

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### CONSOLIDATED RESULTS

#### FINANCIAL PERFORMANCE<sup>1</sup>

<i>(millions of dollars, except per share amounts)</i>	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)
<b>Earnings Applicable to Common Shareholders</b>	<b>700.2</b>	615.4	556.0
<b>Earnings per Common Share</b>	<b>1.97</b>	1.81	1.65
<b>Diluted Earnings per Common Share</b>	<b>1.95</b>	1.79	1.63

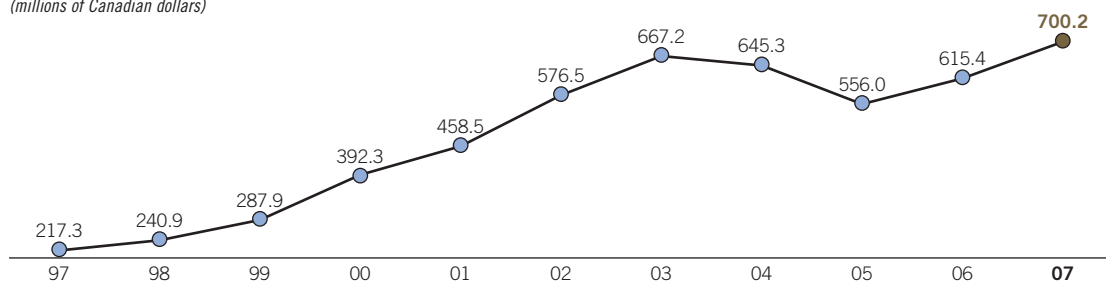
<sup>1</sup> Financial Performance data have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

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.*

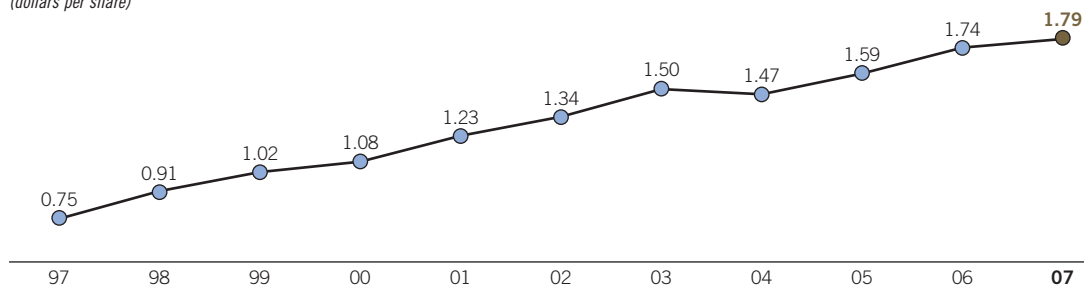
## NON-GAAP MEASURES

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**

<i>(millions of dollars, except per share amounts)</i>	2007	2006	2005
GAAP earnings as reported	<b>700.2</b>	615.4	556.0
Significant after-tax non-operating factors and variances:			
Liquids Pipelines			
Impact of tax changes	<b>(1.2)</b>	–	–
Gas Pipelines			
Offshore property insurance recovery from 2005 hurricanes	<b>(5.3)</b>	–	–
Sponsored Investments			
Dilution gains on EEP Class A unit issuance	<b>(11.8)</b>	–	(8.9)
EEP unrealized derivative fair value losses/(gains)	<b>6.3</b>	(6.5)	5.0
EEP gain on sale of assets of Kansas Pipeline Company	<b>(3.0)</b>	–	–
Impact of tax changes	<b>(1.9)</b>	(6.0)	–
Gas Distribution and Services			
Warmer/(colder) than normal weather affecting EGD	<b>(14.2)</b>	36.9	–
Energy Services unrealized derivative fair value losses	<b>2.4</b>	–	–
Aux Sable unrealized derivative fair value losses	<b>28.1</b>	–	–
Dilution gain in Noverco (Gaz Metro unit issuance)	–	(4.0)	(7.3)
Impact of tax changes	<b>(27.7)</b>	(28.9)	–
International			
Gain on land sale in CLH	<b>(5.2)</b>	–	(7.6)
Corporate			
Impact of tax changes	<b>(30.2)</b>	(14.0)	–
<b>Adjusted Operating Earnings</b>	<b>636.5</b>	592.9	537.2
<b>Adjusted Operating Earnings per Common Share</b>	<b>1.79</b>	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<sub>2</sub> 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.

<i>(in billions of Canadian dollars)</i> Commercially Secured Projects <sup>1</sup>	Estimated Capital Cost <sup>2</sup>	Expenditures to Date	Expected In-Service Date	Status
<b>Liquids Pipelines</b>				
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 <sup>3</sup>	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
<b>Sponsored Investments (EEP)</b>				
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 <sup>3</sup>	No significant expenditures to date	Mid-2010	Awaiting regulatory approval
<b>Total</b>	<b>\$12.4 billion</b>			
<b>Gas Distribution and Services</b>				
15. Ontario Wind Project	\$0.5 billion	\$0.3 billion	Late 2008	Under construction
<b>Projects Under Development<sup>1</sup></b>				
		Potential In-Service Date	Status	
<b>Liquids Pipelines</b>				
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	
<b>Sponsored Investments (EEP)</b>				
22. Various Liquids Pipelines Mainline Expansions		2010 - 2015	In planning stage	
<b>Gas Distribution and Services</b>				
23. Rabaska LNG Facility		2011 - 2012	In commercial discussions	

<sup>1</sup> Descriptions of each project are included in the strategy section for each business segment.

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

<sup>3</sup> 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.



**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

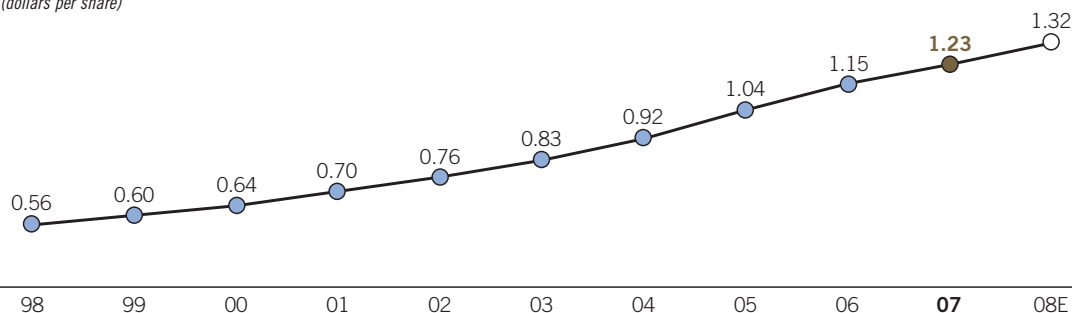
At Enbridge, being socially responsible means doing things right, and doing the right thing. Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical way; protecting the environment and the health and safety of people; supporting human rights;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

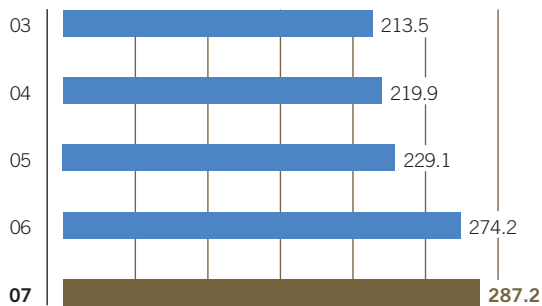
<i>(millions of dollars)</i>	2007	2006	2005
Enbridge System	202.5	202.3	170.1
Athabasca System	53.7	52.8	48.6
Olympic Pipeline	9.9	6.5	–
Spearhead Pipeline	10.0	6.3	(1.1)
Southern Lights Pipeline	6.8	–	–
Feeder Pipelines and Other	3.1	6.3	11.5
Impact of tax changes	1.2	–	–
	<b>287.2</b>	274.2	229.1

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. Toll rates 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<sup>1</sup> 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<sup>2</sup> and remaining established reserves from oil sands were estimated at 173 billion barrels<sup>3</sup>. Combined conventional and oil sands reserves put Canada second only to Saudi Arabia with 13.4% of the worldwide estimated proved reserves<sup>4</sup>. In addition, the vast Canadian oil sands resource is geopolitically secure and in close proximity to U.S. markets.

## 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.<sup>5</sup> 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<sup>6,7</sup>. 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<sup>6</sup>. During 2007, greater volumes of Western Canadian crude oil were transported to Ontario<sup>7</sup>, displacing Atlantic Basin crude oil<sup>6</sup>.

## 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

<sup>1</sup> National Energy Board 2007 Estimated Production of Canadian Crude Oil and Equivalent Table 1

<sup>2</sup> Canadian Association of Petroleum Producers Statistical Handbook 2007

<sup>3</sup> Alberta Energy and Utilities Board Alberta's Reserves 2006 and Supply/Demand Outlook/Overview

<sup>4</sup> Oil and Gas Journal's Worldwide Look at Reserves and Production, December 24, 2007

<sup>5</sup> "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

<sup>6</sup> "Disposition of Domestic Light and Heavy Crude Oil and Imports – 2007 & 2005", National Energy Board

<sup>7</sup> "2007 & 2005 Estimated Production of Canadian Crude Oil and Equivalent", National Energy Board

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 throughput 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).

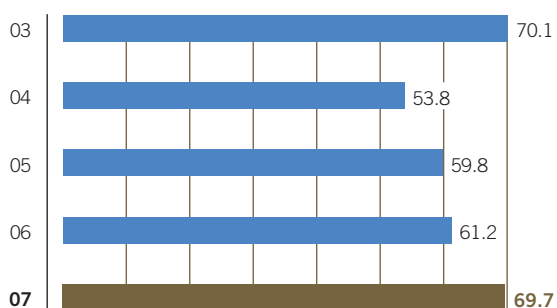
### Earnings

<i>(millions of dollars)</i>	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
	<b>69.7</b>	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 Pipeline's 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

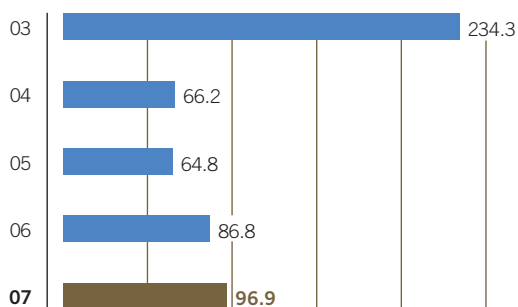
The Company expects to spend approximately \$49 million in 2008 in the Gas Pipelines segment for ongoing capital improvements, core maintenance capital projects and expansion, including the projects described above. In 2007, the Company spent \$200 million on capital expenditures in the Gas Pipelines 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

<i>(millions of dollars)</i>	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	–
	<b>96.9</b>	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*

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 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

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.

### 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

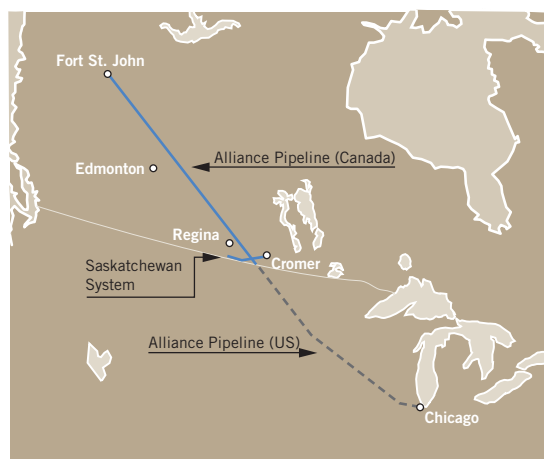
EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the 100%-owned Enbridge Saskatchewan System, both acquired from the Company in 2003. Alliance Pipeline Canada is the Canadian portion of the Alliance System described in the Gas Pipelines segment above. The Enbridge Saskatchewan 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.



*Enbridge Income Fund*

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

<i>(millions of dollars)</i>	2007	2006	2005
Enbridge Gas Distribution	<b>128.8</b>	61.8	111.9
Noverco	<b>18.6</b>	22.7	28.3
Enbridge Gas New Brunswick	<b>12.1</b>	9.8	6.1
Other Gas Distribution	<b>7.3</b>	6.5	6.7
Energy Services <sup>1</sup>	<b>3.6</b>	10.1	5.0
Aux Sable	<b>(17.5)</b>	25.8	5.3
Other <sup>1</sup>	<b>3.5</b>	12.6	15.5
Impact of tax changes	<b>27.7</b>	28.9	–
	<b>184.1</b>	178.2	178.8

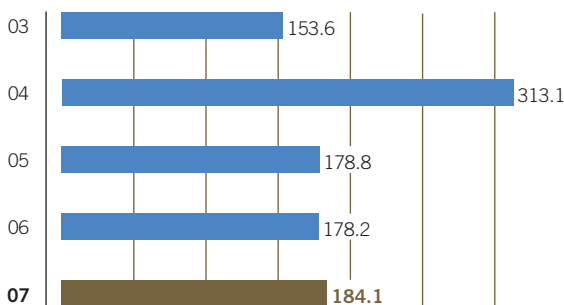
<sup>1</sup> Tidal Energy's results have been reclassified from Other to Energy Services for all periods presented. Other now includes earnings from CustomerWorks.

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.

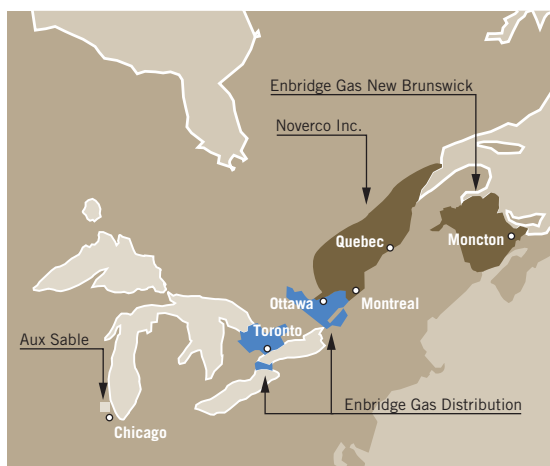


### Gas Distribution and Services

#### 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 ( <i>millions of Canadian dollars</i> )	\$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

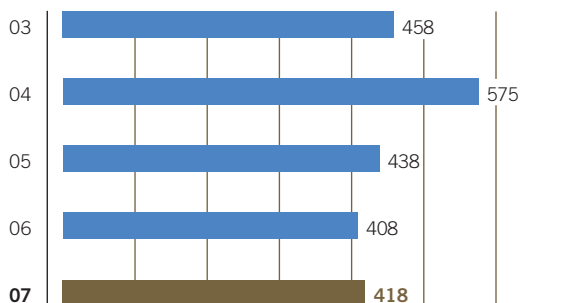
In February 2007, an explosion and fire occurred at a residence on Harper Gardens in Toronto. The home was destroyed and a resident of the home was killed. A gas fitter in the home at the time of the explosion was seriously burned. Several public authorities are investigating the incident. EGD has also 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 sour 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 Compañía 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

<i>(millions of dollars)</i>	2007	2006	2005
CLH	<b>65.6</b>	54.5	61.6
OCENSA/CITCol	<b>32.9</b>	33.9	32.8
Other	<b>(3.4)</b>	(5.2)	(7.0)
	<b>95.1</b>	83.2	87.4

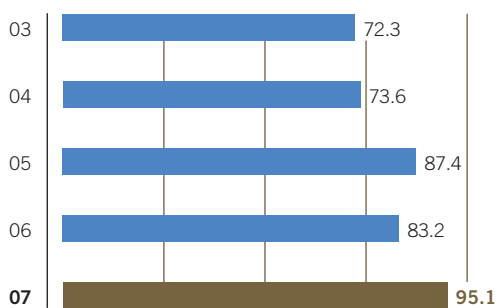
Earnings for the year ended December 31, 2007 were \$95.1 million compared to \$83.2 million for the year ended December 31, 2006. Earnings in 2007 included a \$5.2 million gain on the sale of land within CLH. The increase in earnings was also due to stronger operating earnings in CLH as a result of 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

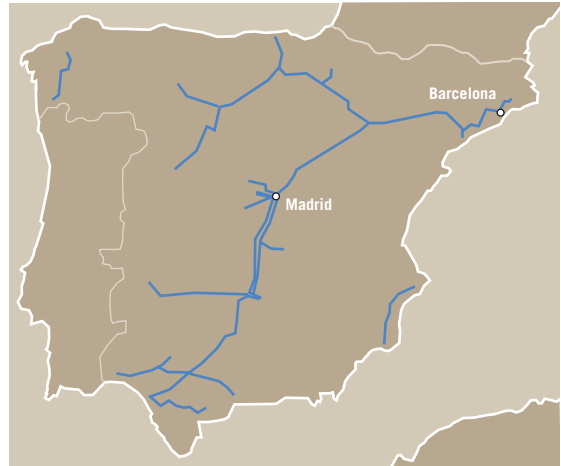


### International Earnings

*(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/CITCoI**

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, CITCoI, 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

<i>(millions of dollars)</i>	2007	2006	2005
Corporate	<b>(63.0)</b>	(82.2)	(63.9)
Impact of tax changes	<b>30.2</b>	14.0	–
	<b>(32.8)</b>	(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.

<i>(millions of dollars)</i>	2007	2006	2005
Earnings net of non-cash items	<b>1,358.0</b>	1,171.0	1,300.9
Changes in operating assets and liabilities	<b>20.7</b>	126.7	(353.9)
Cash Provided by Operating Activities	<b>1,378.7</b>	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.

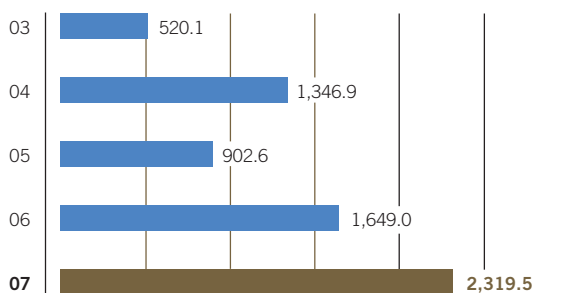
Dividends on common shares increased again in 2007 due to an increased number of common shares outstanding and a higher dividend rate.

### 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:

<i>(millions of dollars)</i>	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt <sup>1</sup>	8,318.3	604.5	1,054.3	400.0	6,259.5
Non-recourse long-term debt <sup>1</sup>	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 <sup>2,3</sup>	2,505.8	935.9	900.4	381.9	287.6
<b>Total Contractual Obligations</b>	<b>12,515.0</b>	<b>1,612.0</b>	<b>2,321.9</b>	<b>991.9</b>	<b>7,589.2</b>

<sup>1</sup> Excludes interest component.

<sup>2</sup> Approximately \$947.6 million of these contracts are commitments for materials related to the construction of Liquids Pipelines projects.

<sup>3</sup> 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.

<i>(millions of dollars)</i>	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
Impact of a 0.5% Change in Key Assumptions				
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 <sup>1,2</sup>	5.4	–
Deferred Amounts and Other Assets <sup>1,2,3,4</sup>	55.3	–
Long-Term Investments <sup>1</sup>	(57.3)	–
Accounts Payable and Other <sup>2</sup>	–	57.6
Long-Term Debt <sup>3</sup>	–	(52.7)
Other Long-Term Liabilities <sup>1,2,4</sup>	–	42.5
Future Income Taxes <sup>1</sup>	–	(18.9)
Non-Controlling Interest <sup>1</sup>	–	(26.3)
Accumulated Other Comprehensive Income <sup>1</sup>	–	48.2
Retained Earnings <sup>1</sup>	–	(47.0)
	3.4	3.4

<sup>1</sup> 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.

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

<sup>3</sup> 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.

<sup>4</sup> 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<sup>1</sup>

(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

<sup>1</sup> 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

<i>(millions of dollars, except per share amounts)</i>	2007	2006	2005
Total Revenues	<b>11,919.4</b>	10,644.5	8,453.1
Dividends per Common Share	<b>1.2300</b>	1.1500	1.0375
Common Share Dividends	<b>452.3</b>	403.1	361.1
Total Assets	<b>19,907.4</b>	18,379.3	17,210.9
Total Long-Term Liabilities	<b>11,117.4</b>	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](http://www.sedar.com).

Dated February 20, 2008