemed to be present at that meeting.

In the absence of the Chair of the Committee, the Members may choose one (1) of the Members to be the Chair of the meeting.

At the invitation of a Member, other Board members, officers or employees of the Corporation, the external auditors, external counsel and other experts or consultants may attend any meeting of the Committee.

Members of the Committee may meet separately with any member of management, the external auditors, the internal auditor, internal or external counsel or any other expert or consultant.

Minutes shall be kept of all meetings of the Committee.

IV. FUNDING

The Corporation shall provide appropriate funding, as determined by the Committee, for the payment of compensation to the external auditors and any independent counsel, experts or advisors employed by the Committee and administrative expenses of the Committee.

V. REVIEW OF CHARTER

The Committee shall review and reassess the adequacy of its Terms of Reference at least annually and propose recommended changes to the Board.

VI. DUTIES AND RESPONSIBILITIES OF THE CHAIR

The Chair is responsible for:

A. convening Committee meetings and designating the times and places of those meetings;

B. ensuring Committee meetings are duly convened and that quorum is present when required;

C. working with Management on the development of agendas and related materials for the Committee meetings;

D. ensuring Committee meetings are conducted in an efficient, effective and focused manner;

E. ensuring the Committee has sufficient information to permit it to properly make decisions when decisions are required;

F. providing leadership to the Committee and to assist the Committee in reviewing and monitoring its responsibilities; and

G. reporting to the Board on the recommendations and decisions of the Committee.

VII. DUTIES AND RESPONSIBILITIES

The Committee provides assistance to the Board in fulfilling its oversight responsibility to the shareholders, the investment community and others, relating to the integrity of the Corporation's financial statements and the financial reporting process, the management information systems and financial controls, the internal audit function, the external auditors' qualifications, independence, performance and reports, the Corporation's compliance with legal and regulatory requirements and the risk identification, assessment and management program. In so doing, it is the Committee's responsibility to maintain an open avenue of communication between the Committee, the external auditors, the internal auditors and management of the Corporation.

Management is responsible for preparing the interim and annual financial statements and financial disclosure of the Corporation and for maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, executed, recorded and reported properly. The Committee's role is to provide meaningful and effective oversight and counsel to management without assuming responsibility for management's day-to-day duties.

In performance of its duties and responsibilities, the Committee shall have the right as it determines necessary to carry out its duties to engage independent counsel, experts and other advisors, to inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates, and to discuss with the officers of the Corporation, its subsidiaries and affiliates, the internal auditor and the external auditors, such accounts, records and other matters as any Member considers appropriate.

The Committee shall have the following specific duties and responsibilities:

A. DUTIES AND RESPONSIBILITIES RELATED TO THE EXTERNAL AUDITORS.

The Committee shall:

(i) (a) be responsible for the appointment, compensation, oversight, retention and termination of the external auditors who shall report directly to the Committee, provided that the appointment of the auditor shall be subject to shareholder approval; and

(b) be responsible for the appointment, compensation, oversight, retention and termination of any other registered public accounting firm for audit, review or attestation services;

(ii) review and approve the terms of the external auditors' annual engagement letter, including the proposed audit fees;

(iii) review and approve all engagements for audit services and non-audit services to be provided by the external auditors and, as necessary, consider the potential impact of such services on the independence of the external auditors;

(iv) review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence;

(v) at least annually, obtain and review a report by the external auditors describing the firm's internal quality-control procedures, any material issues raised by the most recent internal quality-control review or peer review of the firm or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the external auditors and any steps taken to deal with any such issues and all relationships between the external auditors and the Corporation;

(vi) resolve disagreements, if any, between management and the external auditors regarding financial reporting;

(vii) inform the external auditors and management that the external auditors shall have access directly to the Committee at all times, as well as the Committee to the external auditors and that the external auditors are ultimately accountable to the Committee as representatives of the shareholders of the Corporation;

(viii) discuss with management and the external auditors any correspondence from or with regulators or governmental agencies, any employee complaints or any published reports that raise material issues regarding the Corporation's financial statements or accounting policies; and

(ix) establish hiring policies for employees or former employees of the external auditors.

B. DUTIES AND RESPONSIBILITIES RELATED TO AUDITS AND FINANCIAL REPORTING.

The Committee shall:

(i) review the engagement terms and the audit plan with the external auditors and with the Corporation's management;

(ii) review with management and the Corporation's external auditors the Corporation's financial reporting in connection with the annual audit and the preparation of the financial statements, including, without limitation, the judgment of the external auditors as to the quality, not just the acceptability of, and the appropriateness of the Corporation's accounting principles as applied in its financial reporting and the degree of aggressiveness or conservatism of the Corporation's accounting principles and underlying estimates;

(iii) review with management and the external auditors and make recommendations to the Board on all financial statements and financial disclosure which require approval by the Board including:

(a) the Corporation's annual financial statements including the notes thereto and "Management's Discussion and Analysis";

(b) any report or opinion to be rendered in connection therewith;

(c) any change or initial adoption in accounting policies and their applicability to the business;

(d) any audit problems or difficulties and management's response;

(e) all significant adjustments proposed by the external auditors; and

(f) satisfying itself that there are no unresolved issues between management and the external auditors that could reasonably be expected to materially affect the financial statements.

(iv) review the Corporation's interim financial results, including the notes thereto and "Management's Discussion and Analysis" with management and the external auditors and approve the release thereof by management or recommend approval thereof to the Board for release by the Board;

(v) review annually the approach taken by management in the preparation of earnings press releases, as well as financial information and earnings guidance provided to analysts and rating agencies;

(vi) discuss with the external auditors their perception of the Corporation's internal audit and accounting personnel, and any recommendations which the external auditors may have;

(vii) review with management, the external auditors and, as necessary, internal and external legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements;

(viii) review with management and monitor the funding exposure of the Corporation under the Corporation's pension plans and review annually and approve the annual report and financial statements applicable to each of the pension plans;

(ix) annually or more frequently as deemed necessary, meet separately with management and the external auditors, and at least annually with the internal auditors, to review issues and matters of concern respecting audits and financial reporting processes;

(x) review with the Corporation's management and, as deemed necessary, review with the external auditors, any proposed changes in or initial adoption of accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of the Corporation's management that may be material to financial reporting;

(xi) review with the Corporation's management and, as deemed necessary, with the external auditors, significant financial reporting issues arising during the fiscal period, including the methods of resolution;

(xii) review any problems experienced by the external auditors in performing an audit, including any restrictions imposed by the Corporation's management or significant accounting issues on which there was a disagreement with the Corporation's management;

(xiii) review the post-audit or management letter containing the recommendations of the external auditors and the response of the Corporation's management, if any, including an evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation (in respect of the scope of review of internal controls by the external auditors, the review is carried out to enable the external auditors to express an opinion on the Corporation's financial statements);

(xiv) review before release relevant public disclosure documents containing audited or unaudited financial information, including annual and interim earnings press releases, prospectuses, the Annual Information Form, and the Management's Discussion and Analysis disclosure;

(xv) review, in conjunction with the Human Resources & Compensation Committee, the appointment of the chief financial officer;

(xvi) inquire into and determine the appropriate resolution of conflicts of interest in respect of audit, finance or risk matters between or among an officer, Director, shareholder, the internal auditors, or the external auditors, which are properly directed to the Committee by the Chair of the Board, the Board, a shareholder, the internal auditors, the external auditors, or the Corporation's management; and

(xvii) as deemed necessary by the Committee, inquire into and examine matters relating to the financial affairs of the Corporation, its subsidiaries or affiliates, or any of them, including the review of subsidiary or affiliate Audit Committee reports.

C. DUTIES AND RESPONSIBILITIES RELATED TO FINANCIAL REPORTING PROCESSES AND INTERNAL CONTROLS

The Committee shall:

(i) review the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors, management, and the internal auditor;

(ii) review with management the Corporation's administrative, operational and accounting internal controls, including controls and security of the computerized information systems, and evaluate whether the Corporation is operating in accordance with prescribed policies, procedures and the Statement on Business Conduct;

(iii) annually or more frequently if deemed necessary, meet separately with the external auditor, the head of the internal audit group and management, to review issues and matters of concern respecting financial reporting processes and internal controls;

(iv) review with management and the external auditors any reportable conditions, material weaknesses and significant deficiencies affecting internal control;

(v) establish and maintain free and open means of communication between and among the Committee, the external auditors, the internal auditor and management;

(vi) review at least annually with the internal auditor the Corporation's internal control procedures, and the scope and plans for the work of the internal audit group; and

(vii) review the adequacy of resources of the internal auditor and ensure that the internal auditor has unrestricted access to all functions, records, property and personnel of the Corporation and inform the internal auditors and management that the internal auditors shall have unfettered access directly to the Committee at all times, as well as the Committee to the internal auditors.

D. DUTIES AND RESPONSIBILITIES RELATED TO FINANCE.

The Committee shall:

(i) review and as required, approve or recommend for approval to the Board, prospectuses and documents, where practicable, which may be incorporated by reference into a prospectus;

(ii) review the issuance of equity or debt securities by the Corporation, and if deemed appropriate, authorize the filing with securities regulatory authorities of any prospectus, prospectus supplement or other documentation relating thereto; and

(iii) review and recommend for approval to the Board the annual management information circular with respect to matters related to the auditor, affecting the capital of the Corporation or principal risks to be managed by the Corporation.

E. DUTIES AND RESPONSIBILITIES RELATED TO RISK MANAGEMENT

The Committee shall review at least annually with senior management, internal counsel and, as necessary, external counsel and the Corporation's internal and external auditors:

(a) the Corporation's method of reviewing major risks inherent in the Corporation's businesses, facilities, and strategic directions, including the Corporation's risk management and evaluation process (in respect of risk management evaluations and guidelines relating to environment, health and safety matters, the Committee shall consult with and, as deemed necessary, review the recommendations of the Environment, Health & Safety Committee);

(b) the strategies and practices applicable to the Corporation's assessment, management, prevention and mitigation of risks (including the foreign currency and interest rate risk strategies, counterparty credit exposure, the use derivative instruments, insurance and adequacy of tax provisions);

(c) the Corporation's annual insurance report including the risk retention philosophy and resulting uninsured exposure, if any; and

(d) the loss prevention policies, risk management programs, disaster response and recovery programs, corporate liability protection programs for Directors and officers, and standards and accountabilities of the Corporation in the context of competitive and operational considerations.

F. OTHER DUTIES OF AUDIT, FINANCE & RISK COMMITTEE

The Committee shall, as required, or as deemed necessary by the Committee:

(i) review senior management's expense report summaries of the officers and Directors of the Corporation, and review senior management's report summaries concerning corporate aircraft usage;

(ii) meet separately with senior management, the internal auditors, the external auditors and, as is appropriate, internal and external legal counsel and independent advisors in respect of issues not elsewhere listed concerning any other audit, finance and risk matters;

(iii) review incidents or alleged incidents as reported by senior management, audit services, the external auditor, the Corporate Secretary, the law department, or otherwise of fraud, illegal acts and conflicts of interest;

(iv) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

(v) report to the Board after each Committee meeting, as required during the year, with respect to the Committee's activities and recommendations;

(vi) address any other matter properly referred to the Committee by the Chair of the Board, the Board, a Director, the internal auditors, the external auditors, the CEO, or the management of the Corporation or any other matter as may be required under stock exchange rules or by law;

(vii) in conjunction with the Governance Committee, conduct an annual performance evaluation of the Committee; and

(viii) the Committee shall, in conjunction with Management, coordinate the performance of its duties concerning:

(a) the external auditor;

(b) audits and financial reporting;

(c) financial reporting processes and internal controls;

(d) finance;

(e) risk management; and

(f) with any audit committee of a subsidiary corporation, respecting the independence of such subsidiary directors and managing to ensure efficiency, effectiveness and consistency of approach with such subsidiary.

VIII. COMMITTEE TIMETABLE

The major annual activities of the Committee shall be outlined in an annual schedule.

IX. DELEGATION TO SUBCOMMITTEE

The Committee may, in its discretion, delegate all or a portion of its duties and responsibilities to a subcommittee of the Committee. The Committee may, in its discretion, delegate to one or more of its members the authority to pre-approve any audit or non-audit services to be performed by the external auditors, provided that any such approvals are presented to the Committee at its next scheduled meeting.

DATE	Terms of Reference	PROPOSED AGENDA
January or February	B(iii),(ix),(x),(xi)	• Review Annual Financial Results
	B(iii)	• Recommend Financial Statements for Enbridge Inc. (ENB) and Enbridge Pipelines Inc. (EP Inc.)
	B(xiv)	• Recommend News Release
	A(viii) B(ii),(vi),(vii) B(viii), (xiii)	• Review External Auditor's Letter to Audit, Finance & Risk Committee (including review of quality and appropriateness of Company's accounting principles and controls, and perception of Company's accounting personnel)
	B(v)	• Review Management's approach to earnings releases and info provided to analysts
		• Review Subsidiary Audit Committee Confirmations
	A(i)	• Recommend Appointment of Auditors
		Recurring:
	A(iii)	• Pre-approval of auditor engagements
	E(i)	• Review Financial Risk Management Report
	C(i),(iii),(iv)	• Review audit and financial reporting issues, and internal controls with external auditors
February	D(i)	• Recommend Annual Information Form for ENB and EP Inc. (and Form 40-F filing as in U.S. for ENB)
	D(iii)	• Recommend Form of Proxy and Management Information Circular
	B(iii), D(i)	• Recommend MD&A

DATE	Terms of Reference	PROPOSED AGENDA
May	B(iv),(ix),(x),(xi) B(xiv) E(i)	• Review First Quarter Financial Results and MD&A • Recommend Interim Report / News Release • Review Insurance Report (including loss prevention policies, disaster response and recovery programs, liability protection programs for D&O)
	F(i)	• Review Senior Officers' Expense Reports
	F(i)	• Chair review of CEO Expense Reports • Review Major Contracts
	B(viii)	• Review Pension Plan Summary Report Recurring:
	A(iii) E(i) C(i),(iii),(iv)	• Pre-approval of auditor engagements • Review Financial Risk Management Report • Review audit and financial reporting issues, and internal controls with external auditors
July	B(iv),(ix),(x),(xi) B(xiv) B(ix),C(iii)(vi),(vii)	• Review Second Quarter Financial Results and MD&A • Recommend Interim Report/News Release • Review Audit Services: • Letter re: Employment Entitlements, Tax Deductions & Remittances • Report for year ended June 30 • Plan for next year
	A(i),(ii),(iv),(v) A(vii), B(i)	• Review External Auditors: • Engagement Letter (including auditor independence report) • Audit Plan (including auditor quality control procedures)
	A(ii)	• Recommend External Audit Fees, and Review Engagements and Services other than as Shareholders' Auditors
	E(i)	• Review Corporate Risk Assessment Report • Review next year's Committee Meeting Schedule and Agenda Recurring:
	A(iii) E(i) C(i),(iii),(iv)	• Pre-approval of auditor engagements • Review Financial Risk Management Report • Review audit and financial reporting issues, and internal controls with external auditors
November	B(iv),(ix),(x),(xi) B(xiv)	• Review Third Quarter Financial Results and MD&A • Recommend Interim Report/News Release
	E(i)	• Review Tax Status Report
	F(vii)	• Annual Performance Evaluation of AFRC
	F(i)	• Chair Review of CEO Expense Report Recurring:
	A(iii) E(i) C(i),(iii),(iv)	• Pre-approval of auditor engagements • Review Financial Risk Management Report • Review audit and financial reporting issues, and internal controls with external auditors
December	B(iii)	• Review Annual Financial Statement Disclosure
	B(ii)	• Review Management letter to Audit, Finance & Risk Committee
	C(ii)	• Review with Management the Corporation's admin, operational and accounting internal controls and security of IT systems
	B(iii), D(i)	• Review Draft MD&A

Exhibit 99.4



ENBRIDGE INC.
CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2007

MANAGEMENT'S REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

Financial Reporting

Management is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

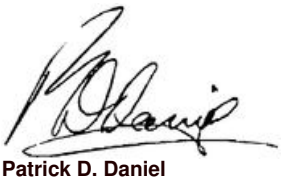
The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit, Finance & Risk Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2007.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.



Patrick D. Daniel
President & Chief Executive Officer



J. Richard Bird
Executive Vice President &
Chief Financial Officer

February 20, 2008

INDEPENDENT AUDITORS' REPORT

TO THE SHAREHOLDERS OF ENBRIDGE INC.

We have completed integrated audits of the consolidated financial statements and internal control over financial reporting of Enbridge Inc. as at December 31, 2007 and 2006 and an audit of its 2005 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Enbridge Inc. as at December 31, 2007 and December 31, 2006, and the related consolidated statements of earnings, comprehensive income, shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2007 and for each of the years in the two year period then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company's financial statements for the year ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exits, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2007 based on criteria established in Internal Control — Integrated Framework issued by the COSO.



Chartered Accountants
Calgary, Alberta, Canada

February 20, 2008

Comments by Auditors for U.S. Readers on Canada – U.S. Reporting Differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the changes described in note 2 to the consolidated financial statements. Our report to the shareholders dated February 20, 2008 is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the Independent Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.



Chartered Accountants
Calgary, Alberta, Canada

February 20, 2008

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of dollars, except per share amounts)

Year ended December 31,	**2007**	2006	2005
Revenues			
Commodity sales	**9,536.4**	8,264.5	6,193.5
Transportation	**2,115.5**	2,095.1	1,938.1
Energy services	**267.5**	284.9	321.5
	11,919.4	10,644.5	8,453.1
Expenses			
Commodity costs	**9,009.5**	7,824.6	5,728.4
Operating and administrative	**1,163.7**	1,084.2	1,057.6
Depreciation and amortization	**596.9**	587.4	575.3
	10,770.1	9,496.2	7,361.3
	1,149.3	1,148.3	1,091.8
Income from Equity Investments	**167.8**	180.3	116.8
Other Investment Income *(Note 21)*	**195.1**	107.8	142.4
Interest Expense *(Note 12)*	**(550.0)**	(567.1)	(539.2)
	962.2	869.3	811.8
Non-Controlling Interests	**(45.9)**	(54.7)	(27.6)
	916.3	814.6	784.2
Income Taxes *(Note 19)*	**(209.2)**	(192.3)	(221.3)
Earnings	**707.1**	622.3	562.9
Preferred Share Dividends	**(6.9)**	(6.9)	(6.9)
Earnings Applicable to Common Shareholders	**700.2**	615.4	556.0
Earnings per Common Share *(Note 15)*	**1.97**	1.81	1.65
Diluted Earnings per Common Share *(Note 15)*	**1.95**	1.79	1.63

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of dollars)

Year ended December 31,	**2007**	2006	2005
Earnings	**707.1**	622.3	562.9
Other Comprehensive Income/(Loss)			
Change in unrealized gains on cash flow hedges, net of tax	**96.4**	–	–
Reclassification to earnings of realized cash flow hedges, net of tax	**(6.7)**	–	–
Other comprehensive gain/(loss) from equity investees	**(19.8)**	–	–
Non-controlling interest in other comprehensive income	**4.9**	–	–
Change in foreign currency translation adjustment	**(447.1)**	87.6	(193.3)
Change in unrealized gains on net investment hedges, net of tax	**174.9**	(51.6)	161.3
Other Comprehensive Loss	**(197.4)**	36.0	(32.0)
Comprehensive Income *(Note 2)*	**509.7**	658.3	530.9

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Preferred Shares *(Note 15)*	**125.0**	125.0	125.0
Common Shares *(Note 15)*			
Balance at beginning of year	**2,416.1**	2,343.8	2,282.4
Common shares issued	**566.4**	–	6.8
Dividend reinvestment and share purchase plan	**17.7**	18.4	14.6
Shares issued on exercise of stock options	**26.3**	53.9	40.0
Balance at End of Year	**3,026.5**	2,416.1	2,343.8
Contributed Surplus			
Balance at beginning of year	**18.3**	10.0	5.4
Stock-based compensation	**8.9**	10.5	5.5
Options exercised	**(1.5)**	(2.2)	(0.9)
Balance at End of Year	**25.7**	18.3	10.0
Retained Earnings			
Balance at beginning of year	**2,322.7**	2,098.2	1,840.9
Earnings applicable to common shareholders	**700.2**	615.4	556.0
Cumulative impact of change in accounting policy *(Note 2)*	**(47.0)**	–	–
Dividend reclassification adjustment *(Note 8)*	**–**	–	51.2
Common share dividends	**(452.3)**	(403.1)	(361.1)
Dividends paid to reciprocal shareholder	**13.7**	12.2	11.2
Balance at End of Year	**2,537.3**	2,322.7	2,098.2
Accumulated Other Comprehensive Loss *(Note 17)*			
Balance at beginning of year	**(135.8)**	(171.8)	(139.8)
Cumulative impact of change in accounting policy *(Note 2)*	**48.2**	–	–
Other comprehensive (loss)/income	**(197.4)**	36.0	(32.0)
Balance at End of Year	**(285.0)**	(135.8)	(171.8)
Reciprocal Shareholding *(Note 8)*			
Balance at beginning of year	**(135.7)**	(135.7)	(135.7)
Participation in common shares issued	**(18.6)**	–	–
Balance at End of Year	**(154.3)**	(135.7)	(135.7)
Total Shareholders' Equity	**5,275.2**	4,610.6	4,269.5
Dividends Paid per Common Share	**1.2300**	1.1500	1.0375

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Operating Activities			
Earnings	**707.1**	622.3	562.9
Depreciation and amortization	**596.9**	587.4	575.3
Unrealized losses on derivative instruments	**32.3**	–	–
Equity earnings less than/(in excess of) cash distributions	**(35.2)**	(54.2)	63.3
Gain on reduction of ownership interest	**(33.9)**	–	(29.0)
Future income taxes	**40.8**	(21.0)	108.1
Non-controlling interests	**45.9**	54.7	27.6
Other	**4.1**	(18.2)	(7.3)
Changes in operating assets and liabilities *(Note 22)*	**20.7**	126.7	(353.9)
	1,378.7	1,297.7	947.0
Investing Activities			
Acquisitions *(Note 5)*	**–**	(101.4)	(88.6)
Long-term investments	**(20.3)**	(362.3)	(89.9)
Additions to property, plant and equipment	**(2,299.2)**	(1,185.3)	(724.1)
Affiliate loans, net	**15.6**	28.0	0.7
Change in construction payable	**48.0**	41.0	25.4
	(2,255.9)	(1,580.0)	(876.5)
Financing Activities			
Net change in short-term borrowings and short-term debt	**74.5**	(78.7)	(125.1)
Net change in non-recourse credit facilities	**43.1**	57.7	11.0
Long-term debt issues	**1,342.2**	1,125.0	1,020.1
Long-term debt repayments	**(634.5)**	(400.0)	(536.9)
Non-recourse long-term debt issues	**14.4**	2.8	6.8
Non-recourse long-term debt repayments	**(58.8)**	(60.5)	(85.1)
Contributions from/(distributions to) non-controlling interests	**(18.2)**	(31.3)	1.4
Common shares issued	**600.7**	63.1	53.7
Preferred share dividends	**(6.9)**	(6.9)	(6.9)
Common share dividends	**(452.3)**	(403.1)	(361.1)
	904.2	268.1	(22.1)
Increase/(Decrease) in Cash and Cash Equivalents	**27.0**	(14.2)	48.4
Cash and Cash Equivalents at Beginning of Year	**139.7**	153.9	105.5
Cash and Cash Equivalents at End of Year	**166.7**	139.7	153.9

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(millions of dollars)

Year ended December 31,	**2007**	2006
Assets		
Current Assets		
Cash and cash equivalents	**166.7**	139.7
Accounts receivable and other	**2,388.7**	2,045.6
Inventory	**709.4**	868.9
	3,264.8	3,054.2
Property, Plant and Equipment, net *(Note 6)*	**12,597.6**	11,264.7
Long-Term Investments *(Note 8)*	**2,076.3**	2,299.4
Deferred Amounts and Other Assets *(Note 9)*	**1,182.0**	924.5
Intangible Assets *(Note 10)*	**212.0**	241.5
Goodwill *(Note 11)*	**388.0**	394.9
Future Income Taxes *(Note 19)*	**186.7**	200.1
	19,907.4	18,379.3
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-term borrowings	**545.6**	807.9
Accounts payable and other	**2,213.8**	1,723.8
Interest payable	**89.1**	95.1
Current maturities of long-term debt *(Note 12)*	**605.2**	537.0
Current maturities of non-recourse debt *(Note 13)*	**61.1**	60.1
	3,514.8	3,223.9
Long-Term Debt *(Note 12)*	**7,729.0**	7,054.0
Non-Recourse Long-Term Debt *(Note 13)*	**1,508.4**	1,622.0
Other Long-Term Liabilities	**253.9**	91.1
Future Income Taxes *(Note 19)*	**975.6**	1,062.5
Non-Controlling Interests *(Note 14)*	**650.5**	715.2
	14,632.2	13,768.7
Shareholders' Equity		
Share capital		
Preferred shares *(Note 15)*	**125.0**	125.0
Common shares *(Note 15)*	**3,026.5**	2,416.1
Contributed surplus	**25.7**	18.3
Retained earnings	**2,537.3**	2,322.7
Accumulated other comprehensive loss *(Note 17)*	**(285.0)**	(135.8)
Reciprocal shareholding *(Note 8)*	**(154.3)**	(135.7)
	5,275.2	4,610.6
Commitments and Contingencies *(Note 24)*	**19,907.4**	18,379.3

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

Approved by the Board of Directors:



David A. Arledge
Chair



David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five operating segments: Liquids Pipelines, Gas Pipelines, Sponsored Investments, Gas Distribution and Services and International. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines includes the Canadian common carrier pipeline and feeder pipelines that transport crude oil and other liquid hydrocarbons including the Enbridge System, the Athabasca System, Spearhead Pipeline and a proportionately consolidated investment in the Olympic Pipeline.

GAS PIPELINES

Gas Pipelines consists of proportionately consolidated investments in natural gas pipelines including the U.S. portion of the Alliance Pipeline, Vector Pipeline and transmission and gathering pipelines in the Gulf of Mexico.

SPONSORED INVESTMENTS

Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP) and Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership) as well as Enbridge Income Fund (EIF).

The Partnership transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and natural gas liquids. EIF is a publicly traded income fund whose primary operations include a 50% interest in the Canadian portion of the Alliance Pipeline and a crude oil and liquids pipeline and gathering system.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of natural gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, and the Company's proportionately consolidated investment in Aux Sable, a natural gas fractionation and extraction business.

The Company's commodity marketing businesses are also included in Gas Distribution and Services. These businesses manage the Company's volume commitments on Alliance and Vector Pipelines as well as offer commodity storage, transport, and supply management services.

INTERNATIONAL

The Company's International business consists of investments in two energy-delivery businesses, Compañía Logística de Hidrocarburos CLH, S.A. (CLH) in Spain and Oleoducto Central S.A. (OCENSA) in Colombia.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). 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 27. Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the financial statements. Actual results could differ from these estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of joint ventures. EIF is consolidated in the accounts of the Company because it is a variable interest entity. The Company is the primary beneficiary of EIF through a combination of a 41.9% equity interest and a preferred unit investment. Investments in entities which are not subsidiaries or joint ventures, but over which the

Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for according to their classification as financial assets (see Financial Instruments). All long-term investments are assessed for impairment if the Company identifies an event indicative of possible impairment.

REGULATION

Certain of the Company's Liquids Pipelines, Gas Pipelines and Gas Distribution and Services businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Energy Resources Conservation Board in Alberta (ERCB), New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. In the absence of rate regulation, the Company would not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. Long-term regulatory assets are recorded in Deferred Amounts and Other Assets and current regulatory assets are recorded in Accounts Receivable and Other. Regulatory liabilities are recorded in Accounts Payable and Other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, the Company would capitalize only the interest component; therefore, the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

With the approval of the regulator, Enbridge Gas Distribution (EGD) capitalizes a percentage of certain operating costs into the rate base. EGD is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such costs may be charged to current earnings.

Contributions made to the defined benefit pension plan for the regulated operations of Gas Distribution and Services are expensed as paid, consistent with the recovery of such costs in rates. Canadian GAAP requires pension costs and obligations for defined benefit pension plans to be determined using the projected benefit method and charged to earnings as services are rendered.

The cost of providing post-employment benefits other than pensions (OPEB) for the regulated operations of Gas Distribution and Services is expensed when paid, consistent with the recovery of such costs in rates.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed. Customer credit worthiness is assessed before agreements are signed. Certain operations are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts, resulting in the recognition of regulatory assets and liabilities.

For the rate-regulated portion of the Company's main Canadian crude oil pipeline system, revenue is recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Certain Liquids Pipelines revenues are recognized under the terms of a committed 30-year delivery contract rather than the cash tolls received.

For rate-regulated operations in Gas Pipelines and Sponsored Investments, transportation revenues include amounts related to expenses recognized in the financial statements that are expected to be recovered from shippers in future tolls. Revenue is recognized in a given period for tolls received to the extent that expenses are incurred. Differences between the recorded transportation revenue and actual toll receipts give rise to receivable or payable balances.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the regulator. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. For the non-regulated portion of Gas Distribution and Services operations, delivery or service performance only takes place when there is a sales contract in place specifying delivery volumes or services required and sales prices.

FINANCIAL INSTRUMENTS

The Company classifies financial assets as either held for trading, held to maturity, loans and receivables or available for sale. The Company classifies financial liabilities as either held for trading or other financial liabilities.

Financial assets and liabilities that are "held for trading" are measured at fair value with changes in fair value recognized in earnings, except for derivatives that are designated as, and determined to be, effective hedging instruments, whose fair value is recorded in Other Comprehensive Income (OCI).

Financial assets that are "available for sale" are measured at fair value with changes in those fair values recorded in OCI. Financial assets that are "held to maturity" and "loans and receivables" and financial liabilities that are "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Other investments in entities which are not subsidiaries or joint ventures, and where the Company does not exercise significant influence, are classified as held to maturity, loans and receivables or available for sale. "Available for sale" investments are measured at fair value with changes in those fair values recorded in OCI. Where actively quoted prices are not available, these investments are carried at amortized cost. "Held to maturity" investments and "loans and receivables" are measured at amortized cost.

Cash and cash equivalents are designated as "held for trading" and are measured at carrying value which approximates fair value due to the short-term nature of these instruments. Accounts receivable and other are designated as "loans and receivables". Short-term borrowings, accounts payable and other, interest payable, long-term debt and non-recourse long-term debt are designated as "other financial liabilities".

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

Hedges

The Company uses derivatives and non-derivative financial instruments to manage changes in commodity prices, foreign currency exchange rates and interest rates. Hedge accounting is optional and it requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction.

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in commodity prices, foreign currency exchange rates and interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in OCI and reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in

earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period they occur.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability ceases to be remeasured at fair value and the fair value adjustment is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

The Company uses net investment hedges to manage the carrying values of U.S. dollar and euro denominated foreign investments. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated Other Comprehensive Income or Loss (AOCI) are recognized in earnings when there is a reduction of the hedged net investment resulting from a sale of ownership interests.

Non-Hedge Derivatives

The Company does not use derivative instruments for speculative purposes. However, if a derivative instrument is not an effective hedge for accounting purposes or is not designated as hedging item, changes in the fair value are recorded in current period earnings.

INCOME TAXES

For non-regulated operations, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The regulated activities of the Company recover income tax expense based on the taxes payable method when prescribed by regulators or in ratemaking agreements that are subject to regulatory approval. As a result, rates do not include the recovery of future income taxes related to temporary differences and the Company does not record future income tax assets or liabilities related to these differences. The Company expects that all unrecorded future income taxes will be recovered in rates when they become payable.

FOREIGN CURRENCY TRANSLATION

The Company's U.S. dollar operations are primarily self-sustaining. The Company also holds a self-sustaining euro equity investment in CLH. Self-sustaining operations are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates, with revenues and expenses translated using monthly average rates. Gains and losses arising on translation of these operations are included in the cumulative translation adjustment component of AOCI.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term deposits with a term to maturity of three months or less when purchased.

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded at the quarterly prices approved by the OEB in the determination of customer sales rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred for future refund or collection as approved by the OEB. Other inventory, consisting primarily of commodities held in storage, is recorded at the lower of cost and net realizable value.

PROPERTY, PLANT AND EQUIPMENT

Expenditures for construction, expansion, major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit. The Company capitalizes interest incurred during construction. For rate regulated assets, if approved, an allowance for equity funds used during construction is capitalized at rates authorized by the regulatory authorities. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates, contractual receivables under the terms of long-term delivery contracts, derivative financial instruments as well as pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation contracts which are amortized on a straight-line basis over the expected lives of the contracts.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. Goodwill is not subject to amortization but is tested for impairment at least annually and written down to fair value if impairment occurs.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized as long-term liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For certain of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

Depreciation expense for Gas Distribution and Services operations includes a provision for AROs at rates approved by the regulator. Actual costs incurred are charged to accumulated depreciation in accordance with regulatory treatment.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method and are charged to earnings as services are rendered, except for the regulated operations of Gas Distribution and Services, where contributions made to the plan are expensed as paid consistent with the recovery of such costs in rates. For defined contribution plans, contributions made by the Company are expensed.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values. Adjustments arising from plan amendments and the transitional amounts recognized on adoption of the accounting standard are amortized on a straight-line basis over the average remaining service period of the employees active at the date of amendment or transition. The excess of the net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of the active employees.

The Company also provides post-employment benefits other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants. The cost of such benefits is accrued during the years employees render service, except for the regulated operations of Gas Distribution and Services where the cost of providing these benefits is expensed as paid, consistent with the recovery of such costs in rates.

STOCK BASED COMPENSATION

Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at fair value at the grant date and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility with a corresponding credit to contributed surplus. Balances in contributed surplus are transferred to share capital when the options are exercised.

Performance Stock Units (PSUs) vest at the completion of a three-year term and Restricted Stock Units vest at the completion of a 35-month term; both are settled in cash. During the term, a liability and expense are recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSU's is also dependent on the Company's current performance relative to performance targets set out under the plan.

COMPARATIVE AMOUNTS

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

2. CHANGES IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1530 *Comprehensive Income*, Section 3251 *Equity*, Section 3855 *Financial Instruments – Recognition and Measurement*, Section 3861 *Financial Instruments – Disclosure and Presentation* and Section 3865 *Hedges*. In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated. Prior period unrealized gains and losses related to the Company's foreign currency translation adjustments and net investment hedges are now included in AOCI.

The adoption of the new standards did not impact the Company's earnings or cash flows.

Comprehensive Income and Equity

The new standards introduce comprehensive income, which consists of earnings and OCI. The Company's consolidated financial statements now include a Statement of Comprehensive Income. The Company's OCI is primarily comprised of the effective portion of changes in unrealized gains and losses related to cash flow hedges; the Company's share of the OCI of equity investees; and unrealized foreign exchange gains and losses related to self-sustaining foreign investments and the net investment hedges of those foreign investments.

The Company now presents a Consolidated Statement of Shareholders' Equity, which includes the change for each component of shareholders' equity. The cumulative changes in OCI are recorded in AOCI, a separate component of shareholders' equity. The cumulative translation adjustment, previously presented as a separate component of shareholders' equity, is now presented as a component of AOCI. The components of AOCI are presented in Note 17.

Financial Instruments

CICA Handbook Section 3855 establishes recognition and measurement criteria for financial instruments. The new standard requires that, generally, all financial instruments are recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as "held to maturity", "held for trading", "available for sale" or "loans and receivables" as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the carrying value of the Company's financial instruments has not changed. The methods by which the Company determines the fair value of its financial instruments have also not changed as a result of adopting this standard.

Impact on Adoption

The adoption of the new standards resulted in the following adjustments on January 1, 2007:

(millions of dollars) Increase/(Decrease)	Assets	Liabilities and Equity
Accounts Receivable and Other[1,2]	5.4	–
Deferred Amounts and Other Assets[1,2,3,4]	55.3	–
Long-Term Investments[1]	(57.3)	–
Accounts Payable and Other[2]	–	57.6
Long-Term Debt[3]	–	(52.7)
Other Long-Term Liabilities[1,2,4]	–	42.5
Future Income Taxes[1]	–	(18.9)
Non-Controlling Interests[1]	–	(26.3)
Accumulated Other Comprehensive Income[1]	–	48.2
Retained Earnings[1]	–	(47.0)
	3.4	3.4

1 *As a result of the new standards for cash flow hedges, the Company recognized unrealized net gains related to interest rate, foreign exchange and commodity hedges. The Company adjusted both deferred amounts and retained earnings for historical fair value adjustments related to certain cash flow hedges.*

2 *The Company recorded a regulatory liability due to the recognition of fixed price power contracts offset by unrealized financial instrument losses.*

3 *The Company reclassified unamortized deferred financing fees from deferred amounts and other assets to long-term debt as a result of adopting the new standards.*

4 *Relates to the recognition of gas purchase hedges for the regulated gas distribution businesses at January 1, 2007.*

FUTURE ACCOUNTING POLICY CHANGES

Capital Disclosures and Financial Instruments – Disclosures and Presentation

Effective January 1, 2008, the Company will adopt new accounting standards for Capital Disclosures (CICA Handbook Section 1535) and Financial Instruments – Disclosures and Presentation (CICA Handbook Sections 3862 and 3863).

Under Section 1535, the Company will disclose its objectives, policies and procedures for managing capital, any summary quantitative data about what the Company manages as capital, whether the Company has complied with any externally imposed capital requirements and, if the Company has not complied with them, any consequences of non-compliance with these capital requirements.

The new Sections 3862 and 3863 replace Section 3861 *Financial Instruments – Disclosure and Presentation*. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements will expand disclosure about the significance of financial instruments for the Company's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks.

Inventories

The CICA issued Section 3031 *Inventories* effective January 1, 2008 which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards (IFRS). This standard is not expected to materially impact the Company's financial statements.

Accounting for the Effects of Rate Regulation

In August 2007, the Canadian Accounting Standards Board (AcSB) published its decision with respect to rate regulated operations. The AcSB decided to retain much of the existing guidance related to rate-regulated operations however, the exemption from the requirement to record future income taxes, as currently provided in CICA Handbook Section 3465, *Income Taxes*, and the exemption from CICA Handbook Section 1100, *Generally Accepted Accounting Principles,* will be removed, effective January 1, 2009. The Company will adopt these changes on January 1, 2009 and the principal effect will be the recognition of future income tax liabilities on the balance sheet, offset equally by regulatory assets.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation where the rates approved by the regulator are designed to recover the costs of providing the products and services. The Company's significant regulated businesses and related accounting impacts are described below.

Enbridge System

The primary business activities of the Enbridge System are subject to regulation by the NEB. Tolls are set based on agreements with customers and are filed with the NEB for approval. The incentive tolling settlement (ITS) is effective from January 1, 2005 to December 31, 2009 and defines the methodology for calculation of tolls and the revenue requirement on the core component of the Enbridge System in Canada. Toll adjustments, for variances from requirements defined in the ITS, are filed annually with the regulator for approval.

Athabasca Pipeline

Athabasca Pipeline is regulated by the ERCB. Tolls are established based on long-term transportation agreements with individual shippers and taxes are recorded using the taxes payable method.

Vector Pipeline

Vector Pipeline is an interstate natural gas pipeline with a FERC approved tariff establishing rates, terms and conditions governing its service to customers. Rates are determined using a cost of service methodology. Tariff changes may only be implemented upon approval by the FERC. Tolls include a return on equity component of 10.75% (2006 – 10.75%) after tax.

Alliance Pipeline

The US portion of the Alliance Pipeline (Alliance) is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on Alliance entered into 15-year transportation contracts expiring in December 2015, with a cost of service toll methodology. Toll adjustments are filed annually with the regulator. The tolls include a return on equity component of 10.88% (2006 – 10.85%) after tax for the US portion and 11.26% (2006 – 11.25%) after tax for the Canadian portion. Alliance tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. EGD's rates are set under a cost of service methodology with revenues charged to recover EGD's forecast costs and to earn a rate of return on common equity. Applications for changes to rates are made annually and are submitted for approval by the OEB.

Forecast costs include gas commodity and transportation, operation and maintenance, depreciation, municipal taxes, interest and income taxes. The rate base is the average investment in permitted assets used in gas distribution, storage and transmission and an allowance for working capital. EGD's 2007 approved rate of return on rate base was 7.58% (2006 – 7.74%) after tax, and the approved rate of return on common equity was 8.39% (2006 – 8.74%) after tax based on a 36% (2006 – 35%) deemed common equity.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and follows a cost of service tolling methodology. An application for rate adjustments is filed annually for EUB approval. EGNB's rate of return on rate base was 9.70% (2006 – 9.78%) after tax and the approved rate of return on equity was 13.00% (2006 – 13.00%) after tax, based on equity which is capped at 50%.

REGULATORY RISK AND UNCERTAINTIES AFFECTING RECOVERY OR SETTLEMENT

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

FINANCIAL STATEMENT EFFECTS

To recognize the actions or expected actions of the regulator, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Accounting for rate-regulated entities has resulted in recording the following regulatory assets and liabilities:

(millions of dollars) December 31,	**2007**	2006	Estimated Settlement Period (years)	Earnings Impact[1] **2007**	Earnings Impact[1] 2006
Regulatory Assets/(Liabilities)					
Liquids Pipelines					
Enbridge System tolling deferrals[2]	**143.4**	166.2	1	**(22.8)**	(6.1)
Power purchase arrangements[3]	**(23.8)**	–	1-3	**(23.8)**	–
Gas Pipelines					
Deferred transportation revenue[4]	**181.4**	203.8	16-18	**5.9**	9.8
Transportation revenue adjustment[5]	**4.1**	9.3	1	**(2.6)**	(1.4)
Sponsored Investments					
Deferred transportation revenue[4]	**65.6**	47.4	18	**7.7**	7.3
Gas Distribution and Services					
EGNB regulatory deferral[6]	**117.7**	101.8	33	**10.3**	12.4
Class action lawsuit settlement[7]	**22.0**	22.0	2	**–**	13.5
Ontario hearing cost[8]	**8.1**	9.2	2	**(0.7)**	(1.7)
Purchased gas variance[9]	**(141.1)**	(127.4)	1	**(8.8)**	(99.3)
Unaccounted for gas variance[10]	**6.1**	(11.7)	1	**11.4**	(9.4)
Transactional services deferral[11]	**(8.8)**	(7.5)	1	**–**	–

1 *Represents the effect of rate regulation on after tax reported earnings.*

2 *Tolls on the Enbridge System are calculated in accordance with the ITS, System Expansion Program (SEP) II and the Terrace agreements and are established each year based on capacity, the allowed revenue requirement and the Terrace agreement. Where actual volumes shipped on the pipeline do not result in collection of the annual revenue requirement, a receivable is recognized and incorporated into tolls in the subsequent year. However, recovery is dependent on volumes shipped since each shipper is only responsible for their pro-rata share of the increase in tolls. In addition, other tolling deferrals occur in accordance with the various agreements.*

3 *The power purchase arrangements liability is the fair value of fixed price contracts and related financial instruments used to manage the mix of fixed and floating power costs (see Note 18).*

4 *Deferred transportation revenue is related to the cumulative difference between GAAP depreciation expense of Alliance and Vector Pipelines and depreciation expense included in the regulated transportation rates. The Company expects to recover this difference over a number of years when depreciation rates in the transportation agreements are expected to exceed the GAAP depreciation rates, for Alliance beginning in 2011 and ending in 2025 and for Vector beginning in 2008 and ending in 2023. This regulatory asset is not included in the rate base.*

5 *The transportation revenue adjustment is the cumulative difference between actual expenses of Alliance Pipeline US and estimated expenses included in transportation rates. The transportation revenue adjustment is recoverable under the long-term transportation agreements and is not included in the rate base.*

6 *A regulatory deferral account captures the difference between EGNB's distribution revenues and its cost of service revenue requirement during the development period. The regulatory deferral account balance will be amortized over a recovery period approved by the EUB commencing at the end of the development period, which is currently expected to end after 2040.*

7 *Class action lawsuit settlement deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. This amount is expected to be recovered in future periods.*

8 *Ontario hearing costs are incurred by EGD for the rate hearing process. EGD has historically been granted OEB approval for recovery of such hearing costs, generally within two years.*

9 *Purchased gas variance is the difference between the actual cost and the approved cost of gas reflected in rates. EGD has historically been granted approval for recovery or required refund of this variance within the year.*

10 *Unaccounted for gas variance represents the difference between the total gas distributed by EGD and the amount of gas billed or billable to ratepayers, to the extent it is different from the approved gas variance. EGD has deferred unaccounted for gas variance and has historically been granted approval for recovery or required refund of this amount in the subsequent year.*

11 *Transactional services deferral represents the ratepayer portion of excess earnings generated from optimization of storage and pipeline capacity. EGD has historically been required to refund the amount to ratepayers in the following year.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Future Income Taxes

In the absence of rate regulation, future income tax liabilities of $517.1 million (2006 – $584.0 million) associated with certain assets, primarily property, plant and equipment, would be recorded.

The Company has recorded net future income tax liabilities of $24.0 million (2006 – $32.9 million) related to certain regulatory asset/liability deferral accounts identified above. Accumulated future income tax assets of $55.6 million (2006 – $64.7 million) related to the remaining regulatory deferral accounts have not been recognized at December 31, 2007. In the absence of rate regulation, regulatory deferrals would not be recorded nor would the associated future income tax liabilities. As a result of these tax impacts, earnings during the year would increase by $62.2 million (2006 – $65.0 million).

Allowance For Funds Used During Construction and Other Capitalized Costs

With the pool method prescribed by regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2007, $82.2 million (2006 – $66.4 million) was included in gas mains, which are depreciated over the average service life of 25 years. In the absence of rate regulation, the majority of these costs would be charged to current earnings.

Pension Plans

Had pension costs and obligations been recognized, the net pension asset would have increased by $153.3 million at December 31, 2007 (2006 – $157.1 million) and earnings would have decreased by $1.1 million (2006 – $0.5 million).

Post-Employment Benefits Other than Pensions

In the absence of rate regulation, the cost of such benefits is accrued during the years employees render service. Had these costs been accrued, the net OPEB liability would have increased by $70.8 million (2006 – $67.1 million) and earnings would have decreased by $5.8 million (2006 – $5.5 million).

4. SEGMENTED INFORMATION

(millions of dollars) **Year ended December 31, 2007**	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	**1,090.9**	**321.3**	**270.3**	**10,227.1**	**9.8**	**–**	**11,919.4**
Commodity costs	**–**	**–**	**–**	**(9,009.5)**	**–**	**–**	**(9,009.5)**
Operating and administrative	**(426.5)**	**(87.4)**	**(79.2)**	**(535.9)**	**(14.2)**	**(20.5)**	**(1,163.7)**
Depreciation and amortization	**(155.8)**	**(83.5)**	**(74.8)**	**(277.0)**	**(0.8)**	**(5.0)**	**(596.9)**
	508.6	**150.4**	**116.3**	**404.7**	**(5.2)**	**(25.5)**	**1,149.3**
Income from equity investments	**(0.6)**	**–**	**96.5**	**8.8**	**64.1**	**(1.0)**	**167.8**
Other investment income	**15.5**	**23.4**	**38.8**	**28.0**	**39.1**	**50.3**	**195.1**
Interest and preferred share dividends	**(100.9)**	**(64.2)**	**(61.9)**	**(207.1)**	**–**	**(122.8)**	**(556.9)**
Non-controlling interest	**(1.3)**	**–**	**(38.4)**	**(6.2)**	**–**	**–**	**(45.9)**
Income taxes	**(134.1)**	**(39.9)**	**(54.4)**	**(44.1)**	**(2.9)**	**66.2**	**(209.2)**
Earnings applicable to common shareholders	**287.2**	**69.7**	**96.9**	**184.1**	**95.1**	**(32.8)**	**700.2**

(millions of dollars) Year ended December 31, 2006	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	1,048.1	345.9	254.7	8,981.6	14.2	–	10,644.5
Commodity costs	–	–	–	(7,824.6)	–	–	(7,824.6)
Operating and administrative	(391.2)	(96.0)	(67.7)	(485.8)	(18.2)	(25.3)	(1,084.2)
Depreciation and amortization	(153.4)	(87.5)	(71.9)	(269.1)	(0.9)	(4.6)	(587.4)
	503.5	162.4	115.1	402.1	(4.9)	(29.9)	1,148.3
Income from equity investments	(0.2)	–	111.5	17.0	52.2	(0.2)	180.3
Other investment income	3.2	9.2	2.9	17.8	45.2	29.5	107.8
Interest and preferred share dividends	(102.4)	(73.3)	(60.0)	(197.8)	–	(140.5)	(574.0)
Non-controlling interest	(1.6)	–	(48.0)	(5.1)	–	–	(54.7)
Income taxes	(128.3)	(37.1)	(34.7)	(55.8)	(9.3)	72.9	(192.3)
Earnings applicable to common shareholders	274.2	61.2	86.8	178.2	83.2	(68.2)	615.4

(millions of dollars) Year ended December 31, 2005	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	881.0	364.3	249.0	6,947.1	11.7	–	8,453.1
Commodity costs	–	–	–	(5,728.4)	–	–	(5,728.4)
Operating and administrative	(311.4)	(95.5)	(60.1)	(549.3)	(17.5)	(23.8)	(1,057.6)
Depreciation and amortization	(145.6)	(94.3)	(71.5)	(257.3)	(1.2)	(5.4)	(575.3)
	424.0	174.5	117.4	412.1	(7.0)	(29.2)	1,091.8
Income from equity investments	0.8	–	48.6	8.9	58.5	–	116.8
Other investment income	0.4	5.9	27.3	30.6	39.7	38.5	142.4
Interest and preferred share dividends	(96.5)	(81.9)	(61.8)	(178.8)	–	(127.1)	(546.1)
Non-controlling interest	(2.1)	–	(21.2)	(3.8)	(0.5)	–	(27.6)
Income taxes	(97.5)	(38.7)	(45.5)	(90.2)	(3.3)	53.9	(221.3)
Earnings applicable to common shareholders	229.1	59.8	64.8	178.8	87.4	(63.9)	556.0

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 1.

1 *Corporate includes new business development activities and investing and financing activities, including general corporate investments and financing costs not allocated to the business segments.*

TOTAL ASSETS

(millions of dollars)

December 31,	**2007**	2006
Liquids Pipelines	**5,334.6**	4,004.4
Gas Pipelines	**2,043.9**	2,297.0
Sponsored Investments	**2,688.1**	2,841.5
Gas Distribution and Services	**8,355.7**	7,635.4
International	**908.6**	917.2
Corporate	**576.5**	683.8
	19,907.4	18,379.3

ADDITIONS TO PROPERTY, PLANT AND EQUIPMENT

(millions of dollars)

December 31,	**2007**	2006	2005
Liquids Pipelines	**1,413.1**	428.8	258.6
Gas Pipelines	**200.4**	110.8	10.1
Sponsored Investments	**54.9**	33.4	15.5
Gas Distribution and Services	**609.4**	611.1	434.0
International and Corporate	**29.5**	23.4	5.9
	2,307.3	1,207.5	724.1

GEOGRAPHIC INFORMATION

Revenues[1]

(millions of dollars)

December 31,	**2007**	2006	2005
Canada	**8,337.0**	7,968.7	6,747.5
United States	**3,572.6**	2,661.6	1,693.9
Other	**9.8**	14.2	11.7
	11,919.4	10,644.5	8,453.1

1 Revenues are based on the country of origin of the product or services sold.

Property, Plant and Equipment

(millions of dollars)

December 31,	**2007**	2006
Canada	**10,031.2**	8,859.7
United States	**2,564.4**	2,401.8
Other	**2.0**	3.2
	12,597.6	11,264.7

5. ACQUISITIONS

On February 1, 2006, Enbridge acquired a 65% common share interest in the Olympic Pipeline Company for $112.7 million in cash. In 2005, the Company acquired interests in five other businesses for a total of $106.6 million, including $6.8 million paid in common shares of the Company.

(millions of dollars) Year ended December 31,	Olympic 2006	Combined 2005
Fair Value of Assets Acquired:		
Property, plant and equipment	107.0	66.6
Intangible assets	–	25.7
Other assets	5.0	0.7
Future income taxes	(6.1)	(16.3)
Other liabilities	(17.0)	(0.9)
	88.9	75.8
Goodwill	23.8	30.8
	112.7	106.6
Purchase Price:		
Cash (2006, net of $1.6 million cash acquired)	112.7	88.6
Contingent consideration	–	11.2
Shares issued	–	6.8
Deposit paid in 2005	(11.3)	–
	101.4	106.6

6. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars) **December 31, 2007**	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	**2.2%**	**2,688.4**	**1,259.9**	**1,428.5**
Pumping Equipment, Buildings, Tanks and Other	**3.7%**	**2,566.6**	**912.1**	**1,654.5**
Land and Right-of-Way	**1.8%**	**41.5**	**18.5**	**23.0**
Under Construction	**–**	**1,546.4**	**–**	**1,546.4**
		6,842.9	**2,190.5**	**4,652.4**
Gas Pipelines				
Pipeline	**3.7%**	**1,656.5**	**390.4**	**1,266.1**
Land and Right-of-Way	**2.7%**	**38.8**	**7.6**	**31.2**
Metering and Other	**4.6%**	**101.6**	**16.0**	**85.6**
Under Construction	**–**	**272.6**	**–**	**272.6**
		2,069.5	**414.0**	**1,655.5**
Sponsored Investments				
Pipeline	**4.2%**	**1,402.8**	**284.1**	**1,118.7**
Other	**7.6%**	**108.7**	**13.9**	**94.8**
		1,511.5	**298.0**	**1,213.5**
Gas Distribution and Services				
Gas Mains	**3.3%**	**2,748.9**	**708.7**	**2,040.2**
Gas Services	**3.6%**	**2,224.0**	**676.4**	**1,547.6**
Regulating and Metering Equipment	**3.7%**	**581.9**	**158.0**	**423.9**
Storage	**2.7%**	**246.4**	**61.0**	**185.4**
Computer Technology	**19.4%**	**185.2**	**81.6**	**103.6**
Other	**4.6%**	**310.6**	**106.5**	**204.1**
Under Construction	**–**	**495.7**	**–**	**495.7**
		6,792.7	**1,792.2**	**5,000.5**
International and Corporate – Other	**8.1%**	**113.0**	**37.3**	**75.7**
		17,329.6	**4,732.0**	**12,597.6**

(millions of dollars) December 31, 2006	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.3%	2,781.6	1,241.3	1,540.3
Pumping Equipment, Buildings, Tanks and Other	3.7%	2,501.3	874.1	1,627.2
Land and Right-of-Way	1.7%	40.1	18.4	21.7
Under Construction	–	304.8	–	304.8
		5,627.8	2,133.8	3,494.0
Gas Pipelines				
Pipeline	3.7%	1,999.7	397.0	1,602.7
Land and Right-of-Way	2.7%	46.3	8.0	38.3
Metering and Other	4.5%	128.0	20.1	107.9
Under Construction	–	64.2	–	64.2
		2,238.2	425.1	1,813.1
Sponsored Investments				
Pipeline	4.4%	1,372.8	219.2	1,153.6
Other	5.2%	83.8	9.6	74.2
		1,456.6	228.8	1,227.8
Gas Distribution and Services				
Gas Mains	4.2%	2,342.2	531.3	1,810.9
Gas Services	4.5%	1,933.6	523.6	1,410.0
Regulating and Metering Equipment	3.9%	624.5	153.9	470.6
Storage	2.7%	270.3	60.2	210.1
Computer Technology	18.1%	346.6	195.3	151.3
Other	2.6%	426.5	112.1	314.4
Under Construction	–	308.7	–	308.7
		6,252.4	1,576.4	4,676.0
International and Corporate – Other	7.0%	86.3	32.5	53.8
		15,661.3	4,396.6	11,264.7

7. JOINT VENTURES

Enbridge has joint venture interests in the following entities:

December 31,		**2007**	2006
(millions of dollars)	Ownership Interest		Net Assets
Liquids Pipelines			
Olympic Pipeline	65%	**97.8**	111.1
Other	30% - 50%	**54.8**	58.5
Gas Pipelines			
Alliance Pipeline US	50%	**364.3**	422.7
Vector Pipeline	60%	**408.4**	442.3
Enbridge Offshore Pipelines – various joint ventures	22% - 75%	**441.3**	517.4
Sponsored Investments			
Alliance Pipeline Canada	50%	**354.8**	357.7
Other	33% - 50%	**69.2**	56.4
Gas Distribution and Services			
Aux Sable	42.7%	**150.6**	178.7
Other	42.7% - 70%	**49.7**	55.3
		1,990.9	2,200.1

The following summarizes the impact of proportionately consolidating the joint ventures on the consolidated financial statements of Enbridge:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Earnings			
Revenues	**844.5**	939.4	1,402.5
Commodity costs	**(132.9)**	(184.8)	(608.2)
Operating and administrative	**(207.6)**	(257.2)	(320.7)
Depreciation and amortization	**(152.9)**	(164.8)	(162.3)
Interest expense	**(106.4)**	(110.8)	(117.1)
Other investment income	**6.6**	7.3	4.6
Proportionate share of earnings	**251.3**	229.1	198.8
Cash Flows			
Cash provided by operations	**312.0**	318.3	271.1
Cash used in investing activities	**(131.9)**	(59.5)	(13.4)
Cash used in financing activities	**(183.9)**	(258.9)	(268.0)
Proportionate share of decrease in cash and cash equivalents	**(3.8)**	(0.1)	(10.3)

(millions of dollars) December 31,	**2007**	2006
Financial Position		
Current assets	**146.0**	178.7
Property, plant and equipment, net	**2,913.1**	3,224.6
Deferred amounts and other assets	**277.6**	288.5
Current liabilities	**(139.8)**	(151.8)
Long-term debt	**(1,181.6)**	(1,315.4)
Other long-term liabilities	**(24.4)**	(24.5)
Proportionate share of net assets	**1,990.9**	2,200.1

8. LONG-TERM INVESTMENTS

(millions of dollars) December 31,	Ownership Interest	**2007**	2006
Equity Investments			
Liquids Pipelines			
Chicap Pipeline	22.8%	**17.2**	21.5
Sponsored Investments			
The Partnership	15.1%	**944.8**	1,105.5
Gas Distribution and Services			
Noverco Common Shares	32.1%	**11.6**	37.0
Other		**1.5**	1.4
International			
Compañía Logística de Hidrocarburos CLH, S.A.	25.0%	**626.4**	662.2
Corporate		**16.1**	17.1
Other Investments			
Gas Distribution and Services			
Noverco Preferred Shares		**181.4**	181.4
Fuel Cell Energy		**25.0**	25.0
International			
Oleoducto Central S.A.		**223.3**	223.3
Corporate			
Value Creation		**29.0**	25.0
		2,076.3	2,299.4

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the purchase date of $581.1 million at December 31, 2007 (2006 – $617.5 million). The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values and is amortized over the economic life of the assets. Consolidated retained earnings at December 31, 2007 includes undistributed earnings from equity investments of $5.0 million (2006 – $10.4 million).

THE PARTNERSHIP

The Company has a combined 15.1% ownership in EEP, through a 2.0% general partner interest, a 4.2% interest in Class B units, a 6.4% interest in Class C units and a 2.5% interest in EEP via a 17.2% investment in EEM, which owns 14.6% of EEP via its 100% interest in EEP's i-units. The Company recorded investment income from EEP of $130.4 million (2006 – $111.5 million) including dilution gains.

Although 82.8% of EEM is widely held, the Company has voting control and; therefore, consolidates EEM, including its investment in EEP of $456.4 million (2006 – $545.0 million). Net of non-controlling interest in EEM, the book value of the Company's investment in EEP is $566.7 million (2006 – $654.3 million.)

In the second quarter of 2007, EEP issued Class A and Class C partnership units. As Enbridge did not fully participate in these offerings, dilution gains net of tax and non-controlling interest of $11.8 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%.

In 2006, the Company acquired 5.4 million Class C units of EEP for $280.2 million. The Class C units have the same 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 are 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 and Class B unitholders, Class C units will convert into Class A units on a one-to-one basis. If approval of the conversion is not received, the Class C units will receive cash distributions equal to 115% of those paid to Class A unitholders.

NOVERCO

The Company owns a preferred share investment in Noverco of $181.4 million (2006 – $181.4 million), which is entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.34%. The fair value of the investment approximates its carrying value as its return is based on a floating rate.

The Company also owns an equity investment in the common shares of Noverco of $11.6 million (2006 – $37.0 million). Noverco owns an approximate 9.5% (2006 – 9.5%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.1% (2006 – 3.2%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $154.3 million (2006 – $135.7 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from the earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco. In 2007, the Company recorded equity investment earnings of $8.5 million (2006 – $16.8 million) related to its interest in Noverco.

In 2005, the Company reclassified $51.2 million in dividends paid to Noverco representing the reciprocal portion of dividends paid to Noverco from September 1, 1997 to December 31, 2004. The reclassification increased equity investments and retained earnings by $51.2 million.

CLH

The Company owns a 25% equity interest in CLH of $626.4 million (2006 – $662.2 million), a refined products transportation and storage company in Spain. In 2007, the Company recorded equity investment income from CLH of $64.1 million (2006 – $52.3 million).

OCENSA

The Company owns an investment in OCENSA, a crude oil export pipeline in Colombia of $223.3 million (US$160.2 million) (2006 – $223.3 million; US$160.2 million), which earns a fixed rate of return. The fair value of this investment is approximately $198.0 million (US$200.4 million) (2006 – $245.9 million; US$211.0 million), estimated using year-end market information.

9. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of dollars) December 31,	**2007**	2006
Regulatory deferrals	**428.2**	395.9
Contractual receivables	**152.0**	142.8
Long-term portion of derivative financial instruments	**329.0**	205.1
Pension asset	**72.3**	56.0
Deferred financing charges *(Note 2)*	**–**	52.7
Affiliate long-term note receivable (US$130.0 million) *(Note 23)*	**128.5**	–
Other	**72.0**	72.0
	1,182.0	924.5

At December 31, 2007, deferred amounts of $42.3 million (2006 – $146.8 million) were subject to amortization and are presented net of accumulated amortization of $23.2 million (2006 – $67.6 million). Amortization expense in 2007 was $3.6 million (2006 – $10.1 million; 2005 – $12.5 million).

10. INTANGIBLE ASSETS

(millions of dollars) **December 31, 2007**	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Transportation agreements	**4.2%**	**241.8**	**36.3**	**205.5**
Customer lists	**7.1%**	**8.3**	**1.8**	**6.5**
		250.1	**38.1**	**212.0**

(millions of dollars) December 31, 2006	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
Transportation agreements	4.2%	261.5	28.4	233.1
Customer lists	7.1%	9.8	1.4	8.4
		271.3	29.8	241.5

Amortization expense of $10.4 million was recorded for the year ended December 31, 2007 (2006 – $11.0 million; 2005 – $11.1 million).

11. GOODWILL

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	Consolidated
Balance at January 1, 2006	–	29.9	308.1	29.2	367.2
Olympic Pipeline acquisition	23.8	–	–	–	23.8
Foreign exchange and other	0.7	–	–	3.2	3.9
Balance at December 31, 2006	**24.5**	**29.9**	**308.1**	**32.4**	**394.9**
Foreign exchange and other	**(6.2)**	**(4.6)**	**–**	**3.9**	**(6.9)**
Balance at December 31, 2007	**18.3**	**25.3**	**308.1**	**36.3**	**388.0**

12. DEBT

(millions of dollars) December 31,	Weighted Average Interest Rate	Maturity	**2007**	2006
Liquids Pipelines				
Debentures	8.20%	2024	**200.0**	200.0
Medium-term notes	5.62%	2009 - 2036	**824.6**	824.6
Other (US$365.0 million; 2006 – nil)[1]			**516.5**	131.0
Gas Distribution and Services				
Debentures	11.06%	2009 - 2024	**485.0**	585.0
Medium-term notes	5.69%	2008 - 2036	**1,865.0**	1,665.0
Other			**9.4**	8.2
Corporate				
U.S.dollar term notes (US$1,354.3 million; 2006 – US$417.0 million)	5.69%	2014 - 2022	**1,341.2**	485.9
Medium-term notes	5.72%	2008 - 2035	**1,900.0**	2,094.9
Preferred securities			**–**	200.0
Other (US$317.0 million; 2006 – US$348.4 million)[2]			**1,252.2**	1,396.4
Deferred debt issue costs *(Note 2)*			**(59.7)**	–
Total Debt			**8,334.2**	7,591.0
Current Maturities			**(605.2)**	(537.0)
Long-Term Debt			**7,729.0**	7,054.0

1 *Primarily credit facility draws.*

2 *Primarily commercial paper borrowings.*

Short-term debt of $1,764.8 million (2006 – $1,519.1 million) is supported by the availability of long-term committed credit facilities and has been classified as long-term debt.

Long-term debt maturities for the years ending December 31, 2008 through 2012 are $605.2 million, $455.0 million, $600.9 million, $151.1 million and $251.1 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates.

On February 15, 2007, the Company redeemed $200.0 million of 7.8% Preferred Securities for $25.00 per security plus accrued and unpaid interest.

FAIR VALUE OF DEBT

December 31,	**2007**		2006	
(millions of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liquids Pipelines	**1,541.1**	**1,642.5**	1,155.6	1,301.6
Gas Distribution and Services	**2,359.4**	**2,571.0**	2,258.2	2,613.8
Corporate	**4,493.4**	**4,640.7**	4,177.2	4,294.0

The fair value of debt does not include the effects of hedging.

INTEREST EXPENSE

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Long-term debt	**439.5**	403.4	382.8
Non-recourse long-term debt	**102.0**	104.9	112.1
Commercial paper and other short-term debt	**54.5**	60.3	40.6
Short-term borrowings	**15.2**	19.1	12.7
Capitalized	**(61.2)**	(20.6)	(9.0)
	550.0	567.1	539.2

In 2007, total interest paid was $607.3 million (2006 – $563.3 million; 2005 – $537.1 million).

INTEREST RATE MANAGEMENT

The impact on effective interest rates of derivative instruments used to manage interest rate risk and the debt related to these instruments are as follows:

(millions of dollars) **December 31, 2007**	Maturity	Effective Interest Rate[1]	Notional Amounts
Liquids Pipelines			
Floating to fixed interest swap (commercial paper)	2029	6.0%	25.4
Corporate			
Floating to fixed interest swap (commercial paper)	2008 - 2009	4.5%	750.0
Floating to fixed interest swap (commercial paper)	2008 - 2009	4.3%	US$186.6

1 *After giving effect to the derivative financial instruments.*

CREDIT FACILITIES

(millions of dollars) **December 31, 2007**	Expiry Dates	Total Facility	Available	Drawdowns
Liquids Pipelines	2008 - 2009	794.1	433.4	360.7
Gas Distribution and Services	2008 - 2009	1,006.9	1,000.0	6.9
Corporate	2009 - 2012	3,842.9	3,842.9	–
		5,643.9	5,276.3	367.6

Credit facilities carry a weighted average standby fee of 0.062% per annum on the unused portion and drawdowns bear interest at market rates. Certain credit facilities serve as a backstop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2009 to 2012.

13. NON-RECOURSE DEBT

(millions of dollars) December 31,	Weighted Average Interest Rate	Maturity	**2007**	2006
Gas Pipelines				
Long-term credit facilities				
(US$1.9 million; 2006 – US$6.0 million)	5.26%	2012	**1.9**	6.9
Senior notes (US$441.8 million; 2006 – US$469.5 million)	6.74%	2015 - 2025	**436.5**	547.1
Capital lease obligations	11.24%	2013 - 2020	**39.9**	49.6
Sponsored Investments				
Credit facilities	5.12%	2010 - 2012	**141.5**	94.4
Medium-term notes	4.69%	2009 - 2014	**190.0**	190.0
Senior notes	6.85%	2015 - 2025	**707.7**	733.7
Fair value increment on senior notes acquired			**43.3**	48.2
Gas Distribution and Services				
Term debt (US$15.7 million; 2006 – US$5.8 million)	6.3%	2008 - 2010	**15.5**	6.8
Capital lease obligations	12.0%	2016 - 2021	**4.9**	5.4
Deferred debt issue costs *(Note 2)*			**(11.7)**	–
Total Non-Recourse Debt			**1,569.5**	1,682.1
Current Maturities			**(61.1)**	(60.1)
Non-Recourse Long-Term Debt			**1,508.4**	1,622.0

Long-term debt maturities on non-recourse borrowings for the years ending December 31, 2008 through 2012 are $61.1 million, $168.3 million, $176.8 million, $68.6 million and $118.4 million, respectively. The medium-term notes and senior notes bear interest at fixed rates.

Certain assets of Alliance Pipeline Canada are pledged as collateral to Alliance Pipeline Canada's lenders and to the lenders to Alliance Pipeline US. As well, certain assets of Alliance Pipeline US are pledged as collateral to Alliance Pipeline US's lenders and to the lenders to Alliance Pipeline Canada.

Not including the effects of hedging, non-recourse debt has a fair value of $1,634.8 million (2006 – $1,786.6 million).

14. NON-CONTROLLING INTERESTS

(millions of dollars) December 31,	**2007**	2006
EEM	**335.1**	398.5
EGD Preferred Shares	**100.0**	100.0
EIF	**155.9**	167.3
EGNB	**48.8**	39.8
Other	**10.7**	9.6
	650.5	715.2

Non-controlling interest in EEM represents the 82.8% of the listed shares of EEM not held by the Company.

The Company owns 100% of the common shares of EGD; however, the 4,000,000 4.82% Cumulative Redeemable EGD Preferred Shares held by a third party are entitled to a claim on the assets of EGD prior to the common shareholder. Subsequent to July 1, 2009, EGD may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 plus all accrued and unpaid dividends to the redemption date. The preferred shares have no fixed maturity date.

Non-controlling interest in EIF represents 58.1% of voting units which are held by public unitholders. Non-controlling interest in EGNB represents 29.2% held by third parties.

15. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preferred shares.

COMMON SHARES

December 31,

	2007		2006		2005	
(millions of dollars; number of common shares in millions)	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	**351.8**	**2,416.1**	348.9	2,343.8	346.2	2,282.4
Common shares issued	**15.0**	**566.4**	–	–	–	–
Exercise of stock options	**1.2**	**26.3**	2.4	53.9	2.1	40.0
Dividend Reinvestment and Share Purchase Plan	**0.5**	**17.7**	0.5	18.4	0.4	14.6
Issued for business acquisition	**–**	**–**	–	–	0.2	6.8
Balance at end of year	**368.5**	**3,026.5**	351.8	2,416.1	348.9	2,343.8

PREFERRED SHARES

The 5.0 million 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, quarterly preferential dividends of $1.375 per share per year. The Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25.00 per share plus all accrued and unpaid dividends.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 11.1 million shares (2006 – 10.6 million shares), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes that any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

(number of common shares in millions) December 31,	**2007**	2006	2005
Weighted average shares outstanding	**355.3**	340.0	337.4
Effect of dilutive options	**3.0**	3.3	3.8
Diluted weighted average shares outstanding	**358.3**	343.3	341.2

For the year ended December 31, 2007, 1,158,200 anti-dilutive stock options (2006 – 1,548,900; 2005 – nil) with a weighted average exercise price of $38.26 (2006 – $36.47) were excluded from the diluted earnings per share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

Under the Dividend Reinvestment and Share Purchase Plan, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges.

SHAREHOLDER RIGHTS PLAN

The Shareholder Rights Plan is 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 Company's Board of Directors. Should such an acquisition 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.

16. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four plans for mid to long-term incentive compensation: the Incentive Stock Option (ISO) Plan, Performance Based Stock Option (PBSO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. A maximum of 30 million common shares were reserved for issuance under the 2002 ISO plan, of which 14.7 million have been issued to date. In 2007, a new reserve of 16.5 million shares was approved and established for the 2007 ISO and PBSO plans. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2007 for ISOs is $9.0 million (2006 – $10.5 million; 2005 – $5.5 million).

Outstanding Incentive Stock Options

December 31,

	2007		2006		2005	
(options in thousands; exercise price in dollars)	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**9,186**	**24.97**	9,434	22.09	9,650	19.86
Options granted	**1,158**	**38.26**	1,595	36.41	1,533	31.70
Options exercised	**(1,046)**	**19.21**	(1,698)	19.38	(1,617)	17.51
Options cancelled or expired	**(61)**	**32.97**	(145)	28.81	(132)	26.39
Options at end of year	**9,237**	**27.24**	9,186	24.97	9,434	22.09
Options vested	**5,865**	**22.87**	5,323	20.54	5,248	18.74

The total intrinsic value of ISOs exercised during the year ended December 31, 2007 was $19.1 million (2006 – $27.8 million; 2005 – $21.3 million) and cash received on exercise was $20.1 million (2006 – $32.9 million; 2005 – $28.3 million). Intrinsic value represents the difference between the Company's share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2007 was $94.2 million and $85.5 million, respectively.

Incentive Stock Option Characteristics

	Options Outstanding			Options Vested	
(options in thousands; exercise price in dollars) **December 31, 2007** Exercise Price	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
10.00 - 14.99	**441**	**2.2**	**13.28**	**441**	**13.28**
15.00 - 19.99	**1,276**	**2.4**	**18.29**	**1,276**	**18.29**
20.00 - 24.99	**2,160**	**4.6**	**21.28**	**2,160**	**21.28**
25.00 - 29.99	**1,365**	**6.0**	**25.74**	**972**	**25.74**
30.00 - 34.99	**1,370**	**7.1**	**31.79**	**648**	**31.73**
35.00 - 38.26	**2,625**	**8.5**	**37.25**	**368**	**36.47**
	9,237	**5.9**	**27.24**	**5,865**	**22.87**

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes option pricing model are as follows:

Year ended December 31,	**2007**	2006	2005
Fair value per option (dollars)	**6.16**	6.30	5.31
Valuation assumptions[1]			
Expected option term (years)	**6**	8	8
Expected volatility	**18.10%**	19.00%	16.00%
Expected dividend yield	**3.22%**	3.23%	3.17%
Risk-free interest rate	**4.11%**	4.16%	4.40%

1 The expected option term and the expected volatility are based on historical information.

As of December 31, 2007, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO plan was $8.5 million. The cost is expected to be recognized over a period of 2.3 years.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 and August 15, 2007. All performance targets and time vesting requirements for the 2002 PBSO grant have been met. The 2002 PBSO grant will expire on September 16, 2010. The 2007 PBSO grant performance targets are based on the Company's share price. Time vesting requirements for the 2007 PBSO grant are fulfilled evenly over a five-year term, ending August 15, 2012. Under the 2007 PBSO plan performance vesting targets must be met by February 15, 2014 otherwise the options expire. If targets are met by February 15, 2014, the options are exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2007 for PBSOs was $0.7 million.

Outstanding Performance Based Stock Options

December 31,

(options in thousands; exercise price in dollars)	**2007** Number	**2007** Weighted Average Exercise Price	2006 Number	2006 Weighted Average Exercise Price	2005 Number	2005 Weighted Average Exercise Price
Options at beginning of year	**1,379**	**23.15**	2,105	21.57	2,555	20.68
Options granted	**2,345**	**36.57**	–	–	–	–
Options exercised	**(136)**	**23.15**	(645)	18.00	(450)	16.51
Options cancelled	**–**	**–**	(81)	23.15	–	–
Options at end of year	**3,588**	**31.92**	1,379	23.15	2,105	21.57
Options vested	**1,243**	**23.15**	1,119	23.15	1,457	20.87

The total intrinsic value of PBSOs exercised during the year ended December 31, 2007 was $1.9 million (2006 – $11.4 million; 2005 – $7.8 million) and cash received on exercise was $3.1 million (2006 – $11.6 million; 2005 – $7.4 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2007 is $19.8 million and $17.8 million, respectively.

Performance Based Stock Option Characteristics

(options in thousands; exercise price in dollars) **December 31, 2007** Exercise Price	Options Outstanding Number	Options Outstanding Weighted Average Remaining Life (years)	Options Outstanding Weighted Average Exercise Price	Options Vested Number	Options Vested Weighted Average Exercise Price
23.15	**1,243**	**2.7**	**23.15**	**1,243**	**23.15**
36.57	**2,345**	**7.6**	**36.57**	**–**	**–**
	3,588	**5.9**	**31.92**	**1,243**	**23.15**

Assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	**2007**
Fair value per option (dollars)	**3.40**
Valuation assumptions[1]	
Expected option term (years)	**8**
Expected volatility	**13.60%**
Expected dividend yield	**3.57%**
Risk-free interest rate	**4.38%**

1 *The expected option term and the expected volatility are based on historical information.*

As of December 31, 2007, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO plan was $7.3 million. The cost is expected to be recognized over a period of 4.6 years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's current share price and by a performance multiplier. The performance multiplier ranges from 0, if the Company's performance fails to meet threshold performance levels, to a maximum of 2, if the Company performs within the highest range of its performance targets. The performance multiplier for the 2005 and 2006 grants is based on the Company's total shareholder return over the three-year performance period relative to a specified peer group of

companies. The 2007 grant derives the performance multiplier through a calculation of the Company's Price/Earnings ratio relative to a specified peer group of companies and the Company's growth in earnings per share relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2007 for PSUs was $3.0 million (2006 – $4.1 million; 2005 – $2.5 million). An estimated performance multiplier of 0.73, 1.0 and 1.0 was used to calculate the expense based upon historical performance for the 2005, 2006 and 2007 grants, respectively.

Outstanding Performance Stock Units

December 31,	**2007**	2006	2005
Units at beginning of year	**328,716**	200,652	67,688
Units granted	**137,200**	117,900	130,130
Units cancelled	**(2,384)**	–	(3,265)
Units matured	**(209,827)**	–	–
Dividend reinvestment	**13,911**	10,164	6,099
Units at end of year	**267,616**	328,716	200,652

Of the PSUs outstanding at December 31, 2007, 125,777 units have a performance period ending December 31, 2008 and 141,839 units have a performance period ending December 31, 2009. The total intrinsic value of PSUs outstanding at December 31, 2007 is $10.7 million.

RESTRICTED STOCK UNITS

Enbridge has a RSU plan where cash awards are granted to certain non-executive employees of the Company. After the thirty-five month maturity period, RSU holders receive cash equal to the Company's current share price for each RSU held. Compensation expense recorded for the year ended December 31, 2007 for RSUs was $7.1 million (2006 – $0.8 million; 2005 – nil).

Outstanding Restricted Stock Units

December 31,	**2007**	2006
Units at beginning of year	**183,253**	–
Units granted	**276,875**	181,882
Units cancelled	**(18,627)**	–
Dividend reinvestment	**15,120**	1,371
Units at end of year	**456,621**	183,253

The total intrinsic value of RSUs outstanding at December 31, 2007 is $18.3 million.

As of December 31, 2007, unrecognized compensation expense related to non-vested units granted under the PSU and RSU plans was $15.5 million, expected to be recognized over a period of 1.7 years.

17. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

(millions of dollars)	Cash Flow Hedges	Equity Investees	Non-Controlling Interests	Cumulative Translation Adjustment	Net Investment Hedges	Total
Balance at January 1, 2006	–	–	–	(486.7)	428.1	(58.6)
Tax impact	–	–	–	–	(113.2)	(113.2)
	–	–	–	(486.7)	314.9	(171.8)
Changes during the period	–	–	–	87.6	(49.0)	38.6
Tax impact	–	–	–	–	(2.6)	(2.6)
	–	–	–	87.6	(51.6)	36.0
Balance at December 31, 2006	–	–	–	(399.1)	263.3	(135.8)
Adjustment on adoption *(Note 2)*	**79.4**	**(57.3)**	**26.3**	**–**	**–**	**48.4**
Tax impact	**(20.3)**	**20.1**	**–**	**–**	**–**	**(0.2)**
	59.1	**(37.2)**	**26.3**	**–**	**–**	**48.2**
Changes during the period	**94.8**	**(29.2)**	**4.9**	**(447.1)**	**193.9**	**(182.7)**
Tax impact	**(5.1)**	**9.4**	**–**	**–**	**(19.0)**	**(14.7)**
	89.7	**(19.8)**	**4.9**	**(447.1)**	**174.9**	**(197.4)**
Balance at December 31, 2007	**148.8**	**(57.0)**	**31.2**	**(846.2)**	**438.2**	**(285.0)**

18. FINANCIAL INSTRUMENTS & RISK MANAGEMENT

DERIVATIVE FINANCIAL INSTRUMENTS USED FOR RISK MANAGEMENT

Enbridge's earnings are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively, market price risk). The Company uses derivative financial instruments for market price risk management purposes. The following summarizes the types of market price risks to which the Company is exposed, and the risk management instruments to mitigate them.

Foreign Exchange

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar and euro denominated investments, where both carrying values and earnings are subject to foreign exchange rate variability. The Company uses long dated par forward contracts and cross currency swaps to manage a portion of the foreign exchange exposure related to both changes in carrying values of its equity investments and cash flows from other investments. In addition, the Company also uses short term foreign exchange forward contracts to manage exposure related to foreign currency denominated receivables and payables.

Interest Rate Risk

The Company is exposed to interest rate fluctuations on the cost of variable rate debt. Floating to fixed interest rate swaps, collars and forward rate agreements are used to hedge against the effect of future interest rate movements. The Company is also exposed to fluctuations in interest rates ahead of anticipated fixed rate debt issuances. The Company may enter into treasury locks or forward starting interest rate swaps to hedge a portion of the interest cost of these future debt issues.

Commodity Price Risk

The Company may use natural gas price swaps, futures and options to manage the value of commodity purchases and sales that arise from capacity commitments on the Alliance and Vector pipelines. The Company may also uses natural gas, power, crude oil and natural gas liquids swaps or options to fix the value of variable price exposures that arise from other commodity usage, storage, transportation and supply agreements.

The Company's regulated Liquids Pipelines segment uses a fixed price contract and related financial instrument to manage the mix of fixed and floating power costs. The Company recognizes the fair value of the fixed price contract, the fair value of the financial instrument and a regulatory liability that will be recognized over the life of the fixed price contract. At December 31, 2007, the Company recognized a liability of $3.5 million for unrealized financial instrument losses, an asset of $27.3 million related to the fixed price power contract and a regulatory liability of $23.8 million.

FAIR VALUE OF FINANCIAL INSTRUMENTS USED FOR RISK MANAGEMENT

Derivatives

The fair values of derivatives have been estimated using year-end market information. These fair values approximate the amount the Company would receive or pay to terminate the contracts. The current portion of derivatives is included in Accounts Receivable and Other and Accounts Payable and Other, while the long-term portion is included in Deferred Amounts and Other Assets and Other Long-Term Liabilities.

December 31,	**2007**			2006		
(millions of dollars unless otherwise noted)	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	**138.0**	**46.7**	**2013 - 2022**	307.3	(0.5)	2007 - 2022
Euro cross currency swaps	**447.6**	**27.4**	**2008 - 2019**	447.6	(9.9)	2007 - 2019
Forwards (cumulative exchange amounts)	**2,608.0**	**226.3**	**2008 - 2022**	1,536.7	231.3	2007 - 2022
Interest rates						
Interest rate swaps/collars	**1,117.0**	**(8.6)**	**2008 - 2029**	1,947.3	(17.2)	2007 - 2029
Energy commodities						
Energy commodity (bcf)	**452.9**	**(43.5)**	**2008 - 2010**	100.1	(12.9)	2007 - 2011
Natural gas supply (bcf)	**0.7**	**(1.1)**	**2008**	29.1	(26.6)	2007
Power (MW/H)	**57.0**	**20.6**	**2008 - 2024**	25.8	(8.3)	2007 - 2024

Derivative Instruments used as Cash Flow Hedges

(millions of dollars unless otherwise noted) **December 31, 2007**	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange			
U.S. cross currency swaps	**138.0**	**46.7**	**2013 - 2022**
Forwards (cumulative exchange amounts)	**1,761.4**	**138.1**	**2008 - 2022**
Interest rates			
Interest rate swaps/collars	**1,117.0**	**(8.6)**	**2008 - 2029**
Energy commodities			
Energy commodity (bcf)	**43.6**	**3.2**	**2008 - 2010**
Natural gas supply (bcf)	**0.5**	**(1.0)**	**2008**
Power (MW/H, net)	**2.0**	**(2.1)**	**2008 - 2017**

The Company estimates that $1.3 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months.

Derivative and Other Financial Instruments used as Net Investment Hedges

(millions of dollars unless otherwise noted) **December 31, 2007**	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange			
Euro cross currency swaps	**447.6**	**27.4**	**2008 - 2019**
Forwards (cumulative exchange amounts)	**749.9**	**187.0**	**2013 - 2020**

The Company has also designated a US$300 million medium-term note and US$317 million of commercial paper as hedges of certain US dollar investments.

Fair Value Hedges

As at December 31, 2007, the Company did not have any outstanding fair value hedges.

Other Financial Instruments

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The fair value of other financial instruments reflects the Company's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates.

Unrealized Gains and Losses on Non-Hedging Derivatives

The Company does not use derivative instruments for speculative purposes; however, if a derivative instrument is not an effective hedge for accounting purposes or is not designated as a hedging item, changes in the fair value are recorded in current period earnings. The Company had an unrealized loss of $32.3 million (after tax) for the year ended December 31, 2007 on certain non-qualifying derivative instruments related to fixed price commodity purchases and sales.

CREDIT RISK

Entering into derivative financial instruments can give rise to credit risks. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company enters into risk management transactions only with institutions that possess high investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. The Company has no significant concentration with any single counterparty. The Company has credit risk of $267.8 million (2006 – $267.3 million; 2005 – $352.4 million) related to its derivative counterparties.

Credit risk also arises from trade receivables, which is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. Credit risk in the Gas Distribution and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process.

19. INCOME TAXES

INCOME TAX RATE RECONCILIATION

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Earnings before income taxes	**916.3**	814.6	784.2
Combined statutory income tax rate	**33.9%**	34.4%	35.2%
Income taxes at statutory rate	**310.6**	280.2	276.0
Increase/(decrease) resulting from:			
Legislated tax changes	**(62.8)**	(63.0)	1.2
Future income taxes related to regulated operations	**(5.8)**	(10.5)	(15.3)
Non-taxable items, net	**(18.5)**	(21.4)	(44.1)
Lower foreign tax rates	**(6.4)**	(6.7)	(9.6)
Large Corporations Tax in excess of surtax	**–**	–	15.1
Other	**(7.9)**	13.7	(2.0)
Income Taxes	**209.2**	192.3	221.3
Effective income tax rate	**22.8%**	23.6%	28.2%

In 2007, income taxes paid amounted to $226.2 million (2006 – $182.6 million; 2005 – $150.3 million).

COMPONENTS OF FUTURE INCOME TAXES

(millions of dollars) December 31,	**2007**	2006
Future Income Tax Liabilities		
Differences in accounting and tax bases of property, plant and equipment	**608.6**	639.8
Differences in accounting and tax bases of investments	**337.0**	375.6
Other comprehensive income	**42.4**	–
Other	**101.8**	201.7
	1,089.8	1,217.1
Future Income Tax Assets		
Loss carryforwards	**222.0**	257.9
Other	**78.9**	96.8
	300.9	354.7
Total Net Future Income Tax Liability	**788.9**	862.4

Net future income tax liability of $788.9 million (2006 – $862.4 million) includes future income tax liabilities of $975.6 million (2006 – $1,062.5) net of future tax assets of $186.7 million (2006 – $200.1 million).

At December 31, 2007, the Company has recognized the benefit of unused tax loss carryforwards of $665.1 million (2006 – $760.6 million). Unused tax loss carryforwards expire as follows: 2009 – $0.4 million; 2014 – $2.6 million; 2015 – $6.3 million and 2019 and beyond – $655.8 million.

GEOGRAPHIC COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

(millions of dollars) December 31,	**2007**	2006	2005
Earnings before income taxes			
Canada	**511.1**	430.7	487.3
United States	**210.2**	237.8	150.5
Other	**195.0**	146.1	146.4
	916.3	814.6	784.2
Current income taxes			
Canada	**152.7**	204.3	106.9
United States	**11.9**	0.1	–
Other	**3.8**	8.9	6.3
	168.4	213.3	113.2
Future income taxes			
Canada	**(36.3)**	(112.0)	49.4
United States	**77.1**	91.0	58.7
	40.8	(21.0)	108.1
Current and future income taxes	**209.2**	192.3	221.3

20. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company has three basic pension plans which provide either defined benefit or defined contribution pension benefits, or both to employees of the Company. The Liquids Pipelines and Gas Distribution and Services pension plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge U.S. pension plan provides Company funded defined benefit pension benefits for U.S. based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2007.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Liquids Pipelines	December 31, 2006	December 31, 2009
Enbridge U.S.	December 31, 2006	December 31, 2007
Gas Distribution and Services	December 31, 2006	December 31, 2009

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, pension costs equal amounts required to be contributed by the Company. Pension costs in respect of these plans during the year were $3.6 million (2006 – $3.0 million; 2005 – $2.4 million).

POST-EMPLOYMENT BENEFITS OTHER THAN PENSIONS

Post-employment benefits other than pensions primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	OPEB		Pension Benefits	
(millions of dollars)	**2007**	2006	**2007**	2006
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**193.2**	191.6	**1,109.0**	1,039.3
Service cost	**4.7**	5.2	**43.8**	37.5
Interest cost	**10.1**	10.0	**57.9**	54.2
Amendments	**–**	–	**0.1**	2.9
Employee's contributions	**0.4**	0.4	**–**	–
Actuarial loss/(gain)	**(10.2)**	(7.7)	**(46.4)**	17.3
Benefits paid	**(6.7)**	(6.2)	**(42.2)**	(42.5)
Effect of exchange rate changes	**(8.1)**	(0.1)	**(21.8)**	0.3
Benefit obligation at end of year	**183.4**	193.2	**1,100.4**	1,109.0
Change in plan assets				
Fair value of plan assets at beginning of year	**50.2**	43.3	**1,227.1**	1,191.1
Actual return on plan assets	**1.7**	1.5	**104.8**	78.8
Employer's contributions	**8.1**	11.0	**44.1**	0.7
Employee's contributions	**0.4**	0.4	**–**	–
Benefits paid	**(6.7)**	(6.2)	**(42.2)**	(42.5)
Other	**–**	–	**(1.5)**	(1.1)
Effect of exchange rate changes	**(5.9)**	0.2	**(22.4)**	0.1
Fair value of plan assets at end of year	**47.8**	50.2	**1,309.9**	1,227.1
Funded Status				
Benefit obligation	**(183.4)**	(193.2)	**(1,100.4)**	(1,109.0)
Fair value of plan assets	**47.8**	50.2	**1,309.9**	1,227.1
Overfunded/(Underfunded) status at end of year	**(135.6)**	(143.0)	**209.5**	118.1
Contribution after measurement date	**1.0**	0.4	**–**	16.7
Unamortized prior service cost	**–**	–	**12.8**	15.5
Unamortized transitional obligation/(asset)	**12.1**	13.4	**(17.6)**	(19.8)
Unamortized net loss	**32.9**	46.0	**13.5**	93.1
Net amount recognized at end of year	**(89.6)**	(83.2)	**218.2**	223.6

The amounts recognized include all of the Company's plans; however, the Gas Distribution and Services plans are funded through regulated rates on a cash basis and are not recorded as net pension assets or liabilities. Excluding Gas

Distribution and Services plans, the Company's plans using the accrual method provide for a net pension asset of $64.9 million (2006 – $66.4 million) and a net OPEB liability of $18.8 million (2006 – $17.0 million). The pension asset is recorded on the balance sheet in Deferred Amounts and Other Assets while the pension liability is recorded in Other Long-Term Liabilities, with the current portion for each recorded in working capital accounts.

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	OPEB			Pension Benefits		
Year ended December 31,	**2007**	2006	2005	**2007**	2006	2005
Discount rate	**5.71%**	5.37%	5.30%	**5.65%**	5.27%	5.24%
Average rate of salary increases				**5.00%**	5.00%	4.44%

NET PENSION PLAN AND OPEB COSTS RECOGNIZED

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Benefits earned during the year	**52.1**	45.7	32.3
Interest cost on projected benefit obligations	**68.0**	64.2	63.2
Actual return on plan assets	**(106.5)**	(80.3)	(162.9)
Difference between actual and expected return on plan assets	**19.9**	(3.4)	87.3
Amortization of prior service costs	**2.0**	2.0	2.3
Amortization of transitional obligation	**(0.9)**	(0.8)	0.2
Amortization of actuarial loss	**13.9**	15.3	9.6
Amount charged to EEP	**(11.3)**	(10.5)	(10.2)
Pension and OPEB cost recognized	**37.2**	32.2	21.8

The table reflects the pension and OPEB cost for all of the Company's benefit plans on an accrual basis. Using the cash basis for Gas Distribution and Services rate regulated plans and the accrual method for all other plans, the Company's pension cost was $23.4 million (2006 – $20.1 million; 2005 – $11.6 million), and its OPEB cost was $6.9 million for 2007 (2006 – $7.0 million; 2005 – $5.9 million).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	OPEB			Pension Benefits		
Year ended December 31,	**2007**	2006	2005	**2007**	2006	2005
Discount rate	**5.37%**	5.30%	6.21%	**5.27%**	5.24%	6.26%
Average rate of salary increases				**5.00%**	4.44%	4.00%
Average rate of return on pension plan assets	**4.50%**	4.50%	4.50%	**7.31%**	7.31%	7.31%

MEDICAL COST TREND RATES

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	10%	5%	2017
Other Medical and Dental	5%	5%	2008
U.S. Plan	10%	5%	2013

A one percent increase in the assumed medical and dental care trend rate would result in an increase of $27.3 million in the accumulated post-employment benefit obligations and an increase of $2.4 million in benefit and interest costs. A one percent decrease in the assumed medical and dental care trend rate would result in a decrease of $22.0 million in the accumulated post-employment benefit obligations and a decrease of $1.9 million in benefit and interest costs.

MAJOR CATEGORIES OF PLAN ASSETS

	OPEB				Pension Benefits			
	2007			2006	**2007**			2006
(millions of dollars) Year ended December 31,	Target	Actual	Amount	Actual	Target	Actual	Amount	Actual
Equity securities	**–**	**–**	**–**	–	**60%**	**60.7%**	**794.9**	61.1%
Fixed income securities	**100%**	**85.4%**	**40.8**	86.9%	**40%**	**33.5%**	**438.6**	34.0%
Other	**–**	**14.6%**	**7.0**	13.1%	**–**	**5.8%**	**76.4**	4.9%
Total Assets	**100%**	**100%**	**47.8**	100%	**100%**	**100%**	**1,309.9**	100%

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities.

EXPECTED RATE OF RETURN ON PLAN ASSETS

	OPEB		Pension Benefits	
Year ended December 31,	**2007**	2006	**2007**	2006
Canadian Plans	**4.50%**	4.50%	**7.25%**	7.25%
U.S. Plan	**4.50%**	4.50%	**7.75%**	7.25%

The Company manages the investment risk of its pension funds by setting a long term asset mix policy for each fund after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plans; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

PLAN CONTRIBUTIONS BY THE COMPANY

	OPEB		Pension Benefits	
(millions of dollars) Year ended December 31,	**2007**	2006	**2007**	2006
Total contributions	**8.1**	11.0	**44.1**	0.7
Contributions expected to be paid in 2008	**6.9**	7.4	**25.9**	19.8

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

(millions of dollars) Year ended December 31,	2008	2009	2010	2011	2012	2013 - 2017
Expected future benefit payments	50.0	52.3	55.0	57.5	60.6	354.8

21. OTHER INVESTMENT INCOME

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Interest income	**32.7**	29.3	28.3
Gain on reduction of EEP ownership interest	**33.9**	–	24.5
Noverco preferred dividends income	**15.8**	15.6	16.8
OCENSA investment income	**24.7**	26.8	29.0
Net foreign currency gains	**26.2**	13.3	6.8
Allowance for equity funds used during construction	**15.1**	1.5	0.9
Hurricane insurance recoveries	**14.6**	6.0	–
Other	**32.1**	15.3	36.1
	195.1	107.8	142.4

22. CHANGES IN OPERATING ASSETS AND LIABILITES

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Accounts receivable and other	**(502.1)**	3.9	(441.4)
Inventory	**159.5**	134.1	(215.7)
Deferred amounts and other assets	**(134.6)**	(67.3)	(90.2)
Accounts payable and other [1]	**503.8**	43.5	394.8
Interest payable	**(5.9)**	12.5	(1.4)
	20.7	126.7	(353.9)

1 *Changes in construction payable are included in investing activities.*

23. RELATED PARTY TRANSACTIONS

EEP does not have employees and uses the services of the Company for managing and operating its businesses. Vector Pipeline contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, are:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
EEP	**267.1**	244.9	184.7
Vector Pipeline	**4.8**	4.1	4.1
	271.9	249.0	188.8

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance Pipeline and Vector Pipeline. EGD is charged market prices for these services:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Alliance Pipeline Canada	**21.3**	23.6	22.9
Alliance Pipeline US	**15.1**	14.1	17.5
Vector Pipeline	**25.0**	27.3	29.2
	61.4	65.0	69.6

CustomerWorks Limited Partnership (CustomerWorks), a joint venture, provided customer care services to EGD under an agreement having a five-year term which expired in 2007 and was not renewed. EGD was charged market prices for these services. CustomerWorks also rented an automated billing system from Enbridge Commercial Services Inc. (ECS), a subsidiary of the Company. Amounts charged by/(to) CustomerWorks are as follows:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
EGD	**26.3**	108.5	103.6
ECS	**(1.8)**	(8.1)	(8.7)
	24.5	100.4	94.9

Enbridge Gas Services (US) Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP. Amounts paid/(recovered) are as follows:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Purchases	**43.5**	29.2	48.1
Sales	**(4.1)**	(6.3)	(4.7)
	39.4	22.9	43.4

Enbridge Gas Services Inc., a subsidiary of the Company, has transportation commitments through 2015 on Alliance Pipeline Canada and Vector Pipeline. Amounts paid are as follows:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Alliance Pipeline Canada	**8.5**	8.3	9.1
Vector Pipeline	**0.6**	0.6	0.7
	9.1	8.9	9.8

Enbridge Gas Services (US) Inc., has transportation commitments through 2015 on Alliance Pipeline US and Vector Pipeline. Amounts paid are as follows:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Alliance Pipeline US	**6.6**	6.9	7.1
Vector Pipeline	**15.6**	16.5	9.5
	22.2	23.4	16.6

Tidal Energy Marketing Inc., a subsidiary of the Company, purchases and sells commodities at prevailing market prices with EEP and a subsidiary of EEP as follows:

(millions of dollars) Year ended December 31,	**2007**	2006	2005
Purchases	**4.6**	17.0	9.7
Sales	**(5.5)**	(6.7)	–
	(0.9)	10.3	9.7

RECEIVABLE FROM AFFILIATE

The receivable from affiliate of $128.5 million (2006 – $158.8 million included in Accounts Receivable and Other), included in Deferred Amounts and Other Assets, initially resulted from the sale of Enbridge Midcoast Energy to EEP. During 2007, the original loan receivable was repaid and a new loan was entered into. The loan, denominated in U.S. dollars, bears interest at 8.4% and matures in 2017. Interest income related to the note was $10.0 million, $11.8 million and $11.7 million, in 2007, 2006 and 2005, respectively. The fair value of the receivable approximates its carrying value.

The Company also provides limited consulting and other services to investees as required. Market prices are charged for these services where they are reasonably determinable or at cost when required by regulatory agreement. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices being determined on the same basis as services provided by the Company. The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

24. COMMITMENTS AND CONTINGENCIES

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against the Company were dismissed by the Ontario Court of Justice. On November 22, 2007 EGD was served with a Notice of Appeal by the Crown seeking a new trial before a different judge. The maximum possible fine upon conviction on all charges would have been approximately $5.0 million in the aggregate.

The Company has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion is also possible. The majority of the civil actions have been settled and the Company does not expect the outstanding civil actions to result in any material financial impact.

Harper Gardens Incident

In February 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A gas fitter in the home at the time of the explosion was seriously burned. Several public authorities are investigating the incident. EGD has also been named as defendant in civil actions related to the explosion, but does not expect these actions to result in any material financial impact.

Remediation of Discontinued Manufactured Gas Plant Sites

EGD may incur future costs due to claims relating to alleged coal tar contamination at or near former manufactured gas plant (MPG) sites. In October 2002, a claim was filed for $55.0 million in damages relating to a certain MPG site. EGD filed a statement of defence in June 2003 denying liability. Although the Company believes that it has a valid defence to this claim, certain risks exist. The probable overall cost cannot be determined at this time due to uncertainty about the presence and extent of damage in addition to the potential alternative remediation approaches which vary in cost. EGD expects that costs, if any, not recovered through insurance may be recovered through rates. As such, EGD does not believe the outcome will have any material financial impact.

GST Overpayment

In December 2007, EGD discovered that it had remitted excess GST to the Canada Revenue Agency (CRA). In respect of certain months within the 2003 to 2005 calendar year periods, the amount of such overpayment is approximately $40 million and is included in accounts receivable. EGD expects that it will recover the overpayment from CRA.

CAPLA CLAIM

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners have commenced a class action against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Plaintiffs filed a motion to establish a cause of action which is one of the requirements to have the motion certified as a class action under the *Class Proceedings Act (Ontario)*. The motion was dismissed by the Ontario District Court in late 2006. The Plantiff appealed the decision and the appeal was heard by the Ontario Court of Appeal on December 18, 2007. The decision of the Court of Appeal has not been released. The Company believes it has a sound defence and intends to defend the claim. Since the outcome is indeterminable, the Company has made no provision at this time for any potential liability.

ENBRIDGE ENERGY COMPANY, INC.

Enbridge Energy Company, Inc. (EEC), a subsidiary of the Company, is the general partner of EEP. EEC's former subsidiary Enbridge Midcoast Energy Inc. (Midcoast) has been assessed by the U.S. Internal Revenue Service (IRS) for US$4.5 million in taxes, interest and penalties for its 1999 through 2001 taxation years. Midcoast has paid all amounts and has filed a claim for refund of the full amount. The IRS has challenged Midcoast's tax treatment of its 1999 acquisition of several partnerships that owned a natural gas pipeline system in Kansas (these assets were sold to EEP in 2002 and subsequently sold by EEP in 2007). The IRS position, if sustained, could decrease the U.S. tax basis for the pipeline assets, which could reduce Enbridge's earnings by up to approximately US$60.0 million, although the immediate cash tax impact would be significantly less. Enbridge believes the tax treatment of the acquisition and related tax deductions claimed were appropriate. Enbridge initiated proceedings in U.S. District Court (Houston) in 2006 to litigate this matter.

OTHER TAX MATTERS

Enbridge and its subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

OTHER LITIGATION

The Company and its subsidiaries are subject to various other legal actions and proceedings which arise in the normal course of business. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

COMMITMENTS

The Company has signed contracts for the purchase of pipe and other materials totaling $947.6 million, to be used in the construction of several Liquids Pipelines projects including the Southern Lights project, the Waupisoo Pipeline, the Alberta Clipper project, the Southern Access Expansion and Extension projects, the Hardisty Terminal project as well as the Line 4 Extension project.

25. GUARANTEES

EEC, as the general partner of EEP, has agreed to indemnify EEP from and against substantially all liabilities including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

In addition, in the event of default, EEC is subject to recourse with respect to US$124.0 million of EEP's long-term debt at December 31, 2007 (2006 – US$155.0 million).

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

In the normal course of conducting business, Enbridge enters into a wide variety of agreements which provide for indemnification to third parties. Enbridge cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, Enbridge has not made any significant payments under these indemnification provisions. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. Examples where such indemnification obligations have been issued include:

Sale Agreements for Assets or Businesses

- breaches of representations, warranties or covenants;
- loss or damages to property;

- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, the Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

26. SUBSEQUENT EVENT

On February 13, 2008 Enbridge announced it is evaluating strategic alternatives for monetizing its investment in CLH. Earnings generated by the CLH investment in 2007 were $65.6 million (2006 – $54.5 million; 2005 – $61.6 million) and cash flows were $58.2 million (2006 – $56.2 million; 2005 – $36.5 million). The book value of the CLH investment at December 31, 2007 was $626.4 million which does not include unrealized foreign exchange gains and related unrealized net investment hedge gains of $32.9 million recorded in AOCI.

27. 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

(millions of dollars, except per share amounts) Year ended December 31,	**2007**	2006	2005
Earnings under Canadian GAAP	**707.1**	622.3	562.9
Stock-based compensation[1]	**–**	–	(16.6)
Earnings under U.S. GAAP	**707.1**	622.3	546.3
Other comprehensive income/(loss) under Canadian GAAP	**(197.4)**	36.0	(32.0)
Unrealized net gain/(loss) on cash flow hedges[3]	**–**	(64.2)	72.3
Underfunded pension adjustment (net of tax)[4]	**23.3**	–	–
Comprehensive income under U.S. GAAP	**533.0**	594.1	586.6
Earnings per common share under U.S. GAAP	**1.97**	1.81	1.65
Diluted earnings per common share under U.S. GAAP	**1.95**	1.79	1.63

FINANCIAL POSITION

(millions of dollars) December 31,	2007 Canada	2007 United States	2006 Canada	2006 United States
Assets				
Cash and cash equivalents[3,6]	**166.7**	**214.4**	139.7	347.0
Accounts receivable and other [1,3,4,6]	**2,388.7**	**3,118.4**	2,045.6	2,920.0
Inventory[3,6]	**709.4**	**817.3**	868.9	1,005.0
	3,264.8	**4,150.1**	3,054.2	4,272.0
Property, plant and equipment, net[3,6]	**12,597.6**	**17,999.4**	11,264.7	15,628.4
Long-term investments[3,6]	**2,076.3**	**1,253.1**	2,299.4	1,368.8
Deferred amounts and other assets [2,3,4,5,6]	**1,182.0**	**1,653.5**	924.5	1,540.5
Intangible assets[6]	**212.0**	**302.4**	241.5	348.0
Goodwill[6]	**388.0**	**725.1**	394.9	803.2
Future income taxes[6]	**186.7**	**187.3**	200.1	200.1
	19,907.4	**26,270.9**	18,379.3	24,161.0
Liabilities and Shareholders' Equity				
Short-term borrowings	**545.6**	**545.5**	807.9	807.9
Accounts payable and other [1,3,4,6]	**2,213.8**	**3,195.1**	1,723.8	2,818.6
Interest payable[6]	**89.1**	**109.8**	95.1	108.4
Current maturities and short-term debt[6]	**605.2**	**632.7**	537.0	537.0
Current portion of non-recourse debt[3,6]	**61.1**	**60.9**	60.1	83.2
	3,514.8	**4,544.0**	3,223.9	4,355.1
Long-term debt[4]	**7,729.0**	**10,600.5**	7,054.0	7,054.0
Non-recourse long-term debt[3,6]	**1,508.4**	**1,508.4**	1,622.0	4,029.6
Other long-term liabilities[3,5,6]	**253.9**	**479.2**	91.1	310.8
Future income taxes[2,3,4,5,6]	**975.6**	**1,545.7**	1,062.5	1,696.4
Non-controlling interests[6]	**650.5**	**2,355.2**	715.2	2,163.9
	14,632.2	**21,033.0**	13,768.7	19,609.8
Shareholders' Equity				
Preferred shares	**125.0**	**125.0**	125.0	125.0
Common shares	**3,026.5**	**3,026.5**	2,416.1	2,416.1
Contributed surplus	**25.7**	**–**	18.3	–
Retained earnings	**2,537.3**	**2,504.4**	2,322.7	2,242.8
Additional paid in capital	**–**	**69.6**	–	62.2
Foreign currency translation adjustment[4]	**–**	**–**	(135.8)	–
Accumulated other comprehensive loss [4,5]	**(285.0)**	**(333.3)**	–	(159.2)
Reciprocal shareholding	**(154.3)**	**(154.3)**	(135.7)	(135.7)
	5,275.2	**5,237.9**	4,610.6	4,551.2
	19,907.4	**26,270.9**	18,379.3	24,161.0

1 Stocked-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 PBSOs 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 PSUs and 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 PBSOs issued subsequent to that date.*

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. At December 31, 2007, a deferred tax liability of $572.7 million (2006 – $648.7 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 $785.6 million (2006 – $926.7 million).

3 Accounting for Joint Ventures

U.S. GAAP requires the Company's investments in joint ventures to be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for jointly controlled investments need not be reconciled from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity. 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 Accumulated Other Comprehensive Loss

The only Canadian – U.S. GAAP difference in accumulated other comprehensive loss is the underfunded status of the pension and OPEB plans. The Company estimates that approximately $1.3 million related to pension and OPEB plans at December 31, 2007 will be reclassified into earnings during the next twelve months.

Financial instruments are now recognized in Canadian GAAP in substantially the same manner as U.S. GAAP. As a result of the change in Canadian accounting, certain comparative balances have been reclassified for U.S. GAAP purposes, including the recognition of regulated non-financial instruments and offsetting regulatory liabilities as well as OCI from equity investees. In addition, transaction costs arising from the issuance of debt are now recorded net against the related long-term debt. For U.S. GAAP, these transaction costs are reclassified to deferred amounts and other assets.

5 Pension Funding Status

The Company adopted FAS 158, Employers' Accounting for Defined Pension and Other Postretirement Plans *, effective December 31, 2006. FAS 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit post retirement plan or OPEB as an asset or liability and to recognize changes in the funded status in the period in which they occur through comprehensive income. FAS 158 adjustments resulted in an increase in the net liability of $73.1 million (2006 – $110.1 million) for the underfunded status of the plans, a decrease in deferred tax liability of $24.8 million (2006 – $38.5 million) and an increase in accumulated other comprehensive loss of $48.3 million (2006 – $71.6 million). As required by FAS 158, the Company will change the measurement date of its defined benefit pension plan from September 30 to December 31, effective the year ended 2008.*

6 Consolidation of a Limited Partnership

Effective January 1, 2006, the Company adopted, without restatement of prior periods, EITF 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. *As a result of adopting EITF 04-5, the Company is consolidating its 15.1% interest in Enbridge Energy Partners for U.S. GAAP purposes, resulting in an increase to both assets and liabilities of $5,932.7 million (2006 – $5,084.8 million) and no changes to equity and earnings.*

7 Uncertain Tax Positions

On January 1, 2007, the Company adopted FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109. *FIN 48 addresses the threshold for recognizing a tax position in the financial statements. The adoption of FIN 48 did not have an impact on the consolidated financial statements.*

NEW ACCOUNTING STANDARDS

Fair Value Measurements

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements*. The Statement defines fair value, establishes a framework for measuring fair value in the context of GAAP and expands the disclosure surrounding fair value measurement. In January 2008, the FASB deferred the implementation of this standard indefinitely for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis until January 1, 2009. The requirements of this standard will be effective for the Company beginning on January 1, 2008.

Fair Value Option for Assets and Liabilities

In February 2007, the FASB issued Statement No. 159, *Fair Value Option for Financial Assets and Liabilities*. This standard provides companies with an option to measure, at specified election dates, certain financial assets and liabilities at fair value. Changes in fair value are recognized in earnings. The requirements of this standard will be effective for the Company beginning on January 1, 2008.

Management does not expect the adoption of these standards to significantly impact the financial statements.

Exhibit 99.5

MANAGEMENT'S DISCUSSION AND ANALYSIS

CONSOLIDATED RESULTS

FINANCIAL PERFORMANCE[1]

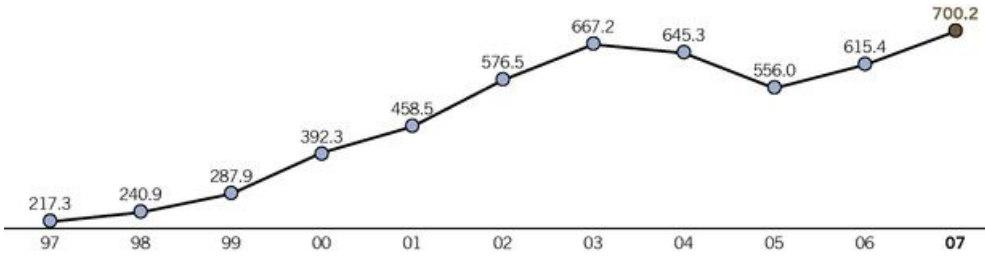
(millions of dollars, except per share amounts)	**2007**	2006	2005
Liquids Pipelines	**287.2**	274.2	229.1
Gas Pipelines	**69.7**	61.2	59.8
Sponsored Investments	**96.9**	86.8	64.8
Gas Distribution and Services	**184.1**	178.2	178.8
International	**95.1**	83.2	87.4
Corporate	**(32.8)**	(68.2)	(63.9)
Earnings Applicable to Common Shareholders	**700.2**	615.4	556.0
Earnings per Common Share	**1.97**	1.81	1.65
Diluted Earnings per Common Share	**1.95**	1.79	1.63

1 *Financial Performance data have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).*

Earnings applicable to common shareholders were $700.2 million for the year ended December 31, 2007, or $1.97 per share, compared with $615.4 million, or $1.81 per share, in 2006. The $84.8 million increase was primarily due to colder than normal weather and strong performance at Enbridge Gas Distribution (EGD), lower corporate interest expense and increased earnings at Enbridge Energy Partners, L.P. (EEP). The 2007 results also included a significant benefit from favorable legislated Canadian tax changes enacted in 2007. The positive factors were partially offset by lower contributions from the Aux Sable natural gas fractionation facility and Energy Services.

Earnings applicable to common shareholders were $615.4 million for the year ended December 31, 2006, or $1.81 per share, compared with $556.0 million, or $1.65 per share, in 2005. The $59.4 million increase in earnings was primarily the result of higher earnings from the Enbridge crude oil mainline system, strong results from EEP and from Aux Sable. The 2006 results also included $48.9 million from the revaluation of future income tax balances due to tax rate reductions enacted in 2006. These positive factors were partially offset by a lower earnings contribution from EGD as the weather in the Ontario market was significantly warmer than normal during 2006.

Earnings Applicable to Common Shareholders
(millions of Canadian dollars)



FORWARD LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this Management's Discussion and Analysis (MD&A) to provide Enbridge Inc. (Enbridge or the Company) shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of Enbridge's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. Although Enbridge believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids; prices of crude oil, natural gas and natural gas liquids; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; anticipated in-service dates and weather.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, exchange rates, interest rates and commodity prices, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to adjusted operating earnings, which represent earnings applicable to common shareholders adjusted for non-operating factors. Management believes that the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value. Management uses adjusted operating earnings to set targets and assess performance of the Company. Also, the Company's dividend payout target is based on adjusted operating earnings. Adjusted operating earnings is not a measure that has a standardized meaning prescribed by GAAP and is not considered a GAAP measure; therefore, this measure may not be comparable with a similar measure presented by other issuers.

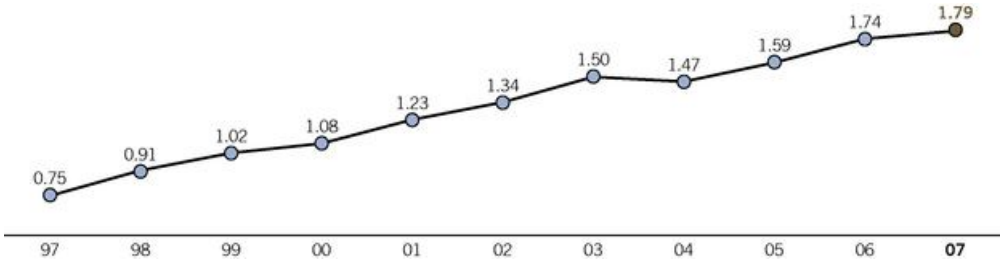
ADJUSTED OPERATING EARNINGS

(millions of dollars, except per share amounts)	**2007**	2006	2005
GAAP earnings as reported	**700.2**	615.4	556.0
Significant after-tax non-operating factors and variances:			
Liquids Pipelines			
Impact of tax changes	**(1.2)**	–	–
Gas Pipelines			
Offshore property insurance recovery from 2005 hurricanes	**(5.3)**	–	–
Sponsored Investments			
Dilution gains on EEP Class A unit issuance	**(11.8)**	–	(8.9)
EEP unrealized derivative fair value losses/(gains)	**6.3**	(6.5)	5.0
EEP gain on sale of assets of Kansas Pipeline Company	**(3.0)**	–	–
Impact of tax changes	**(1.9)**	(6.0)	–
Gas Distribution and Services			
Warmer/(colder) than normal weather affecting EGD	**(14.2)**	36.9	–
Energy Services unrealized derivative fair value losses	**2.4**	–	–
Aux Sable unrealized derivative fair value losses	**28.1**	–	–
Dilution gain in Noverco (Gaz Metro unit issuance)	**–**	(4.0)	(7.3)
Impact of tax changes	**(27.7)**	(28.9)	–
International			
Gain on land sale in CLH	**(5.2)**	–	(7.6)
Corporate			
Impact of tax changes	**(30.2)**	(14.0)	–
Adjusted Operating Earnings	**636.5**	592.9	537.2
Adjusted Operating Earnings per Common Share	**1.79**	1.74	1.59

Each of the significant non-operating factors and variances is described in the Results of Operations sections for the respective business segment.

Adjusted Operating Earnings per Common Share

(dollars per share)



Significant operating factors that increased earnings in 2007 included:

- Customer growth and higher operating margins at EGD;
- Strong operating results and an increased ownership interest in EEP; and
- Lower corporate costs due primarily to lower interest expense.

Significant operating factors that decreased earnings in 2007 included:

- Lower earnings from Aux Sable due to realized derivative losses; and
- The impact of a weaker U.S. dollar on all U.S.-based pipelines.

2007 Commercial and Construction Accomplishments:

- An Open Season commenced on the Texas Access crude oil pipeline to the Gulf Coast.
- Enbridge entered into an agreement to develop pipeline and terminal facilities for Phase 1 and subsequent phases of the Fort Hills oil sands project at a preliminary cost estimate for the initial facilities of $2 billion.
- The Neptune offshore pipelines were completed.
- The Ontario Wind Project was approved by provincial regulators and construction commenced.
- Regulatory applications were filed for the Canadian portion of the Alberta Clipper project and Line 4 Extension.
- Construction activities progressed on Southern Access Expansion, Southern Lights Pipeline, Waupisoo Pipeline and Hardisty Terminal.
- Shipper commitments and FERC approval were obtained for the Spearhead Pipeline Expansion.

CORPORATE STRATEGY

CORPORATE VISION AND KEY OBJECTIVE

Enbridge is an energy delivery company that transports natural gas and crude oil, which are used for many purposes, including to heat homes, power transportation systems and provide fuel and feedstock for industries. The Company's vision is to be North America's leading energy delivery company and its key objective is to generate superior shareholder value. The Company will deliver superior shareholder value through an investment proposition consisting of:

- above industry-average earnings per share growth;
- a strong, secure risk-reward investment profile and financial position; and
- a balanced combination of near term dividend income and superior dividend growth and capital appreciation.

STRATEGY

Enbridge's 2007 Strategic Plan consists of three broad strategies to generate superior shareholder value and position the Company for the energy environment of the future.

1. **Expand Existing Core Businesses**

   Development and operation of oil and gas energy delivery assets is our primary strength and a core competency. Enbridge's existing systems are well positioned to take advantage of evolving hydrocarbon supply and demand fundamentals and, given the challenging environment for acquisitions, most of our core business growth in the near term is expected to come from organic project development largely driven by the oil sands transportation opportunity. Strategies for each core business are included in the sections to follow.

2. Focus on Operational Excellence, People and the Environment

Enbridge will continue its focus on operational excellence, including cost efficiency, safety and reliability, effective project management, customer relationships and effective stakeholder relations. Enbridge will also focus on effective strategies for recruitment, development and retention of employees in addition to reinforcing its strong reputation for environmental stewardship and community investment.

3. Develop New Platforms for Growth and Diversification

Enbridge believes it is also important to develop new growth platforms that complement the existing core asset base to sustain longer term growth and diversify the business. Initiatives include CO_2 sequestration and transportation, liquefied natural gas (LNG) regasification, natural gas storage and new energy technologies.

To successfully pursue these strategies, the Company must mitigate certain business risks. These risks, and the Company's strategies for managing them, are described under Risk Management.

Enbridge's strategy is reviewed annually with direction from the Board of Directors. In light of its unprecedented Liquids Pipelines growth program, in 2007 the Company modified its strategy to simplify and somewhat narrow the Company's focus. The 2007 strategy de-emphasized International as a growth driver due to an extremely competitive environment that makes it difficult to find assets or new projects with acceptable risk/return profiles. Expansion is instead focused on the North American market.

The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and must meet operating, strategic and financial benchmarks before being pursued.

COMPETITIVE ADVANTAGE

The Company's ability to execute its strategy and realize its corporate vision depends primarily on three key strengths. These include the strategic position of the Company's major assets, the diversification of its businesses and its consistent focus on customer service.

The Company's assets are well positioned in North America. In the liquids business, the Company operates a major conduit between U.S. markets and the geopolitically attractive oil sands reserves in Western Canada. Enbridge has economies of scale and scheduling flexibility because of its multiple separate lines and the flexibility to move over 95 different grades of crude oil. Enbridge's existing right of way is valuable in developing major expansion projects due to increasing environmental and land-owner challenges in securing energy corridors. Also, the Company serves a diversity of markets because of the extent and reach of its pipeline systems. The gas businesses are also well located. The Ontario gas utility franchise in Toronto benefits from perennially high customer addition rates due to immigration and urbanization.

The Company's sources of earnings and growth are diversified among liquids pipelines, gas pipelines, gas distribution and international investments. As well, the Company is actively exploring new growth platforms that would further diversify and complement existing core businesses.

The Company is focused on adding value for customers and improving customers' profitability. This focus has aligned the Company with supply-demand fundamentals, which have consistently formed a basis for the Company's strategy. The Company seeks to provide value to customers in a variety of

innovative ways including provision of access to new markets for producers and new sources of supply for refiners; diversifying the supply of diluent required for transportation of heavy crude; and protection of batch quality and value.

GROWTH PROJECTS

The thrust of the Company's current strategy is growth through development and construction of new infrastructure. The Company is advancing the development of a number of organic growth projects, some of which are summarized below, which support annual organic earnings per share growth rates averaging 10% over the next four years. These projects are at various stages of development. While different milestones are relevant to each, for simplicity management has classified projects into two categories – Commercially Secured and Under Development. Commercially Secured projects, including those being undertaken by EEP, are all expected to be completed within the next four years through 2011. Projects Under Development are those which the Company believes it has a reasonable probability of competitively winning and could exceed the value of the projects already commercially secured. This "second wave" would contribute to continued acceleration of earnings growth post-2011. While Enbridge will continue to pursue acquisitions that are accretive to earnings on an opportunistic basis, growth project execution remains the Company's primary focus.

(in billions of Canadian dollars) Commercially Secured Projects[1]	Estimated Capital Cost[2]	Expenditures to Date	Expected In-Service Date	Status
Liquids Pipelines				
1. Waupisoo Pipeline	$0.6 billion	$0.4 billion	Mid-2008	Construction approximately 67% complete
2. Fort Hills Pipeline System	$2.0 billion	No significant expenditures to date	Mid-2011	Customer contract secured
3. Southern Access Mainline Expansion – Canadian portion	$0.3 billion	$0.1 billion	2006 - 2009 (in stages)	Under construction
4. Alberta Clipper – Canadian portion	$2.0 billion[3]	No significant expenditures to date	Mid-2010	Awaiting regulatory approval
5. Line 4 Extension	$0.3 billion	No significant expenditures to date	Q1 2009	Awaiting regulatory approval
6. Southern Lights Pipeline	$2.2 billion	$0.4 billion	Late 2010	Under construction (U.S.)
7. Southern Access Extension	$0.5 billion	No significant expenditures to date	Early 2009	Awaiting regulatory approval
8. Spearhead Pipeline Expansion	$0.1 billion	No significant expenditures to date	2009	Awaiting regulatory approval
9. Hardisty Terminal	$0.4 billion	$0.1 billion	2008 - 2009	Under construction
10. Stonefell Terminal	$0.1 billion	$0.1 billion	2009	Under construction
Sponsored Investments (EEP)				
11. Project Clarity – East Texas	$0.6 billion	$0.6 billion	2007 - 2008 (in stages)	Substantially complete
12. North Dakota System Expansion	$0.2 billion	No significant expenditures to date	Early 2010	Awaiting regulatory approval
13. Southern Access Mainline Expansion – U.S. portion	$2.1 billion	$1.1 billion	2008 - 2009 (in stages)	Under construction
14. Alberta Clipper – U.S. portion	$1.0 billion[3]	No significant expenditures to date	Mid-2010	Awaiting regulatory approval
Total	**$12.4 billion**			
Gas Distribution and Services				
15. Ontario Wind Project	$0.5 billion	$0.3 billion	Late 2008	Under construction

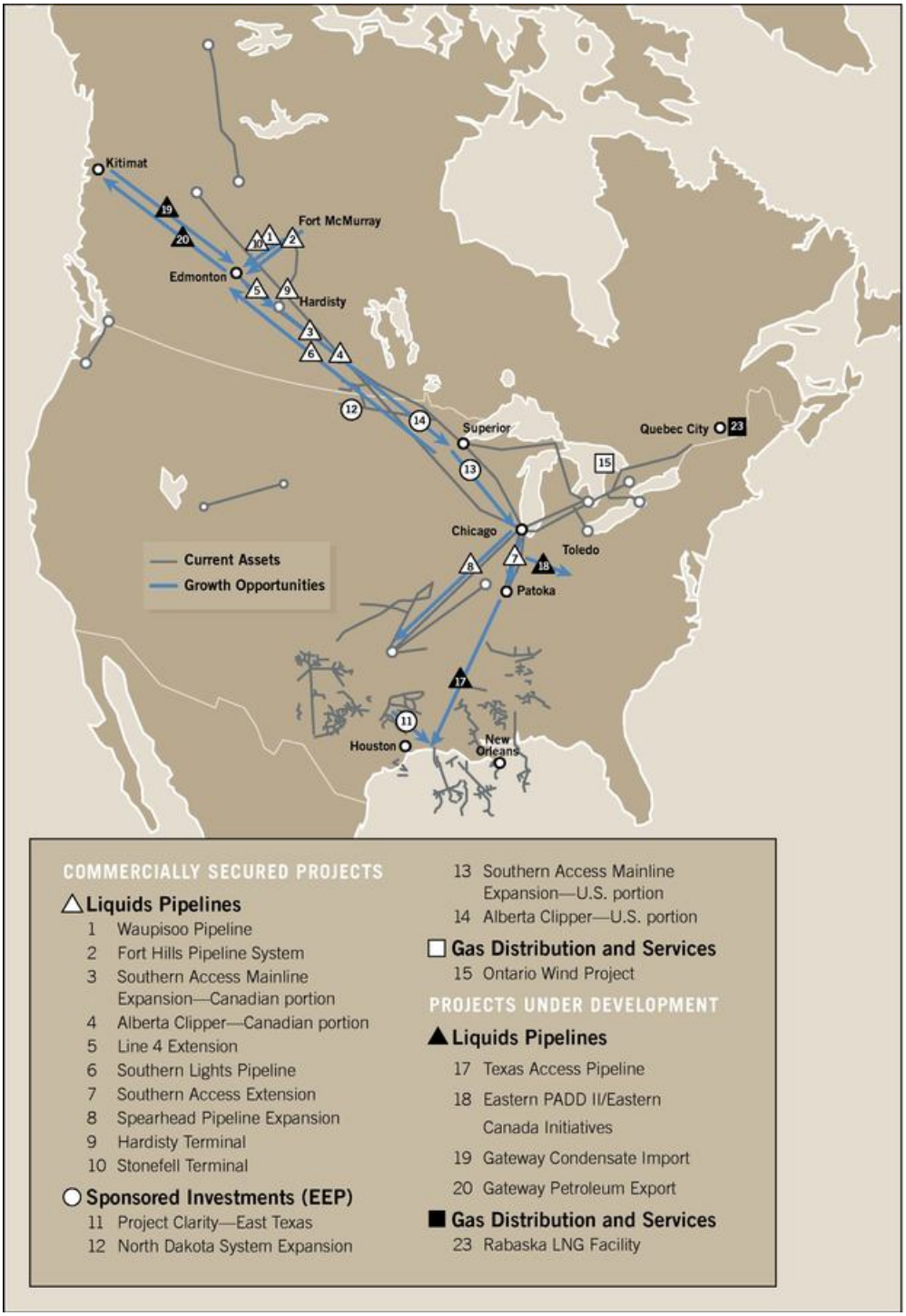
Projects Under Development[1]	*Potential In-Service Date*	*Status*
Liquids Pipelines		
16. Various Mainline Expansions	2012 - 2015	In planning stage
17. Texas Access Pipeline	2011	Obtaining shipper commitments
18. Eastern PADD II/Eastern Canada Initiatives	2010 - 2015	In commercial discussions
19. Gateway Condensate Import	2012 - 2014	In commercial discussions
20. Gateway Petroleum Export	2012 - 2014	In commercial discussions
21. Various Oil Sands Regional Facilities	2011 - 2015	In planning stage
Sponsored Investments (EEP)		
22. Various Liquids Pipelines Mainline Expansions	2010 - 2015	In planning stage
Gas Distribution and Services		
23. Rabaska LNG Facility	2011 - 2012	In commercial discussions

1 Descriptions of each project are included in the strategy section for each business segment.

2 These amounts are estimates only and subject to upward or downward adjustment based on various factors.

3 2007 dollars, excluding allowance for funds used during construction (AFUDC).

Risks related to the development and completion of organic growth projects are described under Risk Management.


Kitimat
Fort McMurray
Edmonton
Hardisty
Superior
Quebec City
Chicago
Toledo
Patoka
Houston
New Orleans
Current Assets
Growth Opportunities
COMMERCIALLY SECURED PROJECTS
Liquids Pipelines
1 Waupisoo Pipeline
2 Fort Hills Pipeline System
3 Southern Access Mainline Expansion—Canadian portion
4 Alberta Clipper—Canadian portion
5 Line 4 Extension
6 Southern Lights Pipeline
7 Southern Access Extension
8 Spearhead Pipeline Expansion
9 Hardisty Terminal
10 Stonefell Terminal
Sponsored Investments (EEP)
11 Project Clarity—East Texas
12 North Dakota System Expansion
13 Southern Access Mainline Expansion—U.S. portion
14 Alberta Clipper—U.S. portion
Gas Distribution and Services
15 Ontario Wind Project
PROJECTS UNDER DEVELOPMENT
Liquids Pipelines
17 Texas Access Pipeline
18 Eastern PADD II/Eastern Canada Initiatives
19 Gateway Condensate Import
20 Gateway Petroleum Export
Gas Distribution and Services
23 Rabaska LNG Facility

DIVIDENDS

The Company has paid common share dividends since its inception. Based on estimated 2008 dividends, the rate of increase has averaged 10% since 1953. The Company's dividend payout ratio reflects a strong and stable long-term outlook for the business. While balancing shareholders' preference for income and its own need for capital, the Company targets to pay out approximately 60% to 70% of adjusted operating earnings as dividends. In 2007, dividends paid per share were 69% of adjusted operating earnings per share (2006 – 66%, 2005 – 65%).

The chart below shows dividends per share for the last 10 years and estimated dividends for 2008, based on the quarterly dividend of $0.33 per common share declared by the Board of Directors on February 5, 2008. Average annual growth is 9%.

Effective with dividends payable on March 1, 2008, participants in the Company's Dividend Reinvestment and Share Purchase Plan will receive a 2% discount on the purchase of common shares with reinvested dividends.

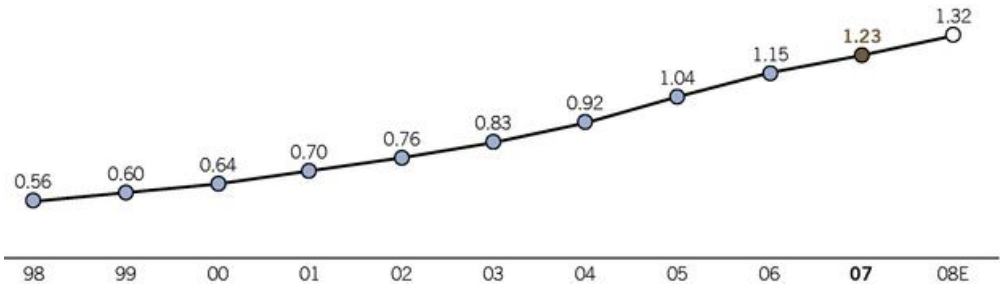
CORPORATE SOCIAL RESPONSIBILITY

At Enbridge, being socially responsible means doing things right, and doing the right thing. Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical way; protecting the environment and the health and safety of people; supporting human rights; and engaging, respecting and supporting the communities and cultures with which the Company works.

A comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees. Examples include compliance with applicable Sarbanes-Oxley requirements and the Canadian securities regulators' corporate governance guidelines and rules, the use of internal and external reviews and audits to assess each business segment's compliance with government regulations and our internal policies and management systems, and to provide guidance for making improvements. Employee and Director compliance with Enbridge's Statement on Business Conduct, a majority of independent Directors on the Company's Board of Directors as well as plain and open communication with stakeholders are other examples of stewardship and accountability.

Environmental initiatives include pursuing alternative and renewable energy technologies, minimizing pipeline leaks by conducting on-going inspection and maintenance programs and the development of a strategy to reduce greenhouse gas emissions. This strategy involves improving the energy efficiency of pipelines, encouraging the efficient use of natural gas by customers and replacing older cast iron pipe at EGD with new polyethylene mains. Enbridge engages employees on health and safety issues through training, communication programs and the establishment of local and regional environmental, health and safety committees.

Dividends per Common Share
(dollars per share)



Stakeholder relations involves developing and maintaining positive relationships with employees, contractors, suppliers, customers, landowners, investors, environmental groups, business partners, government agencies and regulators, provincial, state and federal legislators, local officials, community residents and the media. Initiatives include early-stage project consultation with a variety of stakeholders on organic growth projects and public awareness programs on pipeline safety.

Enbridge supports universal human rights and reinforces this principle with comprehensive policies and practices addressing human rights. For example, Enbridge was one of the first Canadian companies to adopt the Voluntary Principles on Security and Human Rights, which stress the importance of promoting and protecting human rights throughout the world and the constructive role business can play in advancing these goals.

The Company makes voluntary contributions to charitable and non-profit organizations in the areas of: education, health, environment, social services, arts and culture, community leadership and volunteerism, in order to contribute to the economic and social development of communities where Enbridge employees live and work.

While Enbridge is focused on generating long-term value for investors, Corporate Social Responsibility defines the Company's commitment to achieving and sustaining that objective in a socially and environmentally responsible way.

CORE BUSINESSES

The Company's activities are carried out through five business units:

- Liquids Pipelines, which includes the operation of the Enbridge crude oil mainline system and feeder pipelines that transport crude oil and other liquid hydrocarbons;
- Gas Pipelines, which consists of the Company's interests in natural gas pipelines including Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines;
- Sponsored Investments, which includes investments in Enbridge Income Fund (EIF) and EEP, both managed by Enbridge;
- Gas Distribution and Services, which consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing businesses; and
- International, which includes the Company's two energy-delivery investments outside of North America.

LIQUIDS PIPELINES

Liquids Pipelines consists of crude oil, natural gas liquids (NGLs) and refined products pipelines in Canada and the United States.

EARNINGS

(millions of dollars)	**2007**	2006	2005
Enbridge System	**202.5**	202.3	170.1
Athabasca System	**53.7**	52.8	48.6
Olympic Pipeline	**9.9**	6.5	–
Spearhead Pipeline	**10.0**	6.3	(1.1)
Southern Lights Pipeline	**6.8**	–	–
Feeder Pipelines and Other	**3.1**	6.3	11.5
Impact of tax changes	**1.2**	–	–
	287.2	274.2	229.1

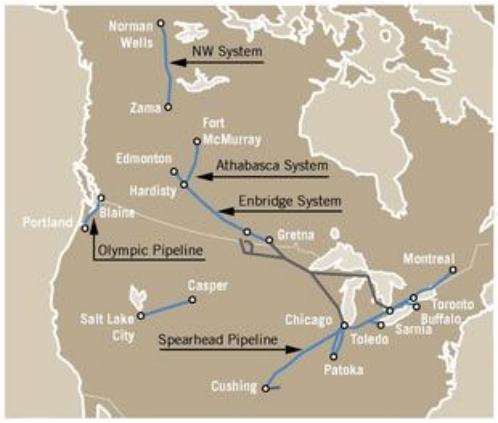
Liquids Pipelines earnings were $287.2 million in 2007 compared with $274.2 million in 2006. The increase was due primarily to strong contributions from Olympic and Spearhead Pipelines as well as the recognition of an allowance for equity funds used during construction (AEDC) on the Southern Lights Pipeline.

Liquids Pipelines earnings were $274.2 million in 2006 compared with $229.1 million in 2005. The increase resulted from strong results from the Enbridge System, the commencement of operations of the Spearhead Pipeline and the acquisition of the Olympic Pipeline.

Revenues in the Liquids Pipelines segment increased to $1,090.9 million in the year ended December 31, 2007 from $1,048.1 million in the year ended December 31, 2006. The increased revenue was partially due to increased volumes on Spearhead Pipeline and higher tolls on Olympic Pipeline. In addition, revenue reflected full year contribution from Spearhead Pipeline and Olympic Pipeline.

Revenues in the Liquids Pipelines segment increased to $1,048.1 million in the year ended December 31, 2006 from $881.0 million in the year ended December 31, 2005. The increased revenue was due to a higher revenue requirement on the Enbridge System as well as the start up of Spearhead Pipeline, which commenced operations in the first quarter of 2006 and Olympic Pipeline, which was acquired in the first quarter of 2006.

Liquids Pipelines Earnings
(millions of dollars)
The increase in Liquids Pipelines earnings in 2007 was due primarily to strong contributions from Olympic and Spearhead Pipelines as well as the recognition of an allowance for equity funds used during construction on the Southern Lights Pipeline.



Liquids Pipelines

ENBRIDGE SYSTEM

The mainline system is comprised of the Enbridge System and the Lakehead System (the portion of the mainline in the United States that is operated by Enbridge and owned by EEP). Enbridge has operated, and frequently expanded, the mainline system since 1949. Through five adjacent pipelines with a combined capacity of approximately 2.0 million barrels per day (bpd), the system transports various grades of crude oil and diluted bitumen from Western Canada to the Midwest region of the United States and Eastern Canada. Also included in the Enbridge System and located in Eastern Canada are two crude oil pipelines and one refined products pipeline with a combined capacity of 0.4 million bpd. The average utilization in 2007 was 80% and it is expected to increase in 2008.

Results of Operations

Enbridge System earnings were $202.5 million for the year ended December 31, 2007 compared with $202.3 million for the year ended December 31, 2006. The effect of increased incentive tolling settlement (ITS) metrics and higher System Expansion Program (SEP) II utilization were offset by increased operating costs and higher taxes in the Terrace component, resulting in consistent earnings in 2007 and 2006.

Enbridge System earnings were $202.3 million for the year ended December 31, 2006 compared with $170.1 million for the year ended December 31, 2005. This increase reflected a number of factors including lower oil loss costs, favourable ITS performance and, within Terrace, lower taxes, higher toll revenues and the impact of higher volumes generating surcharge revenue.

Incentive Tolling

Tolls on the Enbridge System are governed by various agreements, which are subject to the approval of the National Energy Board (NEB). The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and ratemaking agreements and other contractual arrangements with customers. Significant agreements include the ITS applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement and the SEP II Risk Sharing Agreement. Tolls on the core mainline system have been governed by incentive tolling settlements since 1995.

The ITS allows the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In addition, performance metrics were added to the current ITS to further align the Company's interests with its shippers. The Company has the opportunity to increase earnings by achieving performance targets and may incur penalties if performance falls short of specified thresholds.

Enbridge achieved total metrics bonuses of approximately $11 million for the year ended December 31, 2007 compared with approximately $10 million for the years ended December 31, 2006 and 2005.

In conjunction with the Terrace Agreement, the ITS continues the throughput protection provisions included in earlier incentive tolling arrangements, ensuring the Company is insulated from volume fluctuations beyond its control. The agreements govern both current and future shippers on the pipeline and establish tolls each year based on an agreed capacity and an allowed revenue requirement. Where actual volumes on the pipeline fall short of the agreed capacity and Enbridge is unable to fully collect its annual revenue requirement, the deficiency is rolled into the subsequent year's tolls for collection from shippers at that time and a receivable, referred to as the Transportation Revenue Variance (TRV) is recognized. This basis may affect the timing of recognition of revenues compared with that otherwise expected under GAAP for companies that are not rate-regulated.

Enbridge pays taxes each year only on the tolls collected in cash; therefore, the tax payable on the TRV lags behind the recognition of the revenue by one year. As the Terrace capacity is increasingly utilized, there will be less TRV recorded and more cash tolls collected. This will result in the Company paying taxes in future years on both the prior year's TRV and the current year's cash tolls.

ATHABASCA SYSTEM

The Athabasca System, a 540-kilometre (340-mile) synthetic and heavy oil pipeline built in 1999, links the Athabasca oil sands in the Fort McMurray, Alberta region, to a pipeline transportation hub at Hardisty, Alberta. The Athabasca System, which has a design capacity of approximately 570,000 bpd, is currently configured to transport 390,000 bpd. It also includes the MacKay River, Christina Lake, Surmont and Long Lake facilities, growing merchant tankage facilities and the Company's interest in the Hardisty Caverns Limited Partnership, which provides crude oil tankage services.

Results of Operations

Earnings for the year ended December 31, 2007 were $53.7 million compared with $52.8 million for the year ended December 31, 2006. The $0.9 million earnings increase was due to earnings from infrastructure additions, partially offset by higher operating costs including increased property taxes and minor leak remediation costs.

Earnings for the year ended December 31, 2006 were $52.8 million, an increase of $4.2 million from 2005. Infrastructure additions contributed to the increase, partially offset by higher operating expenses.

The Company has a long-term (30-year) take-or-pay contract with the major shipper on the Athabasca System, which commenced in 1999. Revenue is recorded based on the contract terms negotiated with the major shipper, rather than the cash tolls collected. The contract provides for volumes and tolls that will achieve an underpinning return on equity, based on an assumed debt/equity ratio and level of operating costs. The committed volumes and the tolls specified in the contract do not generate sufficient cash revenues in the early years to compensate Enbridge for the debt and equity returns as well as the cost of providing service; therefore, Enbridge is recording a receivable in these years. This treatment ensures that the revenue recognized each period is in accordance with the contract. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

OLYMPIC PIPELINE

In February 2006, Enbridge acquired a 65% interest in the Olympic Pipeline from BP Pipelines. Olympic is the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. The pipeline system extends approximately 300 miles

(480 kilometres) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland. BP is the operator of the pipeline.

Results of Operations

Earnings for the year ended December 31, 2007 were $9.9 million compared with $6.5 million for the year ended December 31, 2006. Higher tolls as well as a full year contribution from Olympic Pipeline resulted in this $3.4 million increase. Tolls are adjusted annually to reflect the estimated cost of service for the year and any over or under collections from prior years.

SPEARHEAD PIPELINE

The Spearhead Pipeline commenced delivery of crude oil from Chicago, Illinois to Cushing, Oklahoma in March 2006. The performance of this 125,000 bpd pipeline has continued to surpass Enbridge's expectations and with the support of shippers, the Spearhead Pipeline Expansion is underway.

Results of Operations

Earnings increased to $10.0 million for the year ended December 31, 2007 compared with $6.3 million for the year ended December 31, 2006. Spearhead Pipeline commenced operations at the beginning of March 2006; therefore, 2007 earnings reflect a full year of operations as well as increased throughput.

SOUTHERN LIGHTS PIPELINE

This pipeline is currently under construction in the United States and received regulatory approval in Canada in the first quarter of 2008. Upon completion, the 180,000 bpd 20-inch diameter Southern Lights Pipeline will transport diluent from Chicago to Edmonton, Alberta.

Results of Operations

The Company is entitled to collect an AEDC in tolls once the pipeline is in service. Earnings for 2007 reflect the AEDC related to construction funding during 2007.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta, interests in a number of liquids pipelines in the United States, liquid tankage facilities and business development costs related to Liquids Pipelines activities.

Results of Operations

Earnings in Feeder Pipelines and Other were $3.1 million for the year ended December 31, 2007 compared with $6.3 million for fiscal 2006 and $11.5 million for fiscal 2005. The decrease in earnings over the past two years is primarily due to increased business development costs related to the Company's organic growth projects.

STRATEGY

The Company seeks to go beyond the traditional regulated utility business model to create additional value for customers. In addition to incentive tolling models as discussed, the Liquids Pipelines strategy focuses proactively on understanding Western Canadian supply and downstream demand fundamentals and then proposing timely new or reconfigured infrastructure solutions to improve customer profitability.

Supply and Reserves

The Liquids Pipelines growth strategy is based on the development of the vast resource of the Western Canadian Sedimentary Basin (WCSB). Increasingly, development of the oil sands resource is driving investment opportunity. The NEB estimates that total Western Canada production will be 2.5 million bpd[1] at the end of 2007. At the end of 2006, remaining established conventional oil reserves in Western Canada were estimated to be 3.7 billion barrels[2] and remaining established reserves from oil sands were estimated at 173 billion barrels [3]. Combined conventional and oil sands reserves put Canada second only to Saudi Arabia with 13.4% of the worldwide estimated proved reserves[4]. In addition, the vast Canadian oil sands resource is geopolitically secure and in close proximity to U.S. markets.

1 *National Energy Board 2007 Estimated Production of Canadian Crude Oil and Equivalent Table 1*

2 *Canadian Association of Petroleum Producers Statistical Handbook 2007*

3 *Alberta Energy and Utilities Board Alberta's Reserves 2006 and Supply/Demand Outlook/Overview*

4 *Oil and Gas Journal's Worldwide Look at Reserves and Production, December 24, 2007*

Demand

The Company's liquids pipelines depend on the demand for crude oil and other liquid hydrocarbons produced in Western Canada. Deliveries from the pipeline system are made in the Prairie Provinces, the Province of Ontario and the Great Lakes and Midwest regions of the United States. These deliveries are principally to refineries, either directly or through the connecting pipelines of other companies. Major refining centres are located near Sarnia, Nanticoke, and Toronto, Ontario; the Minneapolis-St. Paul area of Minnesota; Superior, Wisconsin; Chicago, Illinois; the Patoka/Wood River, Illinois area; Detroit, Michigan; and Toledo, Ohio. Through Company initiatives, Canadian crude oil has started to penetrate markets in southern PADD II (the U.S. Midwest) with the Spearhead Pipeline to Cushing, Oklahoma as well as the U.S. Gulf Coast (PADD III) via a third party pipeline system.

For the past four years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S. [5] The largest market for WCSB crude oil is located in the U.S. PADD II region. Over the last two years, deliveries of WCSB crude oil into this market have increased by 50,900 bpd corresponding to the growth in WCSB crude oil supply in 2007[6,7]. In the same two year period, there have been increased deliveries into other U.S. markets including PADD V (the U.S. West coast) and PADD III, where deliveries have increased by 35,300 bpd and 55,400 bpd, respectively. Deliveries into PADD IV (the U.S. Rocky Mountains) have declined by 11,800 bpd. Western Canadian demand is served by local supply and has remained relatively flat over the last two years[6]. During 2007, greater volumes of Western Canadian crude oil were transported to Ontario[7], displacing Atlantic Basin crude oi1 [6].

5 *"Table 38: Year-To-Date Imports of Crude Oil and Petroleum Products into the United States by Country of Origin, January – October 2007", Energy Information Administration/Petroleum Supply Monthly, December 2007*

6 *"Disposition of Domestic Light and Heavy Crude Oil and Imports – 2007 & 2005", National Energy Board*

7 *"2007 & 2005 Estimated Production of Canadian Crude Oil and Equivalent", National Energy Board*

KEY COMPONENTS OF THE LIQUIDS PIPELINES STRATEGY

The Liquids Pipelines strategy is driven by the industry's need for export capacity alternatives, economic sources of diluent and U.S. refiners' need to maintain diversified sources of supply. The five key components of the Liquids Pipelines strategy are described below as well as progress made to date and future plans towards further advancing the strategy.

1. Develop Regional Oil Sands Infrastructure

Increasing oil sands production will require significant new infrastructure upstream of the mainline and the Company is developing a number of projects to support the development of the Alberta oil sands. Growth opportunities already secured include construction of the Waupisoo Pipeline and the

establishment of agreements with Fort Hills Energy, L.P. to develop pipeline and terminaling facilities for the Fort Hills oil sands project.

Waupisoo Pipeline

The 30-inch diameter, 380-kilometre (236-mile) long crude oil pipeline from the Cheecham terminal on the Athabasca Pipeline to Edmonton received approval from the Alberta Energy and Utilities Board (effective January 1, 2008 the Energy Resources Conservation Board (ERCB)) in February 2007. The initial capacity of the line will be 350,000 bpd and is expandable to a maximum of 600,000 bpd with additional pumping units. Capital costs for the project are currently expected to approximate $0.6 billion. Capital cost risks are shared between the Company and the shippers. Construction is approximately 67% complete and the pipeline is expected to be in service mid-2008.

Athabasca Pipeline Expansion Projects

In April 2007, the construction and commissioning of the Athabasca Pipeline expansion projects were completed. These projects include the addition of pumping stations at Elk Point and Cheecham as well as modifications to existing pumping stations. The Elk Point expansion is in-service and the Cheecham expansion is awaiting production from the Long Lake Oil Sands Project.

Surmont Oil Sands Project

The Surmont Oil Sands Project consists of pipeline and tank facilities at the Cheecham Terminal on the Athabasca Pipeline. Enbridge has 25-year agreements with ConocoPhillips Surmont Partnership and Total E&P Canada Ltd. to provide pipeline transportation services on the Athabasca Pipeline with the flexibility for the Surmont Shippers to transfer their production to the proposed Waupisoo Pipeline to the Edmonton area. Enbridge has completed construction of the Surmont facilities and has placed them into service.

Long Lake Oil Sands Project

The Company has 25-year lateral agreements with Nexen Inc. and OPTI Canada Inc. to provide pipeline transportation services for the Long Lake Project. Under the terms of the agreements, Enbridge will construct, own and operate the pipeline and tank facilities required by the Long Lake Project as well as pipeline laterals and tank facilities at the Cheecham terminal on the Athabasca Pipeline. The construction of the laterals and facilities at Long Lake was completed in the first half of 2007 and shipments commenced in February 2008. The Company started collecting stand-by fees in 2007.



Enbridge System Deliveries

(thousands of barrels per day)

Deliveries on the Enbridge System includes Canadian mainline deliveries in Western Canada and to the Lakehead System at the U.S. border and Line 9 in Eastern Canada.

Fort Hills Pipeline System

The Company announced that it has entered into an agreement with Fort Hills Energy, L.P. to develop pipeline and terminaling facilities to meet the requirements of Phase 1 and subsequent phases of the Fort Hills oil sands project. The preliminary plan for the Fort Hills Pipeline System includes a diluted bitumen pipeline from the mine site north of Fort McMurray to the upgrader site northeast of Edmonton with a capacity of 250,000 bpd, and a parallel 70,000 bpd diluent return pipeline. The system will also consist of terminaling facilities at the mine site and the upgrader, and ancillary pipelines between the upgrader and the Edmonton pipeline hub. The estimated cost of the initial pipeline system and related facilities is approximately $2.0 billion, subject to finalization of scope and estimate refinement, with planned in-service dates in mid-2011. Construction of the Fort Hills Project including the associated pipeline facilities is subject to final approvals by the Fort Hills' partners and various regulatory approvals and permits.

2. Expand Mainline Capacity

The Chicago refining market is expected to remain a major destination for Western Canadian crude. The Company is working with shippers and refiners to further expand this market and markets beyond, both in Canada and the United States, through the Southern Access Mainline Expansion and the Alberta Clipper Project. The Line 4 Extension Project is a third, smaller debottlenecking project that has been undertaken to expand capacity.

Southern Access Mainline Expansion Project

The Southern Access Mainline Expansion Project is currently under construction and will ultimately add a total of 400,000 bpd incremental capacity to the mainline system. The U.S. segment of the expansion from the Canada/U.S. border to Flanagan, Illinois, is being undertaken by EEP and the Canadian segment from Hardisty, Alberta to the Canada/U.S. border is being undertaken by Enbridge. Tolling principles were approved by the Federal Energy Regulatory Commission (FERC) and the NEB in 2006.

Having completed phase one of the Canadian portion of this expansion in 2006, phase two construction activities are currently underway. These involve upgrades at 18 pump stations to improve pumping effectiveness.

In the United States, the expansion will be completed in stages, finishing in 2009. Currently, construction activities are underway on the 321-mile (517-kilometre) section from Superior to Delavan, Wisconsin with over 94% of welding completed. This first stage of construction of the U.S. portion of this expansion is on schedule for completion in the second quarter of 2008 and will add capacity of approximately 190,000 bpd.

Based on construction costs experienced on the initial phase of the project, the expected cost of the project has been updated to an estimated US$2.4 billion (Enbridge – $0.3 billion, EEP – US$2.1 billion). Tolls on the Canadian mainline will be fully adjusted for the actual capital cost of the expansion, while tolls on the U.S. mainline, held by EEP, will be adjusted for approximately 88% of the actual cost.

Alberta Clipper Project

The Alberta Clipper Project involves the construction of a new 36-inch diameter pipeline from Hardisty to Superior generally within or alongside Enbridge's existing right-of way. The Alberta Clipper Project will interconnect with the existing mainline system in Superior where it will provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka, Wood River and Cushing.

In the second quarter of 2007, Enbridge filed an application with the NEB to construct the 1,607-kilometre (1,000-mile) crude oil pipeline. The application includes a commercial settlement which sets out the tolling principles and risk and return parameters agreed to with shippers. The NEB hearings into the application concluded in the fourth quarter of 2007, and Enbridge expects a decision in the first quarter of 2008. Enbridge's affiliate EEP plans to file a similar application and set of toll principles with the FERC for the United States portion of the Alberta Clipper project. Subject to regulatory approval, Enbridge anticipates bringing Alberta Clipper into service in mid-2010. 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 the EEP Lakehead System in the United States. Engineering, construction planning and procurement activities continue.

The Canadian segment of the line is expected to cost $2.0 billion (2007 dollars, excluding AFUDC) and the U.S. segment, to be undertaken by EEP, is expected to cost US$1.0 billion (2007 dollars, excluding capitalized interest). Enbridge will share in cost overruns or savings against estimates, for costs deemed to be controllable costs. Controllable costs comprise approximately 70% of the total cost estimate.

Line 4 Extension Project

In the second quarter of 2007, Enbridge filed a regulatory application with the NEB for the construction and operation of the $0.3 billion Line 4 Extension project. NEB hearings into the application were completed in January 2008 and a decision is expected in the second quarter of 2008. Subject to regulatory approvals, the project, involving construction of 136 kilometres (85 miles) of 36-inch diameter pipe to connect three existing 48-inch loops on the mainline system between Edmonton and Hardisty, would begin construction in 2008 and is expected to be in service in early 2009. Procurement of long lead items and detailed engineering for the pipeline and stations is proceeding.

3. Enhance Diluent Supply

Increasing heavy oil production in Alberta requires new supplies of diluent, which is needed to dilute heavy oils for transport through pipelines. The Company is developing projects to bring diluent to Alberta from the U.S. Midwest as well as imported diluent supplies from the west coast of British Columbia, as described in the Gateway Project.

Southern Lights Pipeline

When completed, the 180,000 bpd, 20-inch diameter Southern Lights pipeline will transport diluent from Chicago to Edmonton. During the first quarter of 2007, Enbridge filed for regulatory approval of the Canadian portion of the Southern Lights pipeline with the NEB, having obtained long-term commitments from shippers in 2006. In the fourth quarter of 2007, the Company completed the NEB oral hearing for the Canadian portion of the pipeline project. Enbridge received NEB approval in the first quarter of 2008. In the United States, various federal and state regulatory processes and related hearings are continuing. In concert with the Southern Access project, construction activities are nearly complete on the 321-mile (517-kilometre) section from Superior to Delavan, Wisconsin with over 95% of welding completed. The diluent line is expected to be in service in late 2010.

The Southern Lights Pipeline project involves reversing the flow of a portion of Enbridge's Line 13, an existing crude oil pipeline which runs from Edmonton to Clearbrook, Minnesota. In order to replace the light crude capacity that would be lost through the reversal of Line 13, the Southern Lights Project also includes the construction of a new 20-inch diameter crude oil pipeline from Cromer, Manitoba to Clearbrook, and modifications to existing Line 2. These changes to the existing crude oil system will ultimately increase southbound light crude system capacity by approximately 45,000 bpd.

Based on construction costs experienced on the initial phase of the project, the expected capital cost has been updated to an estimated US$2.2 billion (including AFUDC). Based on this level of costs, the project will earn a minimum return on equity of 10% plus a premium return which depends on the extent to which throughput on the line exceeds 90% of capacity.

4. Develop New Market Access

The Company is developing new options for expanding market access for Canadian crude oil. Specific initiatives include: extending the mainline south of Chicago to Patoka, Illinois; expansion of the Spearhead Pipeline from Chicago to Cushing; developing access to the U.S. Gulf Coast through a combination of existing infrastructure and new pipelines; and developing access to markets in Asia and California with the Gateway Project.

Southern Access Extension Project

The Southern Access Extension involves the construction of a new 36-inch diameter, 400,000 bpd pipeline extending the mainline from Flanagan to Patoka, Illinois at a cost of approximately US$0.5 billion to Enbridge.

A FERC Offer of Settlement, filed in September 2006, proposing a rolled in toll design, was not approved by the FERC. The revised tolling methodology application for the Southern Access Extension Project was filed with the FERC in October 2007 and a decision is expected in the first quarter of 2008. Subject to regulatory approval, tolls will be fully adjusted for the actual capital cost of the project and construction would begin in 2008 with an estimated in-service date of 2009.

Spearhead Pipeline Expansion

This expansion, to be effected through additional pumping stations, will increase capacity from Chicago, Illinois to Cushing, Oklahoma by 65,000 bpd to 190,000 bpd. The expansion is expected to cost US$0.1 billion and to be completed in early 2009.

The Company successfully completed the Spearhead Pipeline Expansion Open Season in the second quarter of 2007 and received FERC approval of its toll filing in December 2007. Of the 65,000 bpd increased capacity, 30,000 bpd was committed to new shippers. The remaining 35,000 bpd capacity is available for spot shippers unless the committed shippers exercise their preferential right to a portion of this capacity. Preliminary engineering design has been completed for this project and construction is scheduled to commence in early 2008.

Texas Access Pipeline

In December 2007, Enbridge and ExxonMobil Pipeline Company announced the two companies will conduct a Solicitation for Binding Shipper Commitment (Open Season) for the proposed Texas Access Pipeline. The proposed Texas Access Pipeline will transport crude oil sourced from the Canadian oil sands region in Alberta and from the upper U.S Midwest to the Texas Gulf Coast. The proposed project includes a new 768-mile (1,236-kilometre), 30-inch diameter pipeline with a capacity of approximately 450,000 bpd, which will extend from Patoka, Illinois southward to Nederland, Texas. Also proposed is an 88-mile (142-kilometre), 24-inch pipeline with a capacity of approximately 180,000 bpd to transport crude oil onward from Nederland to the Houston, Texas area. The Open Season is to determine shipper interest in executing binding commitments to transport specified volumes of crude oil on the new pipeline, which is expected to be completed in 2011. The results of the Open Season will guide and determine the further development of the proposed joint venture pipeline project.

Eastern PADD II / Eastern Canada

Enbridge is exploring options to provide incremental pipeline capacity to this market. Development of this project is ongoing and would be completed in stages, with up to approximately 100,000 bpd of incremental volume added by 2010. Additional access initiative discussions have commenced with area refiners to provide incremental infrastructure in the Eastern PADD II area for service in the 2013 timeframe.

Gateway Project

The Gateway Project 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 area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat. The condensate line is expected to have a 20-inch diameter and an initial capacity of 193,000 bpd. The petroleum export line would have a 36-inch diameter and an initial capacity of 525,000 bpd. Capital cost estimates will be completed once commercial terms are finalized. Enbridge has secured third party funding support to advance the regulatory process. Subject to continued commercial support, regulatory and other approvals, the Company estimates that the Gateway in-service date will be in the 2012 to 2014 timeframe.

5. Develop Terminaling and Tankage Infrastructure

Based on producer interest, the Company is increasing its investment in contract terminals. Upstream contract tankage projects include the Hardisty Terminal, the Stonefell Terminal near Fort Saskatchewan and expansion of the Athabasca Terminal. Downstream projects are under development or consideration by Enbridge or EEP at Flanagan, Patoka, Cushing and the U.S. Gulf Coast. The Company and EEP are also constructing significant additions to the capacity of the common carrier mainline terminals at Edmonton, Superior and Chicago.

Hardisty Terminal

Enbridge is building a $0.4 billion crude oil terminal at Hardisty with a tankage capacity of 7.5 million barrels. Enbridge has executed contracts for 100% of the capacity and it is expected that the terminal will be completed in phases from late 2008 through 2009. Civil construction of the 19 tank pads was completed at the end of September 2007 and tankage construction is underway, with 30% complete at year-end. Once complete, the Hardisty Terminal will be one of the largest crude oil terminals in North America.

Stonefell Terminal

BA Energy Inc. is building a bitumen upgrader near Fort Saskatchewan, Alberta for which Enbridge has agreed to provide pipeline and terminaling services. Based on initial scope and cost estimates, Enbridge expects to invest approximately $0.1 billion in new facilities to provide tankage services at a new satellite terminal to be developed adjacent to the upgrader. Enbridge will also provide pipeline transportation for the upgrader's output from the new terminal to a refinery hub near Edmonton.

Construction is approximately 50% complete on the six tanks and ancillary facilities that comprise the Enbridge terminal facilities being constructed for BA Energy. BA Energy has recently delayed the in-service date of their upgrader until the second quarter of 2009. As a result, construction has been slowed until the in-service date of the upgrader is clear and to further secure coverage of Enbridge's costs.

The Stonefell Terminal is strategically located adjacent to several other proposed or operating upgrading facilities and pipeline systems and will be a focus for further development of contract terminaling infrastructure.

CAPITAL EXPENDITURES

In 2007, the Liquids Pipelines segment spent $151 million on capital maintenance and improvements compared with an expected $150 million. In 2008, the Company expects to spend $150 million on capital maintenance and improvements.

Total expenditures for organic growth projects described above were $1.3 billion for 2007, in line with expectations. For 2008, the Company expects to spend $2.8 billion for the organic growth projects. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

LEGAL PROCEEDING

CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners have commenced a class action against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Company believes it has a sound defence and intends to vigorously defend the claim. The Plaintiffs filed a motion to establish a cause of action, which is one of the requirements to have the motion certified as a class action under the *Class Proceedings Act* (Ontario). The motion was dismissed by the Ontario District Court in late 2006. The Plaintiff appealed the decision and the appeal was heard by the Ontario Court of Appeal on December 18, 2007. The decision of the Court of Appeal has not been released. Since the outcome is indeterminable, the Company has made no provision at this time for any potential liability.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under Risk Management.

Supply and Demand

The operation of the Company's liquids pipelines depend on the supply of, and demand for, crude oil and other liquid hydrocarbons from Western Canada. Supply, in turn, depends on a number of variables, including the availability and cost of capital and labour for oil sands projects, the price of natural gas used for steam production and the price of crude oil. Demand depends, among other things, on weather, gasoline price and consumption, manufacturing, alternative energy sources and global supply disruptions.

Alberta Royalty Review

On October 25, 2007, the Alberta government issued "The New Royalty Framework" report summarizing upcoming changes to the Alberta Royalty Program. The new Framework is effective January 2009 and involves increasing royalty rates and rate caps for conventional oil, natural gas and oil sands to adjust to fluctuating oil prices. This Framework could create economic hurdles for future oil sands development, which may affect the pace of future growth in volumes expected to flow through Enbridge's Liquids Pipelines Systems. As outlined in Enbridge's submission to the Royalty Review Panel, Enbridge shares its customers' need to ensure that Alberta remains a competitive business environment with a stable, positive and predictable investment climate. Enbridge is reviewing the government's proposed changes to the royalty regime and will be working closely with customers to better understand the implications of those changes.

ITS Metrics

The ITS governing the Enbridge System measures the Company's performance in areas key to customer service. If the Company fails to meet the baseline targets set out in the ITS for all service and reliability metrics, the Company could be required to pay penalties to shippers up to a maximum of $30 million in each of 2008 and 2009.

Potential Pressure Restrictions

The Company's liquids pipelines systems consist of individual pipelines of varying ages. With appropriate inspection and maintenance, the physical life of the pipeline is indefinitely long; however, as the pipelines age the level of expenditures required for inspection and maintenance may increase. Temporary pressure restrictions have been established on some sections of some pipelines pending completion of specific inspection and repair programs. Pressure restrictions may from time to time be established on other of the Company's pipelines. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughout if and when the full capacity of that line segment would otherwise have been utilized. Pressure restrictions to date have not given rise to any loss of throughput. While the Enbridge System is volume-protected, EEP's Lakehead System would be adversely affected by pressure restrictions that reduce volumes transported. Additionally, on the Enbridge System ITS metrics penalties may apply if available capacity is reduced below baseline targets.

Regulation

The Enbridge System and other liquids pipelines are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings from these operations. The NEB prescribes a benchmark multi-pipeline rate of return on common equity, which is 8.71% in 2008 (2007 – 8.46%). To the extent the NEB rate of return fluctuates, a portion of the Enbridge System and other liquids pipelines earnings will change. The Company believes that regulatory risk is reduced through the negotiation of long-term agreements with shippers, such as the ITS and Terrace Agreement, which govern the majority of the segment's assets.

Competition

Competition among common carrier pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets. Other common carriers are available to producers to ship Western Canadian liquids hydrocarbons to markets in either Canada or the United States. Competition could also arise from pipeline proposals that may provide access to market areas currently served by the Company's liquids pipelines. One such proposal is the Keystone Project sponsored by TransCanada Corporation to ship Western Canadian crude oil into PADD II starting in 2009. The Company believes that its liquids pipelines are serving larger markets and provide attractive options to producers in the WCSB due to their competitive tolls and multiple delivery and storage points. Also, shippers are not required to enter into long-term shipping commitments on Enbridge's mainline system. The Company's existing right-of-way provides a competitive advantage as it can be difficult and costly to obtain new rights of way for new pipelines. The ITS and the Terrace Agreement on the Enbridge System provide throughput protection which insulates the Company from negative volume fluctuations beyond its control. The Lakehead System, owned by EEP, has no similar throughput protection on its existing system but will on the Southern Access and Alberta Clipper expansions.

Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines.

GAS PIPELINES

Gas Pipelines activities consist of investments in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines. Enbridge has joint control over these investments with one or more other owners. Enbridge owns a 50% interest in the U.S. portion of the Alliance System, a 60% interest in Vector Pipeline and interests ranging from 22% to 100% in the pipelines comprising Enbridge Offshore Pipelines (Offshore).

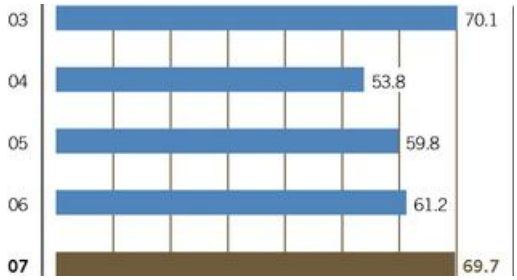
Earnings

(millions of dollars)	**2007**	2006	2005
Alliance Pipeline US	**27.7**	29.7	32.1
Vector Pipeline	**14.9**	13.4	15.9
Enbridge Offshore Pipelines	**27.1**	18.1	11.8
	69.7	61.2	59.8

Earnings from Gas Pipelines were $69.7 million for the year ended December 31, 2007 compared with $61.2 million for the year ended December 31, 2006. Earnings improved as construction of the Neptune Pipelines was completed and stand-by fees were earned starting in the fourth quarter. Also, Offshore received insurance proceeds in the second quarter of 2007 related to the 2005 hurricanes.

Earnings from Gas Pipelines were $61.2 million for the year ended December 31, 2006 compared with $59.8 million for the year ended December 31, 2005. The increase was due to improved results at Enbridge Offshore Pipelines in 2006, following two severe hurricanes in 2005. The increase was partially offset by the effects of the weaker U.S. dollar.

Revenues for the year ended December 31, 2007 were $321.3 million compared with $345.9 million for the year ended December 31, 2006. The decrease in revenues was substantially due to the effect of the stronger Canadian dollar. Revenues for the year ended December 31, 2006 were $345.9 million, consistent with $364.3 million for the year ended December 31, 2005.



Gas Pipelines Earnings

(millions of dollars)

Gas Pipelines earnings improved in 2007 as construction of the Neptune Pipelines was completed and stand-by fees were earned starting in the fourth quarter. Also, Offshore received insurance proceeds in the second quarter of 2007 related to the 2005 hurricanes.



Gas Pipelines

ALLIANCE PIPELINE US

The Alliance System (Alliance), which includes both the Canadian and U.S. portions of the pipeline system, consists of an approximately 3,000-kilometre (1,875-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 730-kilometre (455-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from northeast British Columbia and northwest Alberta to Channahon, Illinois. The pipeline has firm service shipping contract capacity to deliver 1.325 billion cubic feet per day (bcf/d). EIF, described under Sponsored Investments, owns 50% of the Canadian portion of the Alliance System.

Alliance connects with Aux Sable, a natural gas liquids extraction facility in Channahon, Illinois. The natural gas may then be transported to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to natural gas markets in the Midwestern and Northeastern United States and Eastern Canada. Enbridge owns 42.7% of Aux Sable and its results are included under Gas Distribution and Services.

Results of Operations

Alliance Pipeline earnings were $27.7 million for the year ended December 31, 2007 compared with $29.7 million for the year ended December 31, 2006. The decrease was primarily due to the stronger Canadian dollar and the depreciating ratebase. The $2.4 million decrease in earnings between the year ended December 31, 2005 and 2006 was also primarily due to the stronger Canadian dollar.

Transportation Contracts

Alliance has long-term take-or-pay contracts through 2015 to transport 1.305 bcf/d of natural gas or 98.5% of the total contracted capacity. Alliance has an additional 20 million cubic feet per day (mmcf/d) of natural gas contracted through 2010. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed return on equity. Each long-term contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. Alliance Pipeline US operations are regulated by the FERC.

Depreciation expense included in the cost of service is based on negotiated depreciation rates contained in the transportation contracts, while depreciation expense in the financial statements is recorded on a straight-line basis at 4% per annum. Negotiated depreciation expense is generally less than the financial statement amount at the beginning of the contract and higher than straight-line depreciation in the later years of the shipper transportation agreements. This difference results in recognition of a long-term receivable, referred to as deferred transportation revenue, that is expected to be recovered from shippers in subsequent years. As at December 31, 2007, $143.7 million (2006 – $159.8 million) was recorded as deferred transportation revenue.

VECTOR PIPELINE

The Company provides operating services to, and holds a 60% joint venture interest in, Vector Pipeline, which transports natural gas from Chicago to Dawn, Ontario. Vector Pipeline has the capacity to deliver a nominal 1.2 bcf/d and is operating at or near capacity.

Vector Pipeline's primary sources of supply are through interconnections with the Alliance System and the Northern Border Pipeline in Joliet, Illinois. Approximately 58% of the long haul capacity of Vector Pipeline is committed to long-term, 15-year firm transportation contracts at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates and at various term lengths. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service.

Results of Operations

Vector Pipeline earnings were $14.9 million for the year ended December 31, 2007 compared with $13.4 million for the year ended December 31, 2006. Vector Pipelines earnings improved, despite the stronger Canadian dollar, due to its late year expansion and lower operating costs in 2007.

Vector Pipeline earnings of $13.4 million for the year ended December 31, 2006 were $2.5 million lower than earnings of $15.9 million for the year ended December 31, 2005. The decrease reflected the stronger Canadian dollar and higher operating costs in 2006 due to scheduled integrity inspections required by the regulator within the first six years of operation.

STRATEGY

The Gas Pipelines strategy is developed based on the Company's forecast supply and demand for natural gas.

Supply and Demand for Natural Gas

Robust supply transported to the Chicago market is anticipated as a result of increasing conventional production in the Rocky Mountains, unconventional mid-continent production and new production from Gulf Coast LNG facilities. Surplus gas in Chicago will result in greater deliveries to the Ontario market as traditional exports from Western Canada are expected to decline. The development of oil sands projects in Alberta increases the demand for natural gas, as various extraction and upgrading processes require the use of natural gas; however, growth in this sector may be tempered by alternative energy sources. Over time, the entry of new supply from North Texas, the U.S. Rockies and the Alaska North Slope / Mackenzie Delta as well as LNG are expected to adequately supply the market and provide opportunities for Enbridge to deliver this natural gas to markets.

Alliance Pipeline Recontracting

Transportation agreements on Alliance Pipeline US expire in 2015. Alliance Pipeline US is developing strategies to maximize its competitiveness, post-2015, in light of falling export production from Western Canada and the potential for surplus export pipeline capacity. In the longer term, Alliance is well placed to benefit from incremental volumes from Northern gas.

Vector Pipeline Expansion

The US$0.1 billion construction of two additional compressor stations was completed and put in service in the fourth quarter of 2007. These stations expand the pipeline's capacity from 1 bcf/d to 1.2 bcf/d. Vector secured 10-year firm transportation contracts for the new capacity.

BUSINESS RISKS

The risks identified below are specific to Alliance Pipeline US and Vector Pipeline. General risks that affect the entire Company are described under Risk Management.

Supply and Demand

Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess capacity environment mainly because of long-term capacity contracts extending to 2015. Vector Pipeline's interruptible capacity could be negatively impacted by the basis (location) differential in the price of natural gas between Chicago and Dawn, Ontario relative to the transportation toll.

Exposure to Shippers

The failure of shippers to perform their contractual obligations could have an adverse effect on the cash flows and financial condition of Alliance Pipeline US and Vector Pipeline. To reduce this risk, Alliance Pipeline US and Vector Pipeline monitor the creditworthiness of each shipper and receive collateral for future shipping tolls should a shipper's credit position not meet tariff requirements. These pipelines also have diverse groups of long-term transportation shippers, which include various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

Competition

Alliance Pipeline US faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Competing pipelines provide natural gas transportation services from the WCSB to distribution systems in the Midwestern United States. In addition, there are several proposals to upgrade existing pipelines serving these markets. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by the Alliance System. Shippers on Alliance Pipeline US have access to additional high compression delivery capacity at no additional cost, other than fuel requirements, serving to enhance Alliance Pipeline US' competitive position.

Vector Pipeline faces competition for pipeline transportation services to its delivery points from new or upgraded pipelines, which could offer transportation that is more desirable to shippers because of cost, supply location, facilities or other factors. Vector Pipeline has mitigated this risk by entering into long-term firm transportation contracts for approximately 58% of its capacity and medium-term contracts for the remaining capacity. These long-term firm contracts provide for additional compensation to Vector Pipeline if shippers do not extend their contracts beyond the initial term. The effectiveness of these mitigating factors is evidenced by the increased utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both Vector Pipeline and Alliance Pipeline US operations are regulated by the FERC. On a yearly basis, following consultation with shippers, Alliance Pipeline US files its annual rates with the FERC for approval.

Alberta Royalty Review

The Alberta Royalty Review as described under Liquids Pipelines is also applicable to both Vector Pipeline and Alliance Pipeline US.

ENBRIDGE OFFSHORE PIPELINES

Enbridge Offshore Pipelines is comprised of 11 natural gas gathering and FERC-regulated transmission pipelines in five major corridors in the Gulf of Mexico, extending to deepwater frontiers. These pipelines include almost 1,500 miles (2,400 kilometres) of underwater pipe and onshore facilities and transported approximately 2.1 bcf/d during 2007.

Results of Operations

Offshore earnings for the year ended December 31, 2007 were $27.1 million compared with $18.1 million for the year ended December 31, 2006. In 2007, earnings included $11.3 million of insurance proceeds for both property insurance recoveries and business interruption resulting from the 2005 hurricanes. The final insurance claim settlement is expected in the first half of 2008. Offshore earnings also reflected the impact of a stronger Canadian dollar, continuing repair and inspection costs and expected continuing natural production declines on deliveries to the pipelines in 2007. Start up issues experienced by producers on key production platforms, resulting from the effects of the extreme 2005 hurricane season, delayed new sources of volumes during the year; however, volumes from the Atlantis platform started contributing to earnings at the end of 2007.

Earnings for the year ended December 31, 2006 in Enbridge Offshore Pipelines were $18.1 million compared with $11.8 million for the year ended December 31, 2005. In 2006, volumes increased, resulting in increased earnings compared with 2005 which reflected the impact of two severe hurricanes. The 2006 results were negatively impacted by the stronger Canadian dollar.

Transportation Contracts

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The throughput volume generally reflects the lease's maximum sustainable production.

The transportation contracts allow the shippers to define a maximum daily quantity (MDQ), which corresponds with the expected production life. The contracts typically have minimum throughput volumes which are subject to take-or-pay criteria but also provide the shippers with flexibility given advance notice criteria to modify the projected MDQ schedule to match current deliverability expectations.

The long-term transport rates established in the gathering and transmission service agreements are generally market-based but are established using a cost of service methodology, which includes operating cost, projected revenue generation directly tied to production deliverability and the appropriate cost of capital.

STRATEGY

Offshore intends to grow through leveraging its existing asset position to attract new prospects including producer tie-backs as well as those requiring new laterals to be constructed by Offshore. A number of new discoveries exist in deepwater and the ultra-deep areas of the Gulf of Mexico in the corridors where Offshore has existing pipeline facilities. Offshore is continually monitoring and pursuing these prospects. Projects under construction are described below.

Neptune Pipelines Project

The Neptune natural gas lateral and crude oil lateral will connect the deepwater Neptune oil and gas field in the Green Canyon Corridor to existing Gulf of Mexico pipelines, extending Enbridge's existing Gulf

of Mexico infrastructure. Except for the final subsea connections, construction of the US$0.1 billion 26-mile (42-kilometre), 20-inch diameter oil pipeline with capacity of 60,000 bpd and 26-mile (42-kilometre), 12-inch diameter gas pipeline, with capacity of 0.2 bcf/d, was completed in the fourth quarter of 2007. The Company started collecting standby fees in fourth quarter 2007 and production volumes are expected to commence in early 2008.

Shenzi Project

Enbridge has substantially completed constructing a natural gas lateral to connect the new deepwater Shenzi field to existing Gulf of Mexico pipelines. The US$45.0 million 11-mile (18-kilometre), 12-inch diameter gas pipeline has capacity of 0.1 bcf/d. In-service continues to be scheduled for mid-2009, concurrent with producer first volumes. 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.

Atlantis and Thunder Horse Production Projects

Both of these significant third party-owned projects, which will deliver natural gas into Offshore's gathering systems, have experienced startup delays due to the severe 2005 hurricanes. Atlantis, a significant source of new volumes, was placed into service in December 2007 and volumes will continue to ramp up into early 2008. The operator of the Thunder Horse project expects it to be in service in the fourth quarter of 2008.

BUSINESS RISKS

The risks identified below are specific to Enbridge Offshore Pipelines. General risks that affect the Company as a whole are described under Risk Management.

Weather

Adverse weather, such as hurricanes, may impact Offshore financial performance directly or indirectly. Direct impacts may include damage to Offshore facilities resulting in lower throughput and inspection and repair costs. Indirect impacts include damage to third party production platforms, onshore processing plants and refineries that may decrease throughput on Offshore systems.

The Company continues to maintain an active risk management program that includes comprehensive insurance coverage. However costs have increased in the form of higher insurance premiums and deductibles as well as longer waiting periods for business interruption claims. It is expected the incidence and severity of windstorm occurrences, and the Company's direct experience in the Gulf of Mexico, will dictate future costs and coverage levels in this region.

Competition

There is significant competition for new and existing business in the Gulf of Mexico. Offshore has been able to capture key opportunities and extend its footprint, positioning it to more fully utilize existing capacity. Offshore serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has Offshore well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining production, as demonstrated with the newly constructed Neptune crude oil lateral. Given rates of decline, Offshore Pipelines typically have available capacity resulting in significant and aggressive competition for new developments in the Gulf of Mexico.

Regulation

The transportation rates on many of Offshore's transmission pipelines are generally based on a regulated cost of service methodology and are subject to regulation by the FERC. These rates may be subject to challenge.

Other Risks

Other risks directly impacting financial performance include underperformance relative to expected reservoir production rates, delays in project start-up timing and capital expenditures in excess of those estimated. Capital risk is mitigated in some circumstances by having area producers as joint venture partners and through cost of service tolling arrangements. Start-up delays are mitigated by the right to collect stand-by fees.

CAPITAL EXPENDITURES

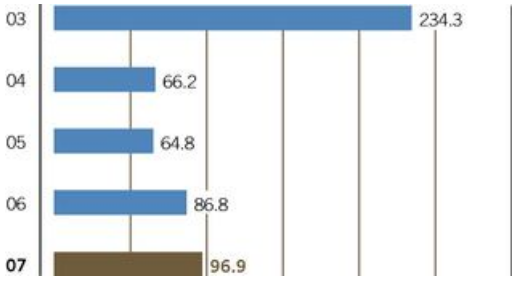
The Company expects to spend approximately $49 million in 2008 in the Gas Pipelines segment for ongoing capital improvements, core maintenance capital projects and expansion, including the projects described above. In 2007, the Company spent $200 million on capital expenditures in the Gas Pipelines segment which is consistent with expectations. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 15.1% ownership interest in EEP and a 41.9% voting interest in EIF. Enbridge manages the day-to-day operations of, and develops and assesses opportunities for each, including both organic growth and acquisition opportunities.

Earnings

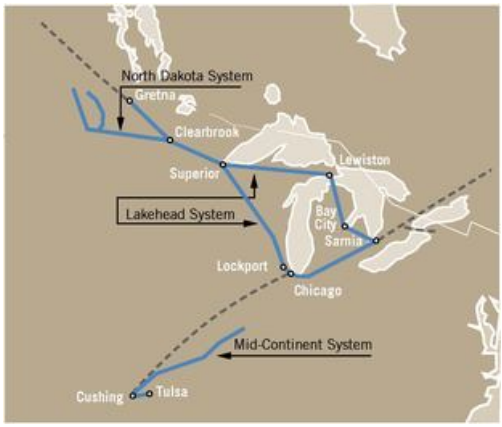
(millions of dollars)	**2007**	2006	2005
Enbridge Energy Partners	**44.0**	43.0	21.7
Enbridge Income Fund	**39.2**	37.8	34.2
Dilution gains	**11.8**	–	8.9
Impact of tax changes	**1.9**	6.0	–
	96.9	86.8	64.8



Sponsored Investments Earnings

(millions of dollars)

Increased earnings from Sponsored Investments in 2007 were primarily a result of the recognition of a dilution gain on a unit issuance in which the Company did not participate.



Enbridge Energy Partners – Liquids Pipelines

Earnings from Sponsored Investments were $96.9 million for the year ended December 31, 2007 compared with $86.8 million in 2006. The increase in earnings was primarily a result of the recognition of a dilution gain on a unit issuance in EEP in which the Company did not participate.

Revenues from Sponsored Investments include only revenues from EIF as the Company equity accounts for its interest in EEP. For the year ended December 31, 2007, revenues were $270.3 million compared with revenues of $254.7 million for the year ended December 31, 2006. The $15.6 million increase in revenue was a result of increased tolls on the Alliance and Saskatchewan Systems as well as a full year contribution from the wind assets purchased in Q4-2006. Fiscal 2006 revenues of $254.7 million were relatively consistent with revenues of $249.0 million for the year ended December 31, 2005.

ENBRIDGE ENERGY PARTNERS

EEP owns and operates crude oil and liquid petroleum transmission pipeline systems, natural gas gathering and related facilities and marketing assets in the United States. Significant assets include the Lakehead System, which is the extension of the Enbridge System in the U.S., natural gas gathering and processing assets in Texas, the mid-continent crude oil system, various interstate and intrastate natural gas pipelines and a crude oil feeder pipeline in North Dakota.

Results of Operations

Earnings from EEP were $44.0 million for the year ended December 31, 2007, consistent with $43.0 million for the year ended December 31, 2006 despite the stronger Canadian dollar. Earnings for fiscal 2007, after adjusting for unrealized derivative fair value gains and losses (losses in 2007 of $6.3 million; gains in 2006 of $6.5 million) and Enbridge's $3.0 million share of the gain on the sale of Kansas Pipeline Company, increased $10.8 million compared to fiscal 2006. The increase reflects Enbridge's larger average ownership interest in 2007 as well as higher incentive income, increased processing margins and higher volumes on principal natural gas and liquids systems that were partially offset by higher operating expenses.

In 2005 EEP issued Class A partnership units which Enbridge did not fully participate in resulting in dilution gains. While new Class C 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%. Enbridge's average ownership interest in 2006 was 13.0%. In the second quarter of 2007, EEP issued partnership units. Because Enbridge did not fully participate in these offerings, dilution gains of $11.8 million resulted and Enbridge's ownership interest in the Partnership decreased from 16.6% to 15.1%. Enbridge's average ownership interest in 2007 was 15.5%.

Earnings from EEP were $43.0 million for the year ended December 31, 2006 compared with $21.7 million for the year ended December 31, 2005. The 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 2006 results also included $6.5 million (net to Enbridge) of unrealized mark-to-market gains (2005 – $5.0 million of losses) on derivative financial instruments that did not qualify for hedge accounting treatment. While Enbridge believes the hedging strategies are sound economic hedging techniques, they do not qualify for hedge accounting and have been accounted for on a mark-to-market basis through earnings.



Enbridge Energy Partners – Gas Pipelines

Distributions

EEP makes quarterly distributions of its available cash to its common unitholders, including Enbridge. Under the Partnership Agreement, Enbridge, as general partner (GP), receives incremental incentive cash distributions, which represent incentive income, on the portion of cash distributions, on a per unit basis, that exceed certain target thresholds as follows:

	Unitholders including Enbridge	Enbridge GP Interest
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 the first three quarters of 2007, EEP paid quarterly distributions of $0.925 per unit (2006 – $0.925 per unit; 2005 – $0.925 per unit). Effective November 2007, EEP increased quarterly distributions to $0.95 per unit. Of the $44.0 million Enbridge recognized as earnings from EEP during 2007, 43% (2006 – 37%; 2005 – 65%) were incentive earnings while 57% (2006 – 63%; 2005 – 35%) were Enbridge's share of EEP's earnings.

Line 3 Incident

In November 2007, an unexpected release and fire on Line 3 of the Lakehead System occurred during planned maintenance near Enbridge's Clearbrook, Minnesota terminal, which resulted in fatalities of two Enbridge employees working on the Line. All pipelines in the vicinity were immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and repair of the pipeline at an estimated economic cost of US$2.6 million to EEP. Lines 1, 2 and 4 were restarted the following day after inspections revealed these lines had not been damaged. 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. Excavation and repairs were completed and the line was returned to service within 5 days. EEP is now working with federal and state environmental and pipeline safety regulators to investigate the cause of the incident.

STRATEGY

EEP intends to increase its distributions primarily through the optimization of existing assets including increased throughput and the expansion of the existing liquids and gas midstream businesses, and potentially through the acquisition of complementary assets.

EEP is benefiting from strong supply growth in both the liquids transportation and gas midstream businesses. Oil sands volume growth will increase throughput and generate opportunities such as the Southern Access and Alberta Clipper expansions, described under Liquids Pipelines. Growing gas infrastructure needs, as a result of production growth and improved technology, are driving new capital investment and volume growth in EEP's principal gas regions. Tightening gas quality specifications are also increasing demand for EEP's treating and processing services. EEP's growing base of gas volumes has allowed it to aggregate volumes to improve margins and develop new take-away pipeline capacity projects.

In addition to the projects described under Liquids Pipelines, EEP is undertaking the following projects:

East Texas System Expansion and Extension (Project Clarity)

Project Clarity includes the construction of a 36-inch diameter pipeline to interstate and intrastate markets. This project is adding 0.7 bcf/d capacity to the current East Texas infrastructure. All phases of the project are complete with the exception of the Kountze, Texas to Orange, Texas stage which is expected to be completed in the first quarter of 2008. Additional capacity to downstream interconnects will increase as compression is added in mid-2008. When complete, the Clarity project will link growing natural gas production and third party storage assets in East Texas with major third party pipelines and markets in the Beaumont, Texas area.

North Dakota System Expansion

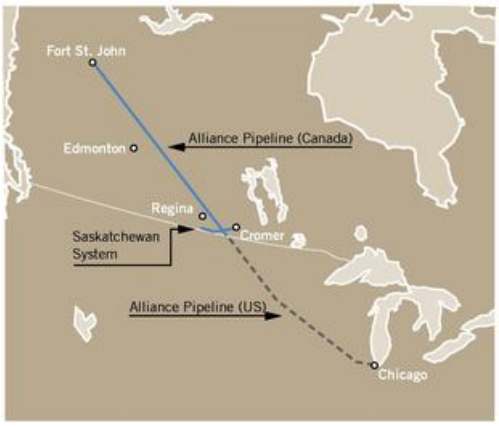
EEP is undertaking a further US$0.2 billion expansion of the Enbridge North Dakota Pipeline System. The expansion, if fully subscribed, is expected to increase system capacity from 110,000 bpd to 161,000 bpd by the end of 2009 and will consist of upgrades to existing pump stations, additional tankage as well as extensive use of drag reducing agents that are injected into the pipeline to increase throughput. The commercial structure for this expansion is a cost of service based surcharge that will be added to the existing tariff rates. Subject to approval from the FERC, this expansion is expected to be completed in early 2010.

BUSINESS RISKS

Supply and Demand

The profitability of EEP depends to a large extent on the volume of products transported on its pipeline systems. The volume of shipments on EEP's Lakehead System depends primarily on the supply of Western Canadian crude oil and the demand for crude oil in the Great Lakes and Midwest regions of the United States and Eastern Canada. EEP expects significantly increased crude oil supplies from the oil sands projects in Alberta. In addition, Enbridge's future plans to provide access to new markets in the Southern United States are expected to increase demand for Western Canadian crude oil, resulting in increased volumes for EEP.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, NGLs and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas. These assets are also subject to competitive pressures from third-party and producer owned gathering systems.



Enbridge Income Fund

Regulation

In the U.S., the interstate and intrastate gas pipelines owned and operated by EEP are subject to regulation by the FERC or state regulators and their revenues could decrease if tariff rates were protested. While gas gathering pipelines are not currently subject to active regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which EEP operates.

Market Price Risk

EEP's gas processing business is subject to commodity price risk for natural gas and NGLs. Historically, these risks have been managed by using physical and financial contracts, fixing the prices of natural gas and NGLs. Certain of these financial contracts do not qualify for cash flow hedge accounting and EEP's earnings are exposed to associated mark-to-market valuation changes.

ENBRIDGE INCOME FUND

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the 100%-owned Enbridge Saskatchewan System, both acquired from the Company in 2003. Alliance Pipeline Canada is the Canadian portion of the Alliance System described in the Gas Pipelines segment above. The Enbridge Saskatchewan System owns and operates crude oil and liquids pipelines systems from producing fields in Southern Saskatchewan and Southwestern Manitoba connecting primarily with Enbridge's mainline pipeline to the United States.

EIF also owns interests in three wind power generation projects purchased from Enbridge in October, 2006 and a business that develops and operates waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

Results of Operations

Earnings from EIF were $39.2 million for the year ended December 31, 2007, comparable with the prior year of $37.8 million.

In 2007, EIF recognized future taxes within entities that will become taxable in 2011 as a result of the enactment of Bill C-52, which is discussed under Tax Fairness Plan. This future tax increase was more than offset by the revaluation of future income tax obligations previously recorded as a result of tax rate reductions in the second and fourth quarters of 2007.

Earnings from EIF were $37.8 million for the year ended December 31, 2006, comparable with the prior year, and reflected modest earnings growth at EIF driven by lower tax on distributions received from EIF.

Tax Fairness Plan

On June 22, 2007, the "Tax Fairness Plan" income trust taxation legislation, Bill C-52, received Royal Assent. Under the enacted legislation, a distribution tax of 29.5% will be imposed on Enbridge Income Fund starting in 2011, provided EIF limits its expansion to "normal growth" prior to 2011. The impact of the Tax Fairness Plan on the Fund's reported earnings was relatively small because most of the assets are rate regulated and future taxes are expected to be included in the approved rates charged to customers in the future. As enacted in its present form, the Tax Fairness Plan will, all other things being equal, likely result in a reduction of cash available for distribution by EIF commencing in 2011. With respect to the limitations on normal growth, the Company believes the Fund should be able to fund its currently identified growth plans within the constraints of the "normal growth" rule.

Incentive and Management Fees

Enbridge receives a base annual management fee of $0.1 million for management services provided to EIF plus incentive fees equal to 25% of annual cash distributions over $0.825 per trust unit. In 2007, the Company received incentive fees of $3.5 million (2006 – $2.4 million, 2005 – $2.1 million). The Company is the primary beneficiary of EIF through a combination of the voting units and a non-voting preferred unit investment and as such EIF is consolidated under variable interest entity accounting rules.

STRATEGY

EIF will maximize the efficiency and profitability of its existing assets, pursue organic growth and expansion opportunities, invest in the expansion activities within its assets including the Saskatchewan System expansion and Alliance Canada receipt facilities expansion as well as three new waste heat power generation projects.

BUSINESS RISKS

Risks for Alliance Pipeline Canada are similar to those identified for Alliance Pipeline US in the Gas Pipelines segment.

Saskatchewan System

The majority of the volumes shipped on the Saskatchewan and Westspur common carrier pipeline systems, key components of the Saskatchewan System, have no specific volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls; however, there is limited pipeline competition in this area. The main competition to the pipelines is from trucking.

EIF's liquids and natural gas pipelines are dependent upon the supply of and demand for crude oil and natural gas from Western Canada.

GAS DISTRIBUTION AND SERVICES

Gas Distribution and Services consists of gas utility operations which serve residential, commercial, industrial and transportation customers, primarily in central and eastern Ontario, the most significant being EGD. It also includes natural gas distribution activities in Quebec, New Brunswick and New York State, the Company's investment in Aux Sable, a natural gas fractionation and extraction business, and the Company's commodity marketing businesses.

EARNINGS

(millions of dollars)	**2007**	2006	2005
Enbridge Gas Distribution	**128.8**	61.8	111.9
Noverco	**18.6**	22.7	28.3
Enbridge Gas New Brunswick	**12.1**	9.8	6.1
Other Gas Distribution	**7.3**	6.5	6.7
Energy Services[1]	**3.6**	10.1	5.0
Aux Sable	**(17.5)**	25.8	5.3
Other[1]	**3.5**	12.6	15.5
Impact of tax changes	**27.7**	28.9	–
	184.1	178.2	178.8

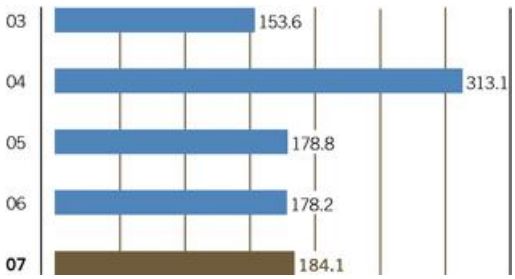
1 *Tidal Energy's results have been reclassified from Other to Energy Services for all periods presented. Other now includes earnings from CustomerWorks.*

Earnings were $184.1 million for the year ended December 31, 2007 compared with $178.2 million for the year ended December 31, 2006. Increased earnings were due to colder than normal weather in 2007 compared with significantly warmer than normal weather in 2006 as well as customer growth in 2007. These increases were partially offset by derivative losses at Aux Sable and lower contributions from the Energy Services businesses.

Earnings were $178.2 million for the year ended December 31, 2006 compared with $178.8 million for the year ended December 31, 2005. Earnings were comparable with 2005, reflecting a number of offsetting factors including higher earnings from Aux Sable due to upside sharing of positive fractionation margins and lower earnings from EGD resulting from both warmer than normal weather and a lower allowed rate of return on common equity.

Revenues for the year ended December 31, 2007 were $10,227.1 million compared with $8,981.6 million for the year ended December 31, 2006. The increase in revenues was a result of a significant increase in volumes transacted by Tidal Energy and, to a lesser extent, an increase in commodity prices for those transactions.

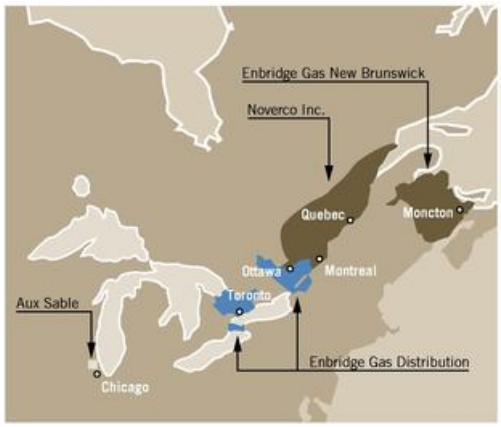
Revenues for the year ended December 31, 2006 were $8,981.6 million compared with $6,947.1 million for the year ended December 31, 2005. The factors contributing to this increase were Tidal Energy commencing U.S. operations in December 2005, resulting in a full year of revenues in 2006, as well as Tidal Energy earning higher revenues due to a higher average price of crude oil in 2006 and EGD's revenues increasing over 2005 as gas prices were high in Q1 of 2006 when the greatest sales volumes were generated.



Gas Distribution and Services Earnings

(millions of dollars)

Gas Distribution and Services earnings in 2007 reflected colder than normal weather in 2007 compared with significantly warmer than normal weather in 2006 as well as customer growth in 2007. These increases were partially offset by derivative losses in Aux Sable and lower contributions from the Energy Services businesses.



Gas Distribution and Services

ENBRIDGE GAS DISTRIBUTION

EGD is a rate-regulated natural gas distribution utility serving customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas as well as the Niagara Peninsula, Ottawa and many other Ontario communities. EGD is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.8 million customers in central and eastern Ontario, Southwestern Quebec and parts of Northern New York State. EGD's operations in Ontario are regulated by the Ontario Energy Board (OEB).

Results of Operations

Earnings for the year ended December 31, 2007 were $128.8 million compared with $61.8 million and $111.9 million for the years ended December 31, 2006 and 2005, respectively. Weather changes over the past three years were the major factor in the earnings fluctuations. In 2007, weather was colder than normal resulting in increased earnings, whereas in 2006 weather was warmer than normal which resulted in lower earnings compared with 2005 when the weather was considered relatively normal.

Earnings in 2007 also increased compared with 2006 because of customer growth, higher operating margins and benefits earned for exceeding targets in the promotion of energy efficient use of natural gas. The decrease in earnings between 2006 and 2005 was also a result of a lower allowed rate of return on common equity, partially offset by a higher rate base.

Normal weather is the weather forecast by EGD in the Toronto area using the forecasting methodology approved by the OEB. Determination of normal weather may also be based on a negotiated settlement with the interveners as part of the regulatory process. This financial measure is unique to EGD and, due to differing franchise areas, is unlikely to be directly comparable to the impact of weather-normalized factors that may be identified by other companies. Moreover, normal weather may not be comparable year-to-year given that the forecasting models are updated annually.

As part of its 2007 rate application, EGD requested a change in the methodology used to calculate normal weather to a 20-year trend method, which is a better predictor of weather. In its decision released on July 5, 2007, the OEB approved the proposed 20-year trend method for calculating normal weather in EGD's main franchise area, the Greater Toronto Area. As a result, the effect of 2007 weather was calculated retroactively to January 1, 2007, based on the approved method, which corresponds to normal weather of 3,617 annual degree days.

Incentive Regulation

Improving the regulatory environment is one of the key strategic thrusts to provide greater operational and organizational flexibility. EGD remained in a cost of service methodology environment in 2007, but will change to Incentive Regulation (IR) methodology in 2008, with 2007 as the base year for a potential

five year plan. Under IR, rates are set based on a formulaic approach, using the base year rates as the starting point for the IR plan term.

The objectives of the IR plan are as follows:

- reduce regulatory costs with less frequent hearings – under normal circumstances, every five years – rather than every year under cost of service;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates.

Rate Application for the IR Term Starting 2008

On February 11, 2008, the OEB approved the Settlement Agreement (the Settlement) filed by EGD which reflected negotiations with ratepayer representatives regarding the type of IR methodology as well as the applicable terms and conditions. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive).

EGD's rate application requested a revenue cap incentive rate mechanism calculated on a revenue per customer basis for the 2008 to 2012 period. The application also requested that revenue per customer be calculated by increasing the prior year's revenue by inflation and reducing it by a productivity challenge factor which would motivate EGD to increase productivity. Revenue could also include specific categories of expenses to enable EGD to recover cost increases beyond management's control.

This IR methodology adjusts revenues every year, not rates, and relies on an annual process to forecast volume and customer additions. Unlike the cost of service methodology used in prior years, the concepts of rate base and return on rate base are not relevant for the purpose of setting rates. Under IR, EGD will have the opportunity to benefit from productivity enhancements and incremental revenues.

The key terms of the Settlement are summarized as follows:

Revenue per Customer Cap – The Settlement allows for the annual reset of volumes, with revenues increasing proportionately with the growth in the number of customers. The revenue per customer cap will continue to minimize EGD's exposure to declining average use of natural gas while providing incentive for EGD to continue growing its customer base.

Earnings Sharing – To align the interests of customers with EGD, an earnings sharing mechanism forms part of the Settlement. To the extent the actual utility return on equity represented by normalized earnings (i.e. excluding the effects of weather) (ROE) exceeds a notional allowed utility rate of return on equity (NROE) by certain prescribed thresholds, the excess will be shared with customers.

Adjustments – The Settlement provides for the recovery of capital invested in new power generation laterals. EGD is also allowed to recover expenses above a defined threshold, to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

Off Ramps – An OEB review will be triggered if EGD's ROE varies more than 300 basis points (either negatively or positively) relative to the NROE.

EGD applied for and, on December 18, 2007, was granted approval for interim rates effective January 1, 2008 and expects the OEB's final 2008 rate order will be applied retroactively to January 1, 2008.

2007 and 2006 Rates

The key elements of the 2007 and 2006 decisions are summarized below:

Regulatory year	Approved 2007	Approved 2006
Rate base *(millions of Canadian dollars)*	$3,745.7	$3,633.6
Deemed common equity for regulatory purposes	36%	35%
Rate of return on common equity	8.39%	8.74%

The OEB released its final decision relating to EGD's 2007 cost of service rate application on July 5, 2007. The new rates approved by the OEB's decision resulted in an overall increase in rates of approximately 3.5% for the average residential customer. EGD was granted a 1% increase in the equity component of its deemed capital structure to 36% from 35% reflecting changes in EGD's business risk environment and financial risk position. In addition, the new 20-year trend method to calculate normal weather was approved. Finally, EGD was directed to cease its risk management program, which utilized price swaps, calls and collars to manage the volatility in the price of natural gas. Consistent with prior years, changes in the price of natural gas flow through to the customer.

EGD's 2007 and 2006 rates were established pursuant to a cost of service methodology that allowed revenues to be set to recover EGD's forecast costs. Forecast costs included gas commodity and transportation, operation and maintenance, depreciation, municipal taxes, income taxes, and the debt and equity costs of financing the rate base. The rate base is EGD's investment in all assets used in gas distribution, storage and transmission as well as an allowance for working capital. Under the cost of service model, it is EGD's responsibility to demonstrate to the OEB the prudence of the forecast costs.

The rate base is financed through a combination of debt and equity. For the debt portion, interest expense incurred by EGD is recovered in rates. For the equity portion, the OEB sets the rate of return that EGD may recover in rates. The allowed rate of return on equity for EGD is based on the forecast yield on Canadian government long-term bonds.

Effects of Rate Regulation

As EGD is subject to rate-regulation, either in a cost of service or incentive model, there are circumstances where revenues recognized do not match the amounts billed. Certain amounts are deferred for recovery or refund with the approval of the regulator and are not included in revenues or expenses that would otherwise be recognized in the income statement, in the absence of rate regulation.

The regulator allows certain variances between approved and actual expenses to be recovered from, or refunded to, customers in future periods. The deferred amounts are not included in the calculation of rates billed to customers. While there are numerous deferral accounts approved by the regulator, the difference between the price of gas approved by the regulator and the actual cost of gas purchased is the most significant. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the income statement captures only the approved cost of gas and the related revenue rather than the actual cost of gas and related revenue. EGD has no exposure to changes in the cost of gas as it is a flow through cost that is passed to the ratepayer.

STRATEGY

EGD's vision is to be North America's leading energy distribution and services company. To achieve this vision, EGD has outlined the following strategic objectives:

- focus on safety, operational excellence and customer satisfaction;

- grow core utility earnings;
- improve return on invested capital; and
- develop human resources.

One of EGD's major strategic initiatives is to evaluate the potential changes of the regulatory environment in planning and maximizing future operational and organizational flexibility. EGD has continued regulatory filings through the cost of service process for 2007 to ensure an appropriate base is in place for a 2008 IR plan. At the same time, EGD plans to transform the business for IR, including rationalizing capital investment, increasing productivity and identifying top line enhancements while maintaining system reliability and safety.

Customer Growth

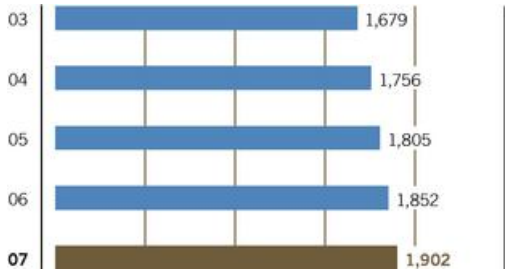
Another major strategic initiative is enhancing customer growth. EGD added over 43,000 new customers in the year ended December 31, 2007 (over 47,000 in the year ended December 31, 2006). EGD expects to add 40,000 to 45,000 customers in 2008. In addition to traditional gas distribution growth expected, new earnings growth opportunities include investment in new laterals for power generation, fuel switching, implementation of turboexpanders on the gas distribution system, development and delivery of energy efficiency programs and billing services for third parties as well as development of new gas load balancing options.

Storage Project

In April 2007, EGD signed storage contracts to provide daily services totaling 2.8 million gigajoules, or approximately 2.6 billion cubic feet (bcf), of storage capacity, including 10 or 20-day storage service with firm year-round withdrawal and injection levels. Based on a final OEB decision to cease regulating prices for new storage services offered, EGD will proceed with development of the project.

Customer Care and Customer Information System Agreements

In April 2007, EGD entered into five-year customer care services contracts with third party service providers for meter reading, billing, billing administration, call handling and collections. The total cost of the contracts is approximately $274 million over the five year term. EGD is planning to have a new CIS system in service by July 2009 to meet regulatory requirements and to meet the need for a more robust and technologically up-to-date system. The OEB has approved a six-year rate recovery arrangement for the customer care services and a ten-year recovery of the $119 million in capital to be invested in the new CIS.



Gas Distribution and Services – Number of Active Customers
(thousands)
EGD added over 43,000 new customers in 2007 and EGD expects to add 40,000 to 45,000 customers in 2008. The 2004 number reflects the 15-month period reported as part of Enbridge's change in financial reporting to eliminate consolidation of gas distribution operations on a quarter lag basis.

CAPITAL EXPENDITURES

EGD's capital expenditures in recent years have averaged approximately $300 million per year, but are expected to increase in 2008 to $407 million as EGD completes laterals for new power generating facilities, and builds its CIS system discussed above.

LEGAL PROCEEDINGS

Bloor Street Incident

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred on Bloor Street West in Toronto on April 24, 2003. On October 25, 2007, all of the TSSA and OHSA charges laid against EGD were dismissed by the Ontario Court of Justice. The decision has been appealed by the Crown to the Ontario Superior Court of Justice. Although a timetable for the appeal has not yet been set by the Court, the Company expects that it will be heard during 2008. The maximum possible fine upon conviction on all charges would be approximately $5.0 million in the aggregate.

EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion is also possible. The majority of the civil actions have been settled and EGD does not expect the outstanding civil actions to result in any material financial impact.

Harper Gardens Incident

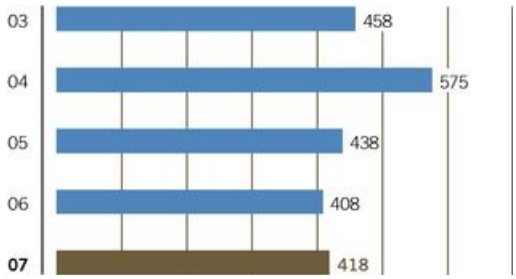
In February 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A gas fitter in the home at the time of the explosion was seriously burned. Several public authorities are investigating the incident. EGD has also been named as defendant in civil actions related to the explosion, but does not expect these actions to result in any material financial impact.

BUSINESS RISKS

The risks identified below are specific to EGD. General risks that affect the Company as a whole are described under Risk Management.

Regulatory Risk

Through the regulatory process, the OEB approves the return on equity that EGD is allowed to include in rates, in addition to various other aspects of utility operations. The formula currently approved by the



Volume of Gas Distributed
(billion cubic feet)
Gas volumes distributed reflect the growing number of active customers and the impact each year of warmer than normal or colder than normal weather. The 2004 volumes reflects the 15-month period.

OEB for determination of the return on equity is based on the OEB's current risk assessment of EGD for the 2007 fiscal year and is effectively embedded into rates over the IR period.

EGD expects the implementation of certain factors in the IR formula will permit it to recover certain costs that are beyond management control, but are necessary for the maintenance of its services. Furthermore, EGD has requested a mechanism to end the IR plan and return to cost of service if there are significant and unanticipated developments (i.e., natural disasters, war, high rates of inflation, etc.) that threaten the sustainability of the IR plan. To the extent the OEB denies recovery of any such costs, EGD is at risk.

EGD does not profit from the sale of the natural gas commodity nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and will request interim rate relief that will allow it to recover or refund the natural gas commodity cost differential.

EGD has a quarterly rate adjustment mechanism in place for the natural gas commodity. This allows for the quarterly adjustment of rates to reflect changes in natural gas commodity prices. Adjustments are subject to prior approval by the OEB.

Volume Risks

Since customers are billed on a volumetric basis, EGD's ability to collect its total revenue requirement depends on achieving the forecast distribution volume established in the rate-making process. Under IR, volume forecasts will be reviewed and approved by the OEB annually. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing or competitive energy sources and the growth of customers.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 78% (2006 – 77%) of total distribution volume. Weather during the year, measured in degree days, has a significant impact on distribution volume as a major portion of the gas distributed to these two markets is used ultimately for space heating. In 2007, the winter months were colder than forecast, resulting in a favourable weather related volume variance of 11.6 bcf.

Distribution volume may also be impacted by the increased adoption of energy efficient technologies along with more efficient building construction that continues to place downward pressure on annual average consumption. Average annual residential gas usage has declined by 1.3% per annum over the last 10 years, reflecting consistent customer conservation efforts.

Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volumes distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the approved return on equity due to other forecast variables such as the mix between the higher margin residential and commercial sectors, and lower margin industrial sector.

Franchise Rights

EGD has an exclusive right to serve all end users within its franchise area, under its franchise agreements. Similar franchise agreements in adjacent areas are held by peer companies such as Union Gas Limited (UGL). On January 6, 2006, the OEB granted Greenfield Energy Corporation, a potential power-plant customer of UGL, the right to physically bypass UGL's distribution network within UGL's franchise area, in order to serve its own power-plant. The OEB's decision to not uphold exclusive franchise rights of a local distribution utility in Ontario was unprecedented. However, the OEB characterized this decision as transitional, and set up a rates proceeding which assessed the service requirements of gas fired generation in the province of Ontario. The OEB decision from this rates proceeding was issued in November 2006. EGD believes the new rates are robust and would make physical bypass of EGD's system unattractive to gas fired power generation plants. However, the OEB decision did not preclude any party from seeking approval from the OEB to build its own pipeline and bypass the local distribution utility. EGD objects strongly to the concept that any such franchise violation is acceptable and will object if any similar proposal arises in the EGD franchise area.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 32.1% of the common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71.0% of Gaz Metro Limited Partnership (Gaz Metro), a gas distribution company operating in the province of Quebec and the state of Vermont. Gaz Metro also has a 50% interest in TQM Pipeline, which transports natural gas in Quebec, and is partnering with the Company on the Rabaska LNG project (described under Other Natural Gas Distribution Strategies below). Noverco also has an investment in the common shares of Enbridge resulting in dividend and earnings elimination adjustments at Enbridge.

Results of Operations

Noverco earnings were $18.6 million for the year ended December 31, 2007 compared with $22.7 million for the year ended December 31, 2006. The $4.1 million decrease in earnings is a result of the recognition of a $4.0 million dilution gain in 2006 from a Gaz Metro unit issuance in which Noverco did not participate.

Noverco earnings were $22.7 million for the year ended December 31, 2006 compared with $28.3 million for the year ended December 31, 2005. Earnings decreased due to a $7.3 million dilution gain in 2005, which resulted from a Gaz Metro unit issuance in which Noverco did not participate, compared with a dilution gain of $4.0 million in 2006. Excluding dilution gains, earnings from Noverco were lower in 2006 as 2005 included a future income tax recovery stemming from the receipt of a significant cash dividend.

Weather variations do not affect Noverco's earnings as Gaz Metro is not exposed to weather risk. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%.

ENBRIDGE GAS NEW BRUNSWICK

The Company owns 70.8% of, and operates, Enbridge Gas New Brunswick (EGNB), which owns the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 8,200 customers. Approximately 645 kilometres (400 miles) of distribution main has been installed with the capability of attaching approximately 29,000 customers.

Results of Operations

EGNB earnings were $12.1 million for the year ended December 31, 2007 compared with $9.8 million for the year ended December 31, 2006. Earnings were higher in 2007 due to the impact of the increasing ratebase.

EGNB earnings were $9.8 million for the year ended December 31, 2006 compared with $6.1 million for the year ended December 31, 2005. Earnings were higher in 2006 as debt was settled through the issuance of equity during the third and fourth quarters of 2005 resulting in a higher equity base throughout 2006.

EGNB is regulated by the New Brunswick Energy and Utilities Board (EUB). As it is currently in the development period, EGNB's cost of service exceeds its distribution revenues. The EUB has approved the deferral of the difference between distribution revenues and the cost of service during the development period for recovery in future rates. This recovery period is expected to start in 2010 and end no sooner than December 31, 2040. On December 31, 2007, the regulatory deferral asset was $117.7 million (2006 – $101.8 million).

ENERGY SERVICES

Energy Services includes Gas Services and Tidal Energy, the Company's energy marketing businesses.

Gas Services markets natural gas to optimize Enbridge's commitments on the Alliance and Vector Pipelines. It also has a growing business of providing fee-for-service arrangements for third parties, leveraging its marketing expertise and access to transportation capacity. Capacity commitments as of December 31, 2007 were 32.2 mmcf/d on the Alliance Pipeline (2.0% of total capacity) and 162.1 mmcf/d on Vector Pipeline (16.4% of total capacity). Capacity commitments as of December 31, 2006 were 31.6 mmcf/d on the Alliance Pipeline (2.4% of total capacity) and 159.2 mmcf/d on Vector Pipeline (15.9% of total capacity).

Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago, for Alliance Pipeline, and between Chicago and Dawn, for Vector Pipeline. To the extent the cost of transportation on these two pipelines exceeds the gas commodity basis differential, earnings will be negatively affected.

Tidal Energy provides crude oil and NGLs marketing services for the Company and its customers in a full range of condensate and crude oil types including light sweet, light and medium sours and several heavy grades. Tidal Energy transacts at many of the major North American market hubs and provides its customers with a variety of programs including flexible pricing arrangements, hedging programs, product exchanges, physical storage programs and total supply management, through the analysis and implementation of different transportation options, reduced quality differentials and tariff structures, and utilizing risk management pricing options. Tidal Energy's business involves buying, selling and storing large quantities of crude oil. Tidal Energy is primarily a physical barrel marketing company and in the course of its market activities, physical receipt or delivery shortfalls can create modest commodity exposures. Any open positions created from this physical business are tightly monitored by, and must comply with, the Company's formal risk management policies.

Results of Operations

Earnings from Energy Services were $3.6 million for the year ended December 31, 2007 compared with $10.1 million for the year ended December 31, 2006. The decrease in earnings is due to outstanding storage transactions in Tidal Energy that were negatively impacted by rising crude oil prices. Tidal

Energy buys crude oil, stores it and sells it forward at a higher price, locking in a profit on the transaction. However, during the life of the transaction, Tidal Energy may hold the oil held in storage and use it to satisfy a new forward sale at an additional deferred profit. Tidal Energy then purchases oil at spot prices to satisfy the original sale transaction. As a result, losses will be recognized in periods of rising oil prices and profitability will be deferred until the original transaction settles.

AUX SABLE

Enbridge owns 42.7% of Aux Sable, a NGLs extraction and fractionation business near Chicago. Aux Sable owns and operates a plant at the terminus of the Alliance System. The plant extracts NGLs from the energy-rich natural gas transported on the Alliance System, as necessary, to meet the heat content requirements of local distribution companies, which require natural gas with less NGLs, or lower heat content, and to take advantage of positive commodity price spreads.

Aux Sable has an agreement with BP Products North America Inc. to sell its NGLs production to BP. In return, BP pays Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, BP compensates Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP supplies, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and is responsible for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement is for an initial term of 20 years, commencing January 1, 2006 and may be extended by mutual agreement for 10-year terms. If cumulative losses exceed a certain limit, BP will have the option to terminate the agreement, although Aux Sable has the right to reduce such losses to avoid termination.

Results of Operations

Loss for the year ended December 31, 2007 was $17.5 million compared with earnings of $25.8 million for the year ended December 31, 2006. Aux Sable's 2007 reported earnings included $28.1 million of unrealized derivative fair value losses related to the Company's share of 2008 contingent upside sharing revenue. Upside sharing revenue is earned on natural gas processing margins in excess of certain thresholds. Derivative transactions used in 2007, and in place for 2008, provide cash flow predictability which is important to the Company in this period of significant project financing. The stronger Canadian dollar also resulted in a decrease in earnings in 2007.

Earnings for the year ended December 31, 2006 were $25.8 million compared with earnings of $5.3 million for the year ended December 31, 2005. Fractionation margins were very positive throughout 2006 and as a result, earnings from the upside sharing mechanism account for the majority of earnings from Aux Sable.

OTHER

Other earnings were $3.5 million in 2007 compared with earnings of $12.6 million in 2006. Other includes CustomerWorks which generated lower earnings in 2007 because, pursuant to an OEB recommendation, customer care services related to EGD were transitioned to a third party service provider.

STRATEGY

Other Natural Gas Distribution Strategies

Enbridge intends to pursue natural gas business development opportunities complementary to the existing gas distribution and services businesses through:

- developing LNG regasification projects and related pipeline infrastructure;
- pursuing marketing and storage opportunities that optimize existing assets; and
- exploring gas-fired generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets. The approach is to slowly build this business and utilize partners to share development risks.

Further to this strategy, Enbridge is developing a number of projects, which are described below.

Rabaska LNG Facility

Enbridge, Gaz Metro and Gaz de France are continuing development of the $0.8 billion Rabaska LNG terminal to be located on the St. Lawrence River in Levis, Quebec. Environmental and marine applications have been reviewed by Federal and Provincial government agencies and positive reports issued. Provincial government project and land use approval was received in October 2007 and Federal approval is expected shortly. Discussions are in progress with potential LNG suppliers regarding long-term terminal use arrangements.

Ontario Wind Project

Enbridge is developing approximately 182 megawatts of wind power in the Municipality of Kincardine on the eastern shore of Lake Huron in Ontario. In July 2007, the Ontario Municipal Board and the Ontario Ministry of the Environment ruled in favour of the construction of Enbridge's Ontario Wind Project. This was the final approval required and subsequently construction has commenced with access roads, turbine foundations, electrical sub-station and utility transmission lines. On completion, the $0.5 billion project will be one of the largest wind power projects in Canada. Enbridge has entered into a 20-year electricity purchase agreement with the Ontario Power Authority for all the power produced by the project.

The project is expected to begin producing electricity during the latter half of 2008 and be fully operational in early 2009.

Netthruput

In 2007, the Company and its partner in Netthruput (NTP) entered into an agreement with the TSX Group granting the TSX Group the option to purchase NTP, an internet-based crude oil trading and clearing platform. The Company received $9.5 million proceeds from the sale of the option, which may be exercised at a time after March 15, 2009 for a price between $40 million and $95 million depending on NTP's 2008 net earnings. The agreement also provides the Company and its partner in NTP an option to sell NTP under the same terms to the TSX Group. The Company has a 52% ownership interest in NTP.

CAPITAL EXPENDITURES

Capital expenditures in Gas Distribution and Services, excluding EGD, were $215 million in 2007 and are expected to be approximately $261 million in 2008.

INTERNATIONAL

International includes earnings from the Company's 25% interest in Compañia Logística de Hidrocarburos CLH, S.A. (CLH), Spain's largest refined products transportation and storage business, and its investment in, and management of, Oleoducto Central S.A. (OCENSA), a crude oil pipeline in Colombia. Other includes administration and business development.

EARNINGS

(millions of dollars)	**2007**	2006	2005
CLH	**65.6**	54.5	61.6
OCENSA/CITCol	**32.9**	33.9	32.8
Other	**(3.4)**	(5.2)	(7.0)
	95.1	83.2	87.4

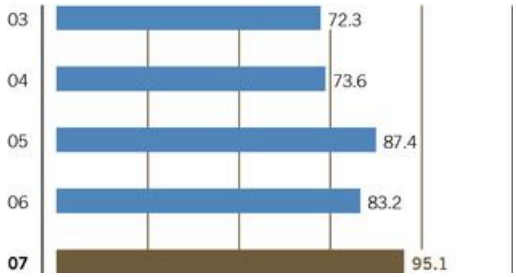
Earnings for the year ended December 31, 2007 were $95.1 million compared to $83.2 million for the year ended December 31, 2006. Earnings in 2007 included a $5.2 million gain on the sale of land within CLH. The increase in earnings was also due to stronger operating earnings in CLH as a result of higher transported volumes, an increase in operating revenues from complimentary businesses, lower income taxes as a result of a tax rate reduction in Spain and lower business development costs in Other.

Earnings for the year ended December 31, 2006 were $83.2 million compared with $87.4 million for the year ended December 31, 2005. Earnings from CLH for 2005 included a $7.6 million gain on the sale of land, recorded in the fourth quarter.

CLH

The primary activity of CLH is the storage and shipment of refined products through a comprehensive distribution network located throughout Spain. Earnings are based on a fee for service tariff, adjusted annually for inflation, and are dependent on throughput volumes and storage levels.

CLH is the primary basic logistics distribution network for refined products in Spain and provides services on an open access, non-discriminatory basis. The system consists of over 3,400 kilometres (2,113 miles) of pipelines and 38 storage facilities located throughout the country. CLH provides refined product distribution to locations not connected to the pipeline system through its own fleet of tanker trucks and chartered tanker ships. CLH also provides long-term storage for strategic reserves of refined products to both operators and a Spanish Government Agency, CORES, which is responsible for



International Earnings
(millions of dollars)
International earnings in 2007 included a $5.2 million gain on the sale of land within CLH. Increased earnings were also due to stronger operating earnings in CLH.

managing the country's strategic hydrocarbon reserves. In addition, CLH offers secondary distribution services, the most significant being the services provided through CLH Aviation, which handles aviation fuel at airport locations throughout Spain. This business includes the storage of aviation fuel, loading of aircraft refueling units and the refueling of aircraft. New policies issued by the Spanish airport authority (AENA) to promote competition allow for new non-CLH operators to enter the aircraft-refueling segment of this business. While CLH's share of this segment of the market may reduce over time, its participation in the aviation fuel business is expected to continue. CLH's pipeline facilities are connected to the country's eight crude oil refineries and to major coastal port locations where most imports of crude oil and refined products into Spain are first delivered.



Spain – CLH

Earnings from CLH are directly impacted by the demand for refined products, including gasoline, diesel, jet fuel and other transportation fuels. Economic growth in Spain over the last decade has been among the highest in the European Union, which has led to increasing demand for energy, including refined products. The central region of the country, in and around Madrid, has seen the largest growth in demand. CLH is in the process of expanding its system over the next several years in order to meet the continued growth expected in this region and to deliver incremental volumes expected from domestic refinery expansions, located primarily in the south of the country. This expansion, which includes an increase in storage capacity and looping of both the northern and southern main lines, is being constructed in phases to match the expected growth in volumes.

OCENSA/CITCol

The Company owns a 24.7% interest in OCENSA, an investment on which the Company earns a fixed return. OCENSA is one of two main crude oil export pipelines within Colombia. Through a 100% owned entity, CITCol, the Company manages the pipeline and earns a fee for this service, which includes incentives for operating performance. In 2007, OCENSA made the final payments with respect to its original US$1.6 billion project debt financing. With no further debt servicing obligations OCENSA may opt to begin returning the Company's initial equity capital starting in 2009, in accordance with the terms of the project agreements.

STRATEGY

The Company will de-emphasize the pursuit of new acquisition opportunities outside of North America, due to the competitive environment and the significant number of opportunities available in the North American liquids business. On February 13, 2008, Enbridge announced it is evaluating strategic alternatives for monetizing its investment in CLH. Proceeds from any monetization of the CLH investment would be applied toward funding the Company's growth projects.



Colombia – OCENSA

BUSINESS RISKS

The International business is subject to risks related to political and economic instability, currency volatility, market and supply volatility, government regulations, foreign investment rules, security of assets and environmental considerations. The Company assesses and monitors international regions and specific countries on an ongoing basis for changes in these risks. Risks are mitigated by a combination of Enbridge's governance involvement, contractual arrangements, influence in operation of the assets, regular analysis of country risk as well as foreign currency hedging and insurance programs.

CORPORATE

(millions of dollars)	**2007**	2006	2005
Corporate	**(63.0)**	(82.2)	(63.9)
Impact of tax changes	**30.2**	14.0	–
	(32.8)	(68.2)	(63.9)

The Corporate segment includes corporate financing costs, corporate development activities and other corporate costs not attributable to a specific business segment.

Corporate costs totaled $32.8 million for the year ended December 31, 2007, compared with $68.2 million in 2006. After adjusting for the impact of favorable legislated tax changes, Corporate costs decreased $19.2 million due to lower interest expense resulting from decreased average debt balances throughout 2007 as a result of the equity issuance in the first quarter. As well, expenditures on corporate development activity decreased because of the Company's focus on organic growth.

Corporate costs were $68.2 million for the year ended December 31, 2006 compared with $63.9 million for the year ended December 31, 2005. The increase in Corporate costs was due to a number of factors including higher interest expense as a portion of the Company's floating rate debt was repaid through the issuance of long-term fixed rate debt as well as higher business development activity and the impact of a strong labour market on compensation expense.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to generate sufficient cash from operations and debt issuances to fund liabilities as they become due, finance budgeted investing activity and pay common share dividends throughout 2008. Additional liquidity, if necessary, is available under committed credit facilities or through access to the capital markets. At December 31, 2007, the Company had $5.6 billion (2006 – $3.3 billion) of committed credit facilities, of which $2.4 billion was drawn or used to backstop commercial paper. On January 4, 2008, a new credit facility was arranged for general corporate purposes and to fund the

construction of organic growth projects, such as Alberta Clipper Pipeline. The addition of this facility increased the Company's credit facilities to $6.6 billion subsequent to year-end.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The debt to capitalization ratio at December 31, 2007, including short-term borrowings, but excluding non-recourse short and long-term debt, strengthened to 62.7%, compared with 64.6% at the end of 2006 and 66.5%, compared with 68.6% at the end of 2006 including non-recourse debt.

The Company's current liabilities routinely exceed current assets. Current liabilities include current maturities of long-term debt, which are typically refinanced with long-term debt. Excluding current maturities of long-term debt, the Company does not have a working capital deficit.

OPERATING ACTIVITIES

Cash from operating activities increased to $1,378.7 million for the year ended December 31, 2007 from $1,297.7 million for the year ended December 31, 2006 and $947.0 million for the year ended December 31, 2005.

(millions of dollars)	**2007**	2006	2005
Earnings net of non-cash items	**1,358.0**	1,171.0	1,300.9
Changes in operating assets and liabilities	**20.7**	126.7	(353.9)
Cash Provided by Operating Activities	**1,378.7**	1,297.7	947.0

Cash provided by earnings net of non-cash items, was $1,358.0 million for the year ended December 31, 2007, compared with $1,171.0 million and $1,300.9 million for 2006 and 2005, respectively. The increased earnings from operating activities resulted primarily from higher earnings at EGD due to colder than normal weather in 2007.

Changes in operating assets and liabilities generated $20.7 million in 2007, compared with $126.7 million in the prior year. This decrease primarily resulted from increased accounts receivable at EGD at December 31, 2007 due to the relatively colder weather experienced during the final billing periods of the year. Changes in operating assets and liabilities were $480.6 million higher in 2006 compared with 2005. The increase was due primarily to the impact of a declining trend in the price of natural gas in the latter half of 2006 compared with an increasing trend in 2005.

INVESTING ACTIVITIES

Cash used for investing activities for the year ended December 31, 2007 was $2,255.9 million compared with $1,580.0 million in 2006. In 2007, the Company had increased capital expenditures, primarily due to growth projects such as Southern Lights, the Waupisoo Pipeline and Ontario Wind Project as well as core maintenance expenditures incurred primarily at EGD and Enbridge System. There were no acquisitions in the current year.

In 2006, the Company spent $1,580.0 million on investing activities compared with $876.5 million in 2005, an increase of $703.5 million. The majority of the increase was due to expenditures on property, plant and equipment, including the commencement of capital expenditures on a number of Liquids Pipelines projects. In addition, $381.6 million of the increase resulted from the investment in EEP and the acquisition of an interest in Olympic Pipeline.

FINANCING ACTIVITIES

In 2007, the Company generated $904.2 million through financing activities compared with $268.1 million in 2006 and cash used for financing activities of $22.1 million in 2005. This increase in cash flow from financing activities is primarily a result of the equity issuance and drawing on the new Southern Lights credit facility, which are discussed below.

Financing activities in 2007 included the issuance of US$400.0 million of long-term debt in the first quarter, US$650.0 million in the second quarter and issuance of $200.0 million of medium-term notes in the fourth quarter. These financing activities were used to refinance long-term debt maturities and to finance new growth projects at attractive long-term interest rates.

Short-term borrowings at EGD are used primarily to finance working capital, including inventory. Short-term debt financing increased in 2007 primarily to finance new growth projects offset by a decrease in short term debt at EGD as a result of lower working capital requirements.

In 2007 the Company expanded its available liquidity through credit facility expansions and additions. Specifically, the Company increased the size of the existing facilities by $1.9 billion. On August 31, 2007, a new US$500.0 million credit facility with a 364-day term was arranged to fund project costs directly related to the Southern Lights Project.

During 2006, the Company issued $1,125.0 million of new long-term debt (2005 – $1,020.1 million) in the form of medium-term notes and repaid $400.0 million in medium-term notes which matured during 2006. EGD's short-term borrowings were $266.9 million lower in 2006 compared with 2005, reflecting the impact of decreasing natural gas prices. This decrease in short-term borrowings was partially offset by an increase in short-term debt to finance capital expenditures and investments.

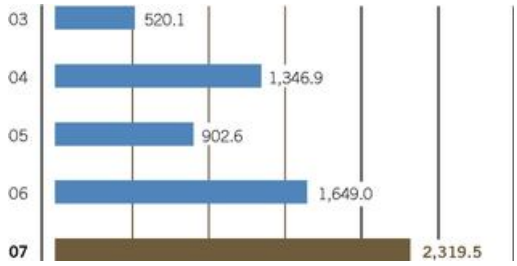
Dividends on common shares increased again in 2007 due to an increased number of common shares outstanding and a higher dividend rate.

Equity Issuance

On February 2, 2007, Enbridge closed the issuance of 13.5 million common shares for $38.75 per share to the public and issued 1.5 million common shares to Noverco for $38.75 per share, which maintains Noverco's ownership interest in Enbridge at approximately 9.5%. Net proceeds from both offerings totaled $566.4 million.

Preferred Securities

The Company redeemed its $200.0 million, 7.8% Preferred Securities on February 15, 2007.



Capital Expenditures, Investments and Acquisitions

(millions of dollars)

The 2007 total for capital expenditures, investments and acquisitions reflects increased capital expenditures primarily due to growth projects such as Southern Lights, the Waupisoo Pipeline and Ontario Wind Project as well as core maintenance expenditures incurred primarily at EGD and Enbridge Systems.

Expected Capital Expenditures

The numerous organic growth projects and other growth initiatives described in the business unit sections will require capital funding. The Company also requires capital for ongoing core maintenance and capital improvements in many of its businesses. In total, Enbridge expects to spend approximately $3.7 billion during 2008 on capital projects and maintenance. The Company expects to finance these expenditures through cash from operating activities and additional external financing. The Company may also raise capital through the monetization or disposition of selected businesses. Enbridge announced February 13, 2008 that the Company is evaluating strategic alternatives for monetizing its investment in CLH.

The decision to finance with debt or equity is based on the capital structure for each business and the overall capitalization of the consolidated enterprise. Certain of the regulated pipeline and gas distribution businesses issue long-term debt to finance capital expenditures. This external financing may be supplemented by debt or equity injections from the parent company. Debt, and equity when required, has been issued to finance business acquisitions, investments in subsidiaries and long-term investments.

Funds for debt retirements are generated through cash provided from operating activities as well as through the issue of replacement debt.

Payments due for contractual obligations over the next five years and thereafter are as follows:

(millions of dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt[1]	8,318.3	604.5	1,054.3	400.0	6,259.5
Non-recourse long-term debt[1]	1,524.7	59.5	340.1	181.3	943.8
Capital and operating leases	166.2	12.1	27.1	28.7	98.3
Long term contracts[2,3]	2,505.8	935.9	900.4	381.9	287.6
Total Contractual Obligations	12,515.0	1,612.0	2,321.9	991.9	7,589.2

1 *Excludes interest component.*

2 *Approximately $947.6 million of these contracts are commitments for materials related to the construction of Liquids Pipelines projects.*

3 *Contracts totaling $252.0 million are with proportionately consolidated joint venture entities.*

SENSITIVITY ANALYSIS

The Company's earnings will fluctuate with changes in certain market prices, volumetric throughput and with weather.

Enbridge quantifies and manages its market price risks using an earnings at risk (EaR) metric. Under the Company's EaR policy, the maximum adverse change in the 12 month forward earnings forecast (due to movements in market prices over a one-month period of time) will not exceed 5% of earnings (based on a 95% confidence interval). On December 31, 2007, the Company's EaR was 2.8% (2006 – 2.9%) of 12 month forecasted earnings.

The following table shows the effect that changes in certain key financial market variables has on earnings. These sensitivities are approximations based on business conditions as of December 31, 2007 and may not be applicable to other periods.

Factor	Change	After-Tax Earnings Impact
Exchange rate (CAD Dollar to U.S. Dollar)	CAD$0.01	$1.5 million
Exchange rate (CAD Dollar to euro)	CAD$0.01	$0.4 million
Interest rate	0.5%	$3.0 million

Interest rate fluctuations are captured in the Company's EaR metric; however, under GAAP the impact of foreign currency fluctuations on earnings from foreign subsidiaries cannot be hedged. As such, these fluctuations have been excluded from the Company's EaR metric. The Company does hedge the foreign currency risk on cash distributions it receives from foreign currency denominated subsidiaries. Unhedged foreign currency cash flows are incorporated in the EaR metric.

Transportation volumetric risks are managed through tariff agreements. Most of the Company's tariff agreements provide for take-or-pay or throughput insensitivity.

Weather is a significant driver of delivery volumes at EGD, given that a significant portion of EGD's customers use natural gas for space heating. Weather, measured in terms of degree day deficiency, directly impacts EGD's earnings as noted below. Degree-day is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	17 degree days	1 billion cubic feet
Volume	1 billion cubic feet	$1.2 million (after-tax)

In recent years weather has impacted earnings by a larger magnitude than the above sensitivities would suggest. This results from the unusual pattern of distribution of degree days during the year and their relative effectiveness. Degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

RISK MANAGEMENT

The Company's business activities are subject to execution, financing, market price, credit and operating risks. The Company has formal risk management policies, processes and systems designed to mitigate these risks.

EXECUTION RISK

The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third party opposition, government approvals, cost escalations, construction delays and shortages (collectively Execution Risk). The Company's significant growth plans may strain its resources and are subject to high cost pressures that prevail in the North American energy sector. Early stage project risks include right-of-way procurement, special interest group opposition, crown consultation, environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to slow delivery of materials, contractor non-performance, weather conditions and shortages due to the overheated energy sector may impact project development. Labour shortages, inexperience and productivity issues may also affect the successful completion of the projects.

The Company has a clearly defined management and governance structure for all major projects. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements. The Company's emphasis on corporate social responsibility promotes positive relationships with landowners, aboriginal groups and governments. Cost tracking and centralized purchasing is used on all major projects. Strategic relationships have been developed with suppliers and contractors. Compensation programs, communications and the working environment are aligned to attract, develop and retain qualified personnel. In early 2008, the Company made changes in its senior management team structure which further emphasize successful project execution.

FINANCING RISK

The Company's financing risk relates to the price volatility and availability of debt and equity to finance organic growth projects and refinance existing debt maturities. This risk is directly influenced by market factors, as Canadian and U.S. debt and equity market conditions can change dramatically, affecting capital availability.

To address this risk, the Company ensures that it can readily access either the Canadian or U.S. public capital markets by maintaining current shelf prospectuses with the securities regulators. In addition, the Company maintains sufficient liquidity through committed credit facilities with its banking groups which would enable the Company to fund all anticipated requirements for one year without accessing the capital markets.

MARKET PRICE RISK

Enbridge's earnings are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively Market Price Risk). Given the Company's desire to maintain a stable and consistent earnings profile, it has implemented a Board of Directors approved Market Price Risk Policy to minimize the likelihood that adverse earnings fluctuations arising from movements in market prices across all of its businesses will exceed a defined tolerance. The Market Price Risk metric utilized within that policy is EaR, described above under Sensitivity Analysis.

The Company uses derivative financial instruments for market price risk management purposes. The following summarizes the types of market price risks to which the Company is exposed and the financial derivative hedging programs implemented.

Foreign Exchange Risk

The Company has exposure to foreign currency exchange rates, primarily arising from its U.S. dollar and euro denominated investments, where both carrying values and earnings are subject to foreign exchange rate vulnerability. Furthermore, the Company is exposed to foreign exchange rate variability on the conversion of the foreign currency denominated cash flows back to Canadian dollars (the "economic exposure"). The Company has a hedging policy to eliminate 50% to 70% of the long-term economic exposure related to its foreign currency denominated cash flows. It will also hedge shorter term anticipated foreign currency capital expenditures.

Interest Rate Risk

Enbridge is exposed to interest rate fluctuations on the cost of variable rate debt. Floating to fixed interest rate swaps, collars and forward rate agreements are used to hedge against the effect of future interest rate movements. The Company monitors its debt portfolio mix of fixed and variable rate debt instruments to ensure that the consolidated portfolio of debt stays within its Board of Directors approved policy limit band of up to 25% floating rate debt as a percentage of total debt outstanding. Fixed to floating swaps are also used from time to time to manage this position and optimize the Company's debt portfolio. The Company is also exposed to fluctuations in interest rates ahead of anticipated fixed rate debt issuances. The Company may enter into interest rate derivatives to hedge a portion of the interest cost of these future debt issues.

Information about the debt portfolio is included in Notes 12 and 13 of the Company's Consolidated Financial Statements for the year ended December 31, 2007.

Commodity Price Risk

The Company uses natural gas price swaps, futures and options to manage the value of commodity purchases and sales that arise from capacity commitments on the Alliance and Vector Pipelines. The Company also uses natural gas, power, crude oil and NGLs derivative instruments to fix the value of variable price exposures that arise from commodity usage, storage, transportation and supply agreements.

Fair Values of Derivative Instruments

Information about the financial instruments (including derivatives) outstanding at year end is included in Note 18 of the Company's Consolidated Financial Statements for the year ended December 31, 2007.

CREDIT RISK

Entering into derivative financial instruments can give rise to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. Overall credit exposure limits have been set in the Board of Directors approved Credit Policy.

The Company minimizes credit risk by entering into risk management transactions only with institutions that possess high investment grade credit ratings or have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty. For transactions with terms greater than five years, the Company may also require a counterparty that would otherwise meet the Company's credit criteria to provide collateral.

Credit risk also arises from trade receivables, which is mitigated by credit exposure limits, contractual and collateral requirements and netting arrangements. Credit risk in the Gas Distribution and Services segment is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process.

OPERATING RISKS

Pipeline Operating Risk

Pipeline leaks are an inherent risk of operations. Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the pipeline systems. The occurrence or continuance of any of these events could increase the cost of operating the Company's pipelines or reduce revenues, thereby impacting earnings.

The Company has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks.

Regulation

Many of the Company's pipeline operations are regulated and are subject to regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur. These changes may adversely affect toll structures or other aspects of pipeline operations or the operations of shippers.

Environmental, Health and Safety Risk

The Company's operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. Restrictions on other resources, such as water or electricity, may affect the Company's upstream customers' ability to produce. The Company could be targeted, along with the oil sands industry, by environmental groups to draw attention to greenhouse gas emissions.

Enbridge is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship. The Company believes that prevention of incidents and injuries, and protection of the environment benefits everyone and delivers increased value to shareholders, customers and employees. Enbridge has health and safety and environmental management systems and has established policies, programs and practices for conducting safe and environmentally sound operations. Regular reviews and audits are conducted to assess compliance with legislation and company policy.

CRITICAL ACCOUNTING ESTIMATES

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2007 of $12,597.6 million, or 63% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the

integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments, except the Corporate segment. For certain rate regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates. Revised assumptions have historically resulted in extending useful lives.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's Liquids Pipelines, Gas Pipelines and Gas Distribution and Services businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the ERCB and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the regulator. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. As of December 31, 2007, the Company's regulatory assets totaled $548.4 million (2006 – $559.7 million) and regulatory liabilities totaled $173.7 million (2006 – $146.6 million). To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and other post-employment benefits (OPEB) other than pensions to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. See Note 20 to the 2007 Annual Consolidated Financial Statements for disclosure of the difference between the actual and the expected results for the past two years. Pension expense is recorded within all of the Company's business segments.

(millions of dollars)	Pension Benefits		OPEB	
Impact of a 0.5% Change in Key Assumptions	Obligation	Expense	Obligation	Expense
Decrease in discount rate	78.3	10.2	14.8	1.3
Decrease in expected return on assets	n/a	5.7	n/a	0.2
Decrease in rate of salary increase	(19.2)	(4.3)	–	–

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and

certain of the Company's subsidiaries and investments including Enbridge Gas Distribution Inc. and Enbridge Energy Company, Inc. are disclosed in Note 24 of the 2007 Annual Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

The fair value of asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized as long-term liabilities in the period when they can be reasonably determined. The fair value approximates the cost a third party would charge in performing the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The present value of expected future cash flows is determined using assumptions such as the probability of abandonment in place versus removal and the estimated costs required upon abandonment in each case, the discount rate and the estimated time to abandonment. For the majority of the Company's assets it is not possible to make a reasonable estimate of AROs due to the indeterminate timing, the long-lived nature of the assets and the scope of the asset retirements. Changes in any of these assumptions could materially affect the asset and liability recognized in respect of asset retirement obligations as well as the resulting accretion of the liability and depreciation of the asset within any of the Company's business segments, with the exception of the Corporate segment.

CHANGE IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS, COMPREHENSIVE INCOME AND HEDGING RELATIONSHIPS

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 1530 *Comprehensive Income*, Section 3251 *Equity*, Section 3855 *Financial Instruments – Recognition and Measurement*, Section 3861 *Financial Instruments – Disclosure and Presentation* and Section 3865 *Hedges*. In accordance with the transitional provisions in these new standards, these policies were adopted prospectively and accordingly, the prior periods were not restated. Prior period unrealized gains and losses related to the Company's foreign currency translation adjustments and net investment hedges are now included in Accumulated Other Comprehensive Income or Loss.

The adoption of the new standards did not impact the Company's earnings or cash flows.

Financial Instruments

CICA Handbook Section 3855 establishes recognition and measurement criteria for financial instruments. The new standard requires that, generally, all financial instruments are recorded at fair value on initial recognition. Subsequent measurement depends on whether the instrument has been classified as "held to maturity", "held for trading", "available for sale" or "loans and receivables" as defined by Section 3855.

With the exception of recognizing derivative instruments, including hedge instruments, at fair value, the valuation of the Company's financial instruments has not changed. The methods by which the Company determines the fair value of its financial instruments have also not changed as a result of adopting this standard.

Impact on Adoption

The adoption of the new standards resulted in the following adjustments on January 1, 2007:

(millions of dollars) Increase/(Decrease)	Assets	Liabilities and Equity
Accounts Receivable and Other[1,2]	5.4	–
Deferred Amounts and Other Assets[1,2,3,4]	55.3	–
Long-Term Investments[1]	(57.3)	–
Accounts Payable and Other[2]	–	57.6
Long-Term Debt[3]	–	(52.7)
Other Long-Term Liabilities[1,2,4]	–	42.5
Future Income Taxes[1]	–	(18.9)
Non-Controlling Interest[1]	–	(26.3)
Accumulated Other Comprehensive Income[1]	–	48.2
Retained Earnings[1]	–	(47.0)
	3.4	3.4

1 *As a result of the new standards for cash flow hedges, the Company recognized unrealized net gains related to interest rate, foreign exchange and commodity hedges. The Company adjusted both deferred amounts and retained earnings for historical fair value adjustments related to certain cash flow hedges.*

2 *The Company recorded a regulatory liability due to the recognition of fixed price power contracts offset by unrealized financial instrument losses.*

3 *The Company reclassified unamortized deferred financing fees from deferred amounts and other assets to long-term debt as a result of adopting the new standards.*

4 *Relates to the recognition of gas purchase hedges for the regulated gas distribution businesses at January 1, 2007.*

FUTURE ACCOUNTING POLICY CHANGES

Capital Disclosures and Financial Instruments – Disclosure and Presentation

Effective January 1, 2008, the Company will adopt new accounting standards for Capital Disclosures (CICA Handbook Section 1535) and Financial Instruments – Disclosure and Presentation (CICA Handbook Sections 3862 and 3863).

Under Section 1535, the Company will disclose its objectives, policies and procedures for managing capital, any summary quantitative data about what the Company manages as capital, whether the Company has complied with any externally imposed capital requirements and, if the Company has not complied with them, any consequences of non-compliance with these capital requirements.

The new Sections 3862 and 3863 replace Section 3861 *Financial Instruments – Disclosure and Presentation*. Disclosure requirements are revised and enhanced, while presentation requirements remain essentially unchanged. The new disclosure requirements will expand discussion around the significance of financial instruments for the Company's financial position and performance, the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date and how the entity manages those risks.

Inventories

The CICA issued Section 3031 *Inventories* effective January 1, 2008 which aligns accounting for inventories under Canadian GAAP with International Financial Reporting Standards (IFRS). This standard will not materially impact the Company's financial statements.

Rate Regulated Operations

In August 2007, the Canadian Accounting Standards Board (AcSB) published its decision with respect to rate regulated operations. The AcSB decided to retain much of the existing guidance related to

rate-regulated operations; however, the exemption from the requirement to record future income taxes, as currently provided in CICA Handbook Section 3465, *Income Taxes*, and the exemption from CICA Handbook Section 1100, *Generally Accepted Accounting Principles,* will be removed, effective January 1, 2009. The Company will adopt these changes on January 1, 2009 and the principal effect will be the recognition of future income tax liabilities on the balance sheet, offset equally by regulatory assets.

International Financial Reporting Standards

In 2005, the AcSB announced that accounting standards in Canada are to converge with IFRS. Firms will begin reporting (with comparative data) under IFRS by the first quarter of 2011. While IFRS is based on a conceptual framework similar to Canadian GAAP, there are significant differences with respect to recognition, measurement and disclosures, which the Company is beginning to assess.

CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S securities law. As of the year ended December 31, 2007, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the Securities and Exchange Commission is recorded, processed, summarized and reported within the time periods required.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Enbridge Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rule of the United States Securities and Exchange Commission and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with GAAP.

The Company'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 Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles; and
- 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.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of 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 the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2007.

During the year ended December 31, 2007, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

QUARTERLY FINANCIAL INFORMATION[1]

(millions of dollars, except for per share amounts)

2007	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
Revenues	**3,358.2**	**2,728.7**	**2,634.0**	**3,198.5**	**11,919.4**
Earnings applicable to common shareholders	**227.0**	**146.5**	**78.1**	**248.6**	**700.2**
Earnings per common share	**0.65**	**0.41**	**0.22**	**0.70**	**1.97**
Diluted earnings per common share	**0.64**	**0.41**	**0.22**	**0.69**	**1.95**
Dividends per common share	**0.3075**	**0.3075**	**0.3075**	**0.3075**	**1.23**

(millions of dollars, except for per share amounts)

2006	Q1	Q2	Q3	Q4	Total
Revenues	3,346.7	2,327.2	2,184.9	2,785.7	10,644.5
Earnings applicable to common shareholders	190.9	157.9	95.5	171.1	615.4
Earnings per common share	0.56	0.47	0.28	0.50	1.81
Diluted earnings per common share	0.56	0.46	0.28	0.49	1.79
Dividends per common share	0.2875	0.2875	0.2875	0.2875	1.15

1 *Quarterly Financial Information has been extracted from financial statements prepared in accordance with generally accepted accounting principles.*

Revenue includes amounts billed to customers of EGD for natural gas, which varies with fluctuations in the commodity price. Higher natural gas commodity prices increase revenues, but would not similarly impact earnings, given the cost of natural gas flows through to customers. Fluctuations in commodity prices also impact revenues from Energy Services businesses.

In addition, revenue fluctuates due to the seasonality of EGD's business. Typically, revenue peaks in the winter months during the first quarter and, to a lesser extent, in the fourth quarter of the year when higher gas volumes are sold. Finally, 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:

- Fourth quarter earnings in 2007 included the impact of tax changes, which increased consolidated earnings.
- Third quarter 2007 included a loss from Aux Sable.
- Second quarter 2007 included higher earnings from EGD due to colder than normal weather and a dilution gain in EEP.
- First quarter 2007 included higher earnings from EGD due to colder weather than the prior year period and the receipt of 2005 hurricane insurance proceeds.

- Fourth quarter earnings in 2006 reflected higher earnings from the Enbridge System and Aux Sable, offset by lower earnings from EGD due primarily to warmer than normal weather and higher costs.
- Third quarter earnings in 2006 reflected higher earnings from Enbridge System, increased earnings from the Company's investment in EEP and the recognition of upside sharing in Aux Sable.
- Second quarter earnings in 2006 included the impact of tax rate reductions, which increased consolidated earnings.
- First quarter earnings in 2006 reflected increased earnings in Enbridge System more than offset by lower results from EGD, due primarily to warmer than normal weather.

FOURTH QUARTER 2007 HIGHLIGHTS

Earnings applicable to common shareholders were $248.6 million, of $0.70 per share, for the three months ended December 31, 2007, compared with $171.1 million, or $0.50 per share, for the three months ended December 31, 2006. Significant factors that increased earnings included strong fourth quarter results from Enbridge System and EGD as well as tax changes enacted in the fourth quarter of 2007.

SELECTED ANNUAL INFORMATION

(millions of dollars, except per share amounts)	**2007**	2006	2005
Total Revenues	**11,919.4**	10,644.5	8,453.1
Dividends per Common Share	**1.2300**	1.1500	1.0375
Common Share Dividends	**452.3**	403.1	361.1
Total Assets	**19,907.4**	18,379.3	17,210.9
Total Long-Term Liabilities	**11,117.4**	10,544.8	9,690.7

Total assets and long-term liabilities increased from 2006 to 2007 because of investments in organic growth projects. The increase in total assets and total long-term liabilities from 2005 to 2006 was also a result of ongoing investments in core businesses as well as a $280 million investment in EEP, increasing the Company's interest from 10.9% to 16.6%.

OUTSTANDING SHARE DATA

	Number
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares – issued and outstanding (voting equity shares)	368,690,996
Total issued and outstanding stock options (8,306,711 vested)	15,519,434

Outstanding share data information is provided as at February 20, 2008.

RELATED PARTY TRANSACTIONS

Information about the Company's related party transactions is included in Note 23 to the Company's consolidated financial statements for the year ended December 31, 2007.

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

Dated February 20, 2008

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Exhibit 99.6

CONSENT OF INDEPENDENT CHARTERED ACCOUNTANTS

We hereby consent to the inclusion in this Annual Report on Form 40-F and the incorporation by reference in the registration statements (Nos. 333-145236, 333-127265, 333-13456, 333-97305 and 333-6436) on Form S-8, (No. 33-77022) on Form F-3 and (No. 333-141478) on Form F-10 of Enbridge Inc. (the "Corporation") of our report dated February 20, 2008, relating to the consolidated financial statements of the Corporation as at December 31, 2006 and 2007 and for each of the years in the three year period ended December 31, 2007 and the effectiveness of internal control over financial reporting as at December 31, 2006 and 2007. Our report is included in Exhibit 99.4 to this Annual Report on Form 40-F.

"Signed"
PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta, Canada
February 20, 2008

QuickLinks

Exhibit 99.6

CONSENT OF INDEPENDENT CHARTERED ACCOUNTANTS