

Management's Discussion and Analysis Enbridge Inc.

CONSOLIDATED RESULTS

FINANCIAL PERFORMANCE¹

<i>(millions of Canadian dollars, except per share amounts)</i>	2006	2005	2004
Liquids Pipelines	274.2	229.1	219.9
Gas Pipelines	61.2	59.8	53.8
Sponsored Investments	86.8	64.8	66.2
Gas Distribution and Services ²	178.2	178.8	313.1
International	83.2	87.4	73.6
Corporate	(68.2)	(63.9)	(81.3)
Earnings Applicable to Common Shareholders	615.4	556.0	645.3
Earnings Per Common Share	1.81	1.65	1.93
Diluted Earnings Per Common Share	1.79	1.63	1.91

1. Financial Performance data have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.
2. The reported results for the year ended December 31, 2004 include earnings for the 15 months ended December 31, 2004 for Enbridge Gas Distribution (EGD), Noverco and other gas distribution entities. This inclusion resulted from the elimination of the quarter lag basis of consolidation in 2004.

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 Enbridge Energy Partners, LP (EEP) and from the Aux Sable natural gas fractionation facility. 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 Enbridge Gas Distribution (EGD), as the weather in the Ontario market was significantly warmer than normal during 2006.

Earnings applicable to common shareholders were \$556.0 million for the year ended December 31, 2005, or \$1.65 per share, compared with \$645.3 million, or \$1.93 per share, in 2004. The \$89.3 million decrease in earnings was primarily the result of the sale of the investment in AltaGas in 2004, which resulted in an after-tax gain of \$97.8 million as well as the absence of earnings from AltaGas after the sale. Earnings for 2004 also included 15 months of earnings for gas distribution utilities, reflecting the change in year end for those entities. Positive factors in 2005 included the earnings contribution from the Enbridge Offshore Pipelines, higher contribution from the gas distribution utility and lower interest expense.

FORWARD LOOKING INFORMATION

In the interest of providing Enbridge shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of Enbridge's and its subsidiaries' future plans and operations, certain information provided in this Management's Discussion and Analysis (MD&A) constitutes forward-looking statements or information (collectively, "forward-looking statements"). 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, 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.

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 – Adjusted Operating Earnings

Management believes that the presentation of adjusted operating earnings provides useful information to investors and shareholders as it provides increased predictive value and performance trends. Adjusted operating earnings represent earnings applicable to common shareholders adjusted for significant non-operating factors. This measure does not have a standardized meaning prescribed by Canadian generally accepted accounting principles (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 Canadian dollars, except per share amounts)</i>	2006	2005	2004
GAAP earnings as reported	615.4	556.0	645.3
Significant after-tax non-operating factors and variances:			
Sponsored Investments			
Dilution gains on the issue of EEP units	-	(8.9)	(7.6)
EEP non-cash derivative fair value losses/(gains)	(6.5)	5.0	-
Revalue future income taxes due to tax rate changes	(6.0)	-	-
Gas Distribution and Services			
Gain on sale of investment in AltaGas Income Trust	-	-	(97.8)
EGD calendar year basis adjustment ¹	-	-	(27.1)
Warmer/(colder) than normal weather	36.9	-	(21.3)
Impairment loss on Calmar gas plant	-	-	8.2
Dilution gain in Noverco (Gaz Metro unit issuance)	(4.0)	(7.3)	-
Dilution gain – AltaGas Income Trust	-	-	(8.0)
Revalue future income taxes due to tax rate changes	(28.9)	-	(0.6)
International			
Gain on land sale in CLH	-	(7.6)	-
Corporate			
Revalue future income taxes due to tax rate changes	(14.0)	-	-
Adjusted Operating Earnings	592.9	537.2	491.1
Adjusted Operating Earnings per Common Share	1.74	1.59	1.47

1. Effective December 31, 2004, EGD changed its fiscal year-end from September 30 to December 31. Consequently, the reported consolidated results for the year ended December 31, 2004 included EGD's results for the fifteen months ended December 31, 2004. The adjustment above deducts EGD's results for the three months ended December 31, 2003, to reflect EGD's 2004 earnings on the calendar basis, consistent with 2005 and 2006.

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

Significant operating factors affecting earnings in 2006 include:

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

Enbridge advanced several strategic initiatives during 2006:

- Commenced construction of the Southern Access Expansion;
- Completed the reversal of Spearhead Pipeline, which commenced operations in the first quarter of 2006;
- Received industry support for the Alberta Clipper Project;
- Received industry support for the Southern Lights Pipeline project; and
- Announced plans to construct a natural gas lateral to connect the deepwater Shenzi field to existing Gulf of Mexico pipelines.

C O R P O R A T E S T R A T E G Y

Corporate Vision and Key Objective

Enbridge is an energy delivery company that transports natural gas and crude oil, which are used 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 key elements of this vision are to:

- focus on operational excellence, customers and communities;
- generate above industry-average annual earnings per share growth;
- maintain a strong risk-reward investment profile and financial position;
- deliver superior dividend growth and capital appreciation to shareholders; and
- position the Company for the energy environment of the future.

Competitive Advantage

The Company's ability to execute its strategy and realize its corporate vision depends on three key strengths, among others. These include the strategic position of the Company's major assets, the diversification of the business and the Company's 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 oil sands reserves in Western Canada. Enbridge's existing right of way is valuable in developing major expansion projects due to the substantial capacity of its mainline system. Enbridge has economies of scale because of its multiple separate lines and has flexibility in terms of the types of products moved. Enbridge moves over 60 different grades of crude oil. Also, the Company serves a diversity of markets because of the extent and reach of its pipeline systems.

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 the business.

The Company is focused on adding value for customers and improving customers' pricing. This focus has aligned the Company with supply-demand fundamentals, which has consistently formed a basis for the Company's strategy. Two of the ways that the Company seeks to provide value to customers are through providing customers with access to diverse markets and optionality with respect to the timing of project development. The Company has a number of organic growth projects designed to enable customers to reach new markets.

Organic Growth Projects

The thrust of the Company's strategy is growth through internally developed organic projects. The Company is advancing the development of a number of organic growth projects, some of which are summarized below and would support annual organic growth rates averaging 6% to 9% over the next five years. Enbridge will continue to pursue acquisitions that are accretive to earnings, on an opportunistic basis, as a supplementary source of growth.

Project	Estimated Capital Cost (Canadian dollars unless otherwise noted)	Expected Date of Completion
<u>Liquids Pipelines</u>		
Southern Access – Canadian portion	\$0.2 billion	2006 – 2009, in stages
Alberta Clipper – Canadian portion	\$1.5 billion (2006 dollars)	Late 2009 or 2010
Spearhead Pipeline Expansion	\$0.1 billion	2009
Line 4 Extension	\$0.3 billion	Late 2008
Waupisoo Oil Pipeline	\$0.5 billion	Mid 2008
Athabasca Pipeline Expansions and Laterals	\$0.2 billion	Early 2007
New Upstream Pipeline Opportunities	See project description	2010 – 2012
Southern Access Extension	US\$0.4 billion	2009
U.S. Gulf Coast Initiatives	See project description	2010 – 2011
Eastern PADD II/Canada Initiatives	See project description	2010 – 2011
Gateway Condensate Import	See project description	2012 – 2014
Gateway Petroleum Export	See project description	2012 – 2014
Southern Lights Pipeline	US\$1.3 billion	Mid 2010
Upstream Contract Terminaling	\$0.6 billion	2007 – 2009
Downstream Contract Terminaling	US\$0.2 billion	2007 – 2008
Common Carrier Terminaling	\$0.1 billion	2008
<u>Sponsored Investments (EEP)</u>		
Project Clarity – East Texas	US\$0.6 billion	2007 in stages
Various Gas Plants – Texas	US\$0.1 billion	2007 – 2008
Southern Access – U.S. portion	US\$1.3 billion	2008 – 2009 in stages
Alberta Clipper – U.S. portion	US\$0.8 billion	2010
Downstream Contract Terminaling	US\$0.1 billion	2007 – 2008
Common Carrier Terminaling	US\$0.1 billion	2008
<u>Gas Pipelines</u>		
Neptune Offshore Laterals	US\$0.1 billion	End of 2007
Vector Pipeline Expansion	US\$0.1 billion	Late 2007
<u>Gas Distribution and Services</u>		
EGD Customer Additions & System Integrity	\$1.5 billion	2007 – 2011
Ontario Wind Project	\$0.5 billion	Late 2008
Rabaska LNG Facility	\$0.3 billion by Enbridge	2010 - 2011

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

Descriptions of each project are included in the strategy section of each core business.

Strategy

Enbridge has four key strategies to generate superior shareholder value.

1. Expand Existing Core Businesses

The Company will expand its core asset platforms and existing businesses. Strategies for each core business are included in the sections below. The primary goal of this strategy will be organic growth initiatives that leverage advantages from existing assets and expand service into new markets.

2. Focus on Operational Excellence and People

Enbridge will continue its focus on operational excellence, including cost efficiency, safety and reliability, customer relationships, protection of the environmental, innovation and effective stakeholder relations. Enbridge will also focus on managing human capital constraints resulting from the opportunities and growth in the energy industry.

3. Capitalize on the Partnership/Trust Model

Enbridge owns investments in and manages Enbridge Income Fund (EIF) and EEP, which will develop or acquire energy infrastructure assets in North America and optimize the returns on assets they currently own.

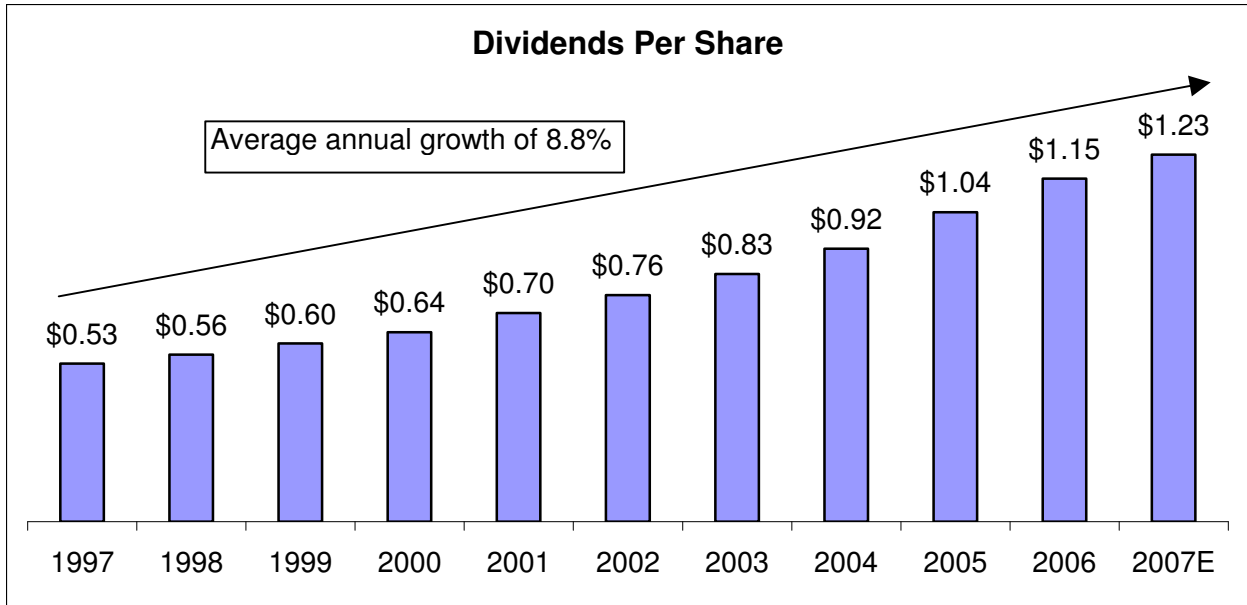
4. Develop New Growth Platforms

Enbridge believes it is also important to develop new growth platforms that complement the existing core asset base. Initiatives include liquefied natural gas (LNG) regasification, power generation 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".

Dividends

The Company's dividend payout ratio reflects a strong and stable long-term outlook for the business. 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. The following chart shows dividends per share for the last 10 years and estimated dividends for 2007, based on the quarterly dividend of \$0.3075 per common share declared by the Board of Directors on January 16, 2007.



Corporate Social Responsibility

Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical way, protecting the environment and 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 Sarbanes-Oxley requirements and the Canadian equivalent rules, internal and external audits of operations throughout the Company, employee compliance with Enbridge's Statement of Business Conduct and a majority of independent Directors on the Company's Board as well as plain and open communication with stakeholders.

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

Stakeholder relations involve developing positive relationships with government agencies, environmental groups, landowners, business partners and local communities. 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 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.

Enbridge makes voluntary contributions to charitable organizations in the areas of: education, health, environment, social services, arts and culture, civic leadership and volunteer resources 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 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 Enbridge Gas Distribution (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 and refined products pipelines in Canada and the United States.

Earnings

<i>(millions of Canadian dollars)</i>	2006	2005	2004
Enbridge System	202.3	170.1	171.6
Athabasca System	52.8	48.6	42.8
Spearhead Pipeline	6.3	(1.1)	(0.4)
Olympic Pipeline	6.5	-	-
Feeder Pipelines and Other	6.3	11.5	5.9
	274.2	229.1	219.9

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.

Earnings from Liquids Pipelines were \$229.1 million for the year ended December 31, 2005, an increase of \$9.2 million from 2004. The increase was due to higher Athabasca System

earnings, consistent with the take or pay agreement with the major shipper, and improved earnings from Feeder Pipelines and Other, primarily Frontier Pipeline, which paid Federal Energy Regulatory Commission (FERC) ordered reparations in 2004.

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.

Revenues in the Liquids Pipelines segment were \$881.0 million in 2005 comparable with \$872.7 million for 2004.

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). Through five adjacent pipelines, the system transports crude oil from Western Canada to the Midwest region of the United States and Eastern Canada and serves all of the major refining centers in Ontario. Enbridge has operated, and frequently expanded, the mainline system since 1949.

Results of Operations

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 higher earnings from 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.

Enbridge System earnings were \$170.1 million for the year ended December 31, 2005 compared with \$171.6 million for the year ended December 31, 2004. The \$1.5 million decrease was due to a lower earnings base from the ITS component of Enbridge System and higher taxes within the Terrace component. The decrease was partially offset with earnings from the reliability and service metrics under the ITS as well as savings from cost management programs.

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 System Expansion Program (SEP) II Risk Sharing Agreement. Tolls on the core mainline system have been governed by incentive tolling settlements since 1995.

In 2005, Enbridge and the Canadian Association of Petroleum Producers (CAPP) approved the key terms of a new negotiated ITS, effective from January 1, 2005 to December 31, 2009. In January 2006, the NEB approved the ITS. The ITS continues the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In addition to the incentive-based provisions in prior agreements, service and reliability metrics have been added to the new ITS to further align the Company's interests with its shippers. The Company

has the opportunity to increase earnings by achieving performance targets under the new performance metric provisions.

In conjunction with the Terrace Agreement, the new 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 collect its annual revenue requirement, such deficiency is rolled into the subsequent year's tolls for collection from toll payers at that time and a receivable is recognized. This basis may affect the timing of recognition of revenues compared with that otherwise expected under generally accepted accounting principles for companies that are not rate-regulated.

Athabasca System

The Athabasca System, a 540-kilometre (340-mile) synthetic and heavy oil pipeline, links the Athabasca oil sands in the Fort McMurray, Alberta region, to a pipeline transportation hub at Hardisty, Alberta. The Athabasca System also includes the MacKay River, Christina Lake, Surmont and Long Lake feeder lines, growing tankage facilities and the Company's interest in the Hardisty Caverns Limited Partnership, which provides crude oil storage services.

Results of Operations

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.

Athabasca System earnings were \$48.6 million for the year ended December 31, 2005, an increase of \$5.8 million from 2004. The increase was consistent with the long-term contract with its major shipper as well as lower operating costs due to leak remediation costs in 2004.

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.

Spearhead Pipeline

The Spearhead Pipeline commenced delivery of crude oil from Chicago, Illinois to Cushing, Oklahoma in March 2006. The performance of the Spearhead Pipeline has continued to surpass Enbridge's expectations with fourth quarter nominations exceeding the pipeline's 125,000 barrels per day (bpd) capacity. Enbridge is currently evaluating the potential to expand the Spearhead pipeline.

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 480 kilometers (300 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland. The system consists of 640 kilometers (400 miles) of 6 to 20 inch diameter pipe, a 500,000-barrel terminal, 9 pumping stations and 21 delivery facilities. BP is the operator of the pipeline.

Olympic Pipeline has performed reliably and 2006 earnings were in line with expectations.

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 (Frontier, Toledo, Mustang and Chicap), liquid storage facilities (Patoka) and business development costs related to Liquids Pipelines activities.

Earnings in Feeder Pipelines and Other were \$6.3 million for the year ended December 31, 2006 compared with \$11.5 million for the year ended December 31, 2005 primarily due to increased business development costs related to the Company's organic growth projects.

Feeder Pipelines and Other earnings for the year ended December 31, 2005 were \$11.5 million compared with \$5.9 million for the year ended December 31, 2004. The increase was due to the capitalization of Gateway condensate pipeline costs in 2005, as the criteria for capitalization were met, starting in 2005. In addition, Frontier Pipeline earnings were higher due to lower operating costs as well as FERC ordered reparations paid in 2004.

Strategy

The Company seeks to go beyond the traditional regulated utility business model to create additional value for customers. The Liquids Pipelines strategy focuses on meeting the needs of Western Canadian producers and is supported by the Company's estimates of supply and demand for Western Canadian crude oil.

Supply and Reserves

The vast resource of the Western Canadian Sedimentary Basin (WCSB) and its development, create the basis for the Liquids Pipelines growth strategy. Generally, development of the oil sands resource has more than offset declining conventional production. The NEB estimates that total Western Canada production will be 2.5 million bpd¹ at the end of 2006 (2005 – 2.3 million bpd). At the end of 2005, remaining established conventional oil reserves in Western Canada were estimated to be 3.8 billion barrels² and remaining established reserves from oil sands were estimated at 174 billion barrels³. Combined conventional and oil sands reserves put Canada second only to Saudi Arabia with 14% of the worldwide estimated proved reserves⁴.

(1) National Energy Board 2006 Estimated Production of Canadian Crude Oil and Equivalent Table 1

(2) Canadian Association of Petroleum Producers Statistical Handbook 2006

(3) Alberta Energy and Utilities Board Alberta's Reserves 2005 and Supply/Demand Outlook/Overview

(4) Oil and Gas Journal's Worldwide Look at Reserves and Production, December 18, 2006

Demand for WCSB Crude

The Company's liquids pipelines are dependent upon the demand for crude oil and other liquid hydrocarbons produced from 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, principally to refineries, either directly or through the connecting pipelines of other companies. Within these regions are located major refining centres 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, 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.

Historically, Canada has been the third largest supplier of crude to the U.S. However, for the past three years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S.¹

Deliveries of WCSB crude into PADD II increased by 64,300 bpd over the last two years with increased WCSB crude oil supply in 2006². Over the same two-year period, deliveries into PADD IV (the U.S. Rocky Mountains) have increased by 6,700 bpd, PADD V (the Western U.S.) deliveries have increased by 6,000 bpd, and PADD III deliveries have increased by 63,800 bpd². Western Canadian demand is served by local supply and has remained relatively flat over the last two years². During 2006, greater volumes of Western Canadian crude were transported to Ontario³, pushing back Atlantic Basin crude oil².

- (1) "Table 38: Year-To-Date Imports of Crude Oil and Petroleum Products into the United States by Country of Origin, January – October 2006", Energy Information Administration/Petroleum Supply Monthly, December 2006
- (2) "Disposition of Domestic Light and Heavy Crude Oil and Imports – 2006", National Energy Board
- (3) "2006 Estimated Production of Canadian Crude Oil and Equivalent", National Energy Board

Key Components of the Liquids Pipelines Strategy

The Liquids Pipelines strategy is driven by the industry's need for export capacity alternatives, economic sources of diluent and U.S. refiners' need to maintain diversified sources of supply. The six 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. Capitalize on the Mainline ITS

The ITS rewards Enbridge for achieving certain targeted service levels and product attributes, which adds value for customers. To ensure returns on mainline operations are maximized, the Company will focus on cost efficiency, providing reliable capacity and predictable deliveries, and maintaining optimal batch quality.

The ITS service metrics establish financial bonuses and penalties for prescribed performance targets related to crude oil quality management and predictability of scheduled deliveries. The potential bonuses and penalties for the service metrics are limited to a maximum of \$10 million after tax in 2005, escalating to \$15 million in each of 2006 and 2007, and to \$20 million in each of 2008 and 2009. The targets to achieve the maximum bonus under the ITS become increasingly difficult to achieve in successive years.

The reliability metric provides for bonuses and penalties associated with optimization of system capacity, which are calculated monthly relative to annual capacity targets. Practical constraints around pipeline capacity would limit the bonus for the reliability metric to approximately \$12 million per year and penalties are limited to \$10 million per year.

Enbridge achieved total metrics bonuses of approximately \$10 million in 2006.

2. Mainline Capacity Expansion

The Chicago refining market has been a traditional destination for Western Canadian crude. The Company is working with shippers and refiners to further expand this market. The Southern Access Expansion and the Alberta Clipper Project are two projects that the Company is undertaking to meet this objective.

Southern Access Mainline Expansion

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.

The Canadian segment expansion schedule has been expedited with 120,000 bpd added in 2006, an additional 63,000 bpd expected in 2008 and another 85,000 bpd expected in 2009 in order to match the total additional capacity of 400,000 bpd being provided in the United States. With the support of industry, the proposed diameter of the Southern Access Expansion from Superior, Wisconsin to Flanagan, Illinois has been increased to 42 inches, increasing the estimated cost to US\$1.3 billion on the U.S. segment, to be undertaken by EEP. The estimated cost of the Canadian segment, to be undertaken by Enbridge is \$0.2 billion.

The FERC has approved an Offer of Settlement with respect to rates for the U.S. segment of the expansion. Enbridge filed a Southern Access Expansion surcharge methodology with the NEB in June 2006.

Alberta Clipper Project

The Alberta Clipper Project involves the construction of a new 36-inch diameter pipeline from Hardisty, Alberta to Superior, Wisconsin, in conjunction with additional pumping power applied to the new 42-inch pipe from Superior to Flanagan, Illinois, described above under Southern Access Expansion. The 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.

The expected capacity of the pipeline has been increased from 400,000 bpd to 450,000 bpd. The Canadian segment of the line is expected to cost \$1.5 billion (in 2006 dollars) and the U.S. segment, which will be undertaken by EEP, is expected to cost US\$0.8 billion.

In January 2007, industry confirmed its support for the Alberta Clipper Project. Regulatory applications will be filed once commercial terms are finalized, which is expected to occur in the first quarter of 2007. The Alberta Clipper Project is expected to be in service in late 2009 or 2010.

Line 4 Extension Project

The Company obtained industry support for the extension of Line 4, part of the Enbridge mainline system, between Hardisty, Alberta and the Company's terminal at Edmonton, Alberta. The project is expected to cost \$0.3 billion and, subject to receipt of required regulatory approvals, is targeted to be in service in late 2008.

3. Upstream Pipeline Development

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 expansion of the Athabasca System, including the construction of Long Lake and Surmont laterals. In addition, a number of large new oil sands projects requiring substantial upstream pipeline facilities will be selecting a service provider in 2007, and the Company is well positioned to secure a significant portion of these growth opportunities.

Waupisoo Pipeline

The 30-inch diameter, 380-kilometer (236-mile) long Waupisoo Pipeline will transport crude oil from the Cheecham terminal, currently under construction on the Athabasca Pipeline, to the Edmonton, Alberta area. 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.

Enbridge has filed an application for regulatory approval with the Alberta Energy and Utilities Board and other provincial government departments. Subject to timely receipt of regulatory approvals, expected in the first quarter of 2007, Enbridge will begin construction on the approximately \$0.5 billion pipeline in 2007, with an expected in-service date of mid-2008.

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

Athabasca Pipeline Expansion Projects

In 2006, the Company furthered several expansion projects on the Athabasca Pipeline. The expansion projects include the addition of pumping stations at Elk Point and Cheecham, as well as modifications to existing pumping stations. Construction is progressing and the projects are scheduled to be completed early 2007.

Surmont Oil Sands Project

The Surmont Oil Sands Project consists of pipeline and tank facilities required by the Surmont Project at the Cheecham Terminal on the Athabasca Pipeline. Enbridge has 25-year agreements with ConocoPhillips Surmont Partnership and Total E&P Canada Ltd. (the Surmont Shippers), to provide pipeline transportation services on the Athabasca Pipeline for an initial contract volume of up to 50,000 bpd of crude oil with the option to increase the contract volume to up to 220,000 bpd for future phases of production. The agreements also provide flexibility for the Surmont Shippers to transfer their production to the proposed Waupisoo Pipeline to the Edmonton area. Enbridge has completed construction and is awaiting first production.

Long Lake Oil Sands Project

The Company has agreements with Nexen Inc. and OPTI Canada Inc. (the Long Lake Shippers) to provide pipeline transportation services for the Long Lake Project. The agreements provide for an initial contract volume of up to 60,000 bpd of crude oil with provisions for volume increases. The Long Lake lateral agreement is for a term of 25 years and the agreement for service on the Athabasca Pipeline is for a 50-month term with extension provisions. 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. Construction of the laterals

and facilities is underway and expected to be in service in early 2007, to coincide with first production from the Long Lake Oil Sands Project.

4. New Market Access

The Company will develop new options to expand market access for Canadian crude. Specific initiatives include: extending the Mainline south of Chicago to Patoka, Illinois, expansion of the Spearhead Pipeline from Chicago to Cushing by 65,000 bpd, developing access to the Gulf Coast market directly from Alberta or through a combination of existing infrastructure and new pipelines, and accessing markets in Asia and California.

Southern Access Extension

The Southern Access Extension involves the construction of a new 36-inch diameter, 400,000 bpd pipeline extending the mainline from Flanagan, Illinois to Patoka at a cost of approximately US\$0.4 billion to Enbridge. Discussions with shippers have been finalized and, with industry support for this project, a FERC Offer of Settlement was filed on September 1, 2006.

The initial Offer of Settlement proposing a rolled in toll design was not approved by the FERC. However, support for the project remains very strong and Enbridge is working with industry on an alternative tolling structure to address the initial opposition from the intervening parties. The Company expects that a second application will be filed with the FERC in the first quarter of 2007 to allow the project to continue on schedule, with an estimated 2009 in-service date.

U.S. Gulf Coast Initiatives

The Company continues to meet with industry to explore and develop various options to enhance access to the U.S. Gulf Coast for Canadian supply. Alternatives under discussion include the development of incremental pipeline capacity to the U.S. Gulf Coast, given the projected increase in Canadian production. This interest includes support for a project from Patoka to the U.S. Gulf Coast to deliver an incremental 400,000 bpd of Canadian crude; and a new 400,000 bpd pipeline, which could transport oil from Alberta directly to Texas. This pipeline would also connect to refining centers in Denver, Colorado and Cushing.

The Company is examining greenfield pipeline options as well as the use of existing pipelines that may be candidates for reversal or expansion. The development of a number of alternative large diameter pipeline initiatives allows shippers to choose the projects that best meet their needs.

Eastern PADD II / Eastern Canada

Enbridge is exploring options to provide approximately 300,000 bpd incremental pipeline capacity to the Eastern PADD II region from the Chicago area in conjunction with potential expansion of existing lines serving the Sarnia, Ontario market.

The 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, Alberta area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat. The condensate line is expected 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.

Current shipper preferences to accelerate the development of capacity to traditional U.S. markets will likely result in the acceleration of the Alberta Clipper Project, such that it precedes the Gateway Pipeline project. The Company now estimates that the Gateway in-service date will be in the 2012 to 2014 timeframe. The decision to proceed with the regulatory filing for either pipeline is subject to commercial considerations, including satisfactory completion of shipper agreements, environmental assessment as well as public and Aboriginal consultation.

5. Diluent Supply Projects

Increasing heavy oil production 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 Midwest, as well as imported diluent supplies from the west coast of British Columbia, as described above in the Gateway Project.

Southern Lights Pipeline

Following the successful closing of a binding open season in July 2006, Enbridge announced plans in December 2006 to proceed with the Southern Lights Pipeline to increase the availability of diluent in Alberta. When completed, this 180,000 bpd, 20-inch diameter pipeline will transport diluent from Chicago to Edmonton and is expected to be in service in mid 2010.

The Southern Lights Pipeline project involves reversing the flow of a portion of Enbridge's Line 13, an existing crude oil pipeline, from Clearbrook, Minnesota to Edmonton. The Canadian portion of Line 13 is currently part of the mainline system and the U.S. portion of Line 13 is owned by EEP. 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 the expansion of existing Line 2. These changes to the existing crude oil system will ultimately increase southbound light crude system capacity by approximately 45,000 bpd. The capital cost of the Southern Lights project, including the new 20-inch diameter diluent pipeline, is estimated at approximately US\$1.3 billion.

In the fourth quarter of 2006, Enbridge received industry endorsement for the Southern Lights Pipeline project including an acceleration of the light crude capacity replacement and a delay in the transfer of Line 13 from the mainline system to the Southern Lights project. The impact of this change will be to increase the light crude system capacity on the mainline system by 215,000 bpd until the earlier of the completion of construction of new capacity out of the Western Canadian basin or the middle of 2010. On this date, Line 13 will be transferred to the Southern Lights project. Also during the fourth quarter, EEP approved the exchange of the portion of Line 13 currently owned by EEP for a portion of the Cromer to Clearbrook crude oil pipeline to be constructed. Remaining regulatory applications are expected to be filed in the first quarter of 2007.

6. Terminating and Storage Infrastructure

Based on producer interest, the Company plans to increase its investment in contract terminals over the next five years. Upstream contract storage 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

The Company plans to proceed with the construction of a new crude oil terminal at Hardisty, Alberta. The terminal is expected to have a capacity of 7.5 million barrels and will cost approximately \$0.4 billion. Enbridge has executed contracts for over 80% of the capacity and is close to closing contracts for the balance of the capacity. It is anticipated that the terminal will start to come into service early in 2008, with tanks being commissioned throughout 2008 and into 2009. An additional phase of development, which will increase the terminal's capacity by up to 3.4 million barrels, is planned and the Company is in discussions with customers who are seeking this additional capacity. 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 storage 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. These facilities are expected to be in service in mid-2008.

The Stonefell Terminal is also 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.

Downstream Terminaling

The Company continues to advance many downstream terminaling projects, including EEP-sponsored projects with an estimated US\$0.1 billion cost for adding approximately 5 million barrels of storage at Cushing in 2007. Enbridge is pursuing several other terminaling projects estimated at US\$0.2 billion with in-service dates of 2007 and 2008.

Capital Expenditures

Liquids Pipelines generally spends \$80 to \$100 million each year on ongoing capital improvements and core maintenance capital projects. In 2007, the Company expects to spend \$150 million on capital maintenance and improvements. Expenditures for organic growth projects described above were \$320 million in Canada for 2006. For 2007, the Company expects to spend \$1.3 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 has since appealed the decision and the appeal is expected to be heard by the Court of Appeal during the first half of 2007. 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 are dependent upon the supply of, and demand for, crude oil and other liquid hydrocarbons from Western Canada. Supply, in turn, is dependent upon 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 is dependent, among other things, on weather, gasoline price and consumption, manufacturing, alternative energy sources and global supply disruptions.

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 \$25 million in 2007 and \$30 million in 2008 and 2009.

Regulation

Earnings from 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 8.46% in 2007 (2006 - 8.88%). 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 can be reduced through the negotiation of long-term agreements with shippers.

Competition

Competition among common carrier pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service and contract carrier alternatives and proximity to markets. Other common carriers are available to producers to ship Western Canadian liquids hydrocarbons to markets in either Canada or the United States. As, well competition could 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 put forward 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 the 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. This can act as a barrier to entry for other companies considering constructing 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 and is exposed to volume fluctuations.

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 the Enbridge Offshore Pipelines.

Earnings

<i>(millions of Canadian dollars)</i>	2006	2005	2004
Alliance Pipeline US	29.7	32.1	37.4
Vector Pipeline	13.4	15.9	16.4
Enbridge Offshore Pipelines	18.1	11.8	-
	61.2	59.8	53.8

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 stronger Canadian dollar.

Earnings from Gas Pipelines were \$59.8 million for the year ended December 31, 2005, an increase of \$6.0 million from 2004. The increase in 2005 is due to incremental earnings from Enbridge Offshore Pipelines, acquired on December 31, 2004.

Revenues for the year ended December 31, 2006 were \$345.9 million consistent with \$364.3 million for the year ended December 31, 2005. Revenues for the year ended December 31, 2005 were \$364.3 million compared with \$271.7 million for the year ended December 31, 2004. The increase in revenues was due to the acquisition of Enbridge Offshore Pipelines on December 31, 2004.

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). Enbridge Income Fund, described under Sponsored Investments, owns 50% of the Canadian portion of the Alliance System.

Alliance connects with a natural gas liquids (NGL) extraction facility (Aux Sable) 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 \$29.7 million for the year ended December 31, 2006 compared with \$32.1 million for the year ended December 31, 2005. The decrease was primarily due to the stronger Canadian dollar.

Alliance Pipeline US earnings are \$32.1 million for the year ended December 31, 2005 compared with \$37.4 million for the year ended December 31, 2004. The moderate decrease is due to the stronger Canadian dollar in 2005.

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 20 mmcf/d of natural gas contracted on a short-term basis. These contracts permit Alliance to recover the cost of service, which includes operating and maintenance costs, 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 the depreciation expense in the financial statements is recorded on a straight-line basis of 4% per annum. The negotiated depreciated rates are generally less than the straight-line rates in the earlier years and higher than straight-line depreciation in later years of the shipper transportation agreements. This results in recognition of a long-term receivable, referred to as deferred transportation revenue, expected to be recovered from shippers in subsequent rates.

As at December 31, 2006 \$159.8 million (2005 - \$145.8 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 1.0 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 70% 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 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 \$13.4 million for the year ended December 31, 2006 compared with \$15.9 million for the year ended December 31, 2005. The decrease reflected the stronger Canadian dollar and higher operating costs in the second and third quarters of 2006 due to scheduled integrity inspections required by the regulator within the first six years of operation.

Vector Pipeline earnings were \$0.5 million lower for the year ended December 31, 2005 compared with the year ended December 31, 2004 resulting from the stronger Canadian dollar in 2005.

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, with a combined transportation capacity of approximately 3.8 bcf/d 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's 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 70% 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, Alliance Pipeline US files its annual rates with the FERC following consultation with shippers.

Enbridge Offshore Pipelines

Enbridge Offshore Pipelines (EOP) 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. The operations were purchased December 31, 2004. These pipelines include almost 2,400 kilometers (1,500 miles) of underwater pipe and onshore facilities and transport more than half of all current deepwater Gulf of Mexico natural gas production. These pipelines currently transport approximately 2.0 bcf/d.

Results of Operations

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 returned to 2005 pre-hurricane levels, resulting in increased earnings compared with 2005. The 2006 results were negatively impacted by the stronger Canadian dollar.

The Company continues to pursue the settlement of claims under its insurance policies for volume losses and additional costs the Company has incurred to restore the service capacity of these assets following hurricanes Rita and Katrina. A settlement of the insurance claim is anticipated in 2007.

Transportation Contracts

The primary shippers on the EOP systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, EOP 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 utilizing a cost-of-service methodology, which includes operating cost, projected revenue generation directly tied to production deliverability and the appropriate cost of capital.

Weather

Adverse weather, such as hurricanes, may impact EOP financial performance directly or indirectly. Direct impacts may include damage to EOP 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 EOP systems.

The Company continues to maintain an active risk management program that includes comprehensive insurance coverage, notwithstanding a constrained insurance market. 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 that 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. EOP has been able to capture key opportunities, extending its footprint, positioning it to more fully utilize existing capacity. EOP serves a majority of the strategically located deepwater host platforms and its extensive presence in the deepwater Gulf of Mexico has EOP well positioned to generate incremental revenues, with modest capital investment, by transporting production from sub-sea development of smaller fields tied back to existing host platforms. However, given

rates of decline, Offshore pipelines typically have available capacity resulting in significant and aggressive competition for new developments in the Gulf of Mexico.

Regulation

The transportation rates on many of EOP'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.

Strategy

The Company plans to continue to grow the Gas Pipelines segment to capitalize on regional supply and demand imbalances and infrastructure requirements through a combination of organic and acquisition opportunities. The Gas Pipelines strategy is based on the Company's forecast supply and demand for natural gas.

Supply and Demand for Natural Gas

North American natural gas demand is expected to grow at a modest rate for the next three to five years primarily driven by growth in power generation, which more than offsets declines in industrial demand. The re-emergence of coal as a generation source, due to advances in clean-coal technology, as well as the re-emergence of nuclear power as a source of electricity generation may reduce growth in the power related natural gas demand in the longer term. The development of oil sands projects in Alberta also increases the demand for natural gas, as various extraction and upgrading processes require the use of natural gas, however growth in this sector may also be tempered by alternative energy sources. Over time, the entry of new supplies from North Texas, the U.S. Rockies and the Alaska North Slope / Mackenzie Delta as well as Liquefied Natural Gas are expected to adequately supply the market and provide opportunities for Enbridge to deliver this natural gas to markets.

Specific strategies will be executed within two key geographic regions: Western Canadian/U.S. Midwest and Offshore Gulf Coast.

1. Western Canadian/U.S. Midwest Region

The Alliance and Vector Pipelines provide low cost expansion options to the Chicago/Dawn market and the Company plans to expand these systems and position Enbridge to participate in the Alaska gas pipeline. The Company also plans to develop takeaway capacity from Chicago to address the anticipated bottleneck from incremental Rockies and Arctic gas volumes. This could be accomplished through expansion of Vector Pipeline and potentially by developing a new route from Chicago to the U.S. Northeast.

Vector Pipeline Expansion

In 2005, Vector Pipeline announced plans to construct two additional compressor stations, which would expand Vector Pipeline's capacity from 1 bcf/d to 1.2 bcf/d. This expansion has been approved by the FERC and is scheduled to be in service in the fourth quarter of 2007.

2. Offshore Gulf Coast

EOP 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 EOP. A significant number of new discoveries exist on the shelf, in deepwater and the ultra-deep areas of the Gulf of Mexico in the corridors where EOP has existing pipeline facilities. EOP is continually monitoring and pursuing these many prospects. Two such projects under construction are described below.

Neptune Pipeline Project

The Company plans to construct and operate both a natural gas lateral and a crude oil lateral to 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. The laterals are expected to cost a total of approximately US\$0.1 billion and will have the capacity to deliver in excess of 200 million cubic feet per day (mmcf/d) of gas and approximately 50,000 bpd of oil. Construction of the natural gas and crude oil laterals is underway with sub-sea tie-ins scheduled for the second quarter of 2007 and throughput is expected to commence in the last half of 2007.

Shenzi Project

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

Capital Expenditures

The Company expects to spend approximately \$210 million in 2007 in the Gas Pipelines segment for ongoing capital improvements, core maintenance capital projects and expansion, including the projects described above. In 2006, the Company spent \$110 million on capital expenditures in the Gas Pipelines segment. Discussion of the Company's access to financing is included under Liquidity and Capital Resources.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 16.6% ownership interest in EEP and a 41.9% equity 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 Canadian dollars)</i>	2006	2005	2004
Enbridge Energy Partners	43.0	21.7	28.6
Enbridge Income Fund	37.8	34.2	30.0
Dilution gains	-	8.9	7.6
Revalue future income taxes due to tax rate changes	6.0	-	-
	86.8	64.8	66.2

Earnings from Sponsored Investments were \$86.8 million for the year ended December 31, 2006 compared with \$64.8 million in 2005. Earnings increased primarily because of strong results from EEP.

Earnings from Sponsored Investments were \$64.8 million for the year ended December 31, 2005 compared with \$66.2 million in 2004. EIF earnings increased due to allowance oil sales on the Saskatchewan System and collection of a notional tax in tolls on Alliance Canada. This increase was more than offset by EEP's non-cash unrealized mark-to-market losses on derivative instruments that are considered ineffective hedges for accounting purposes.

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, 2006, revenues were \$254.7 million consistent with \$249.0 million for the year ended December 31, 2005.

Revenues for the year ended December 31, 2005 were \$249.0 million compared with nil for the year ended December 31, 2004. The Company consolidates EIF under the variable interest entity rules, which came into effect on January 1, 2005. In 2004, the investment in EIF was accounted for as an equity investment.

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

EEP earnings 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.

Earnings of \$21.7 million for the year ended December 31, 2005 were down from 2004 earnings of \$28.6 million primarily due to \$5.0 million (net to Enbridge) of unrealized mark-to-market losses on derivative financial instruments, which did not qualify for hedge accounting treatment. In addition, EEP earnings were negatively affected by lower Lakehead System volumes, a stronger Canadian dollar and a lower ownership interest offset with higher earnings from the natural gas business.

EEP issued Class A partnership units in 2005 and 2004. Because Enbridge did not fully participate in the 2005 and 2004 offerings, dilution gains resulted. 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%.

Distributions

EEP makes quarterly distributions of its available cash to its common unitholders, including Enbridge. Under the Partnership Agreement, Enbridge, as general partner, 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.

	<u>Unitholders</u>	<u>Enbridge</u>
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 2006, EEP paid quarterly distributions of \$0.925 per unit (2005 - \$0.925 per unit; 2004 - \$0.925 per unit). Of the \$43.0 million Enbridge recognized as earnings from EEP during 2006, 37% (2005 - 65%; 2004 - 50%) were incentive earnings while 63% (2005 - 35%; 2004 - 50%) were Enbridge's share of EEP's earnings.

Strategy

EEP intends to increase its distributions through the optimization of existing assets including increased throughput, the expansion of the existing liquids and gas midstream businesses, and the acquisition of complementary assets. EEP will focus on assets that generate stable cash flows including crude oil mainline, feeder system and mid-continent terminaling, interstate and intrastate gas pipelines and certain gas gathering and processing 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 expansion. High gas prices 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 will allow it to aggregate volumes to improve margins and potentially underpin a new take-away pipeline capacity project. Examples of this aggregation include the recent expansion and extension of the East Texas system in the construction of additional pipeline infrastructure and the Alberta Clipper Project.

East Texas Clarity Project

The East Texas Clarity project, undertaken by EEP, is a US\$0.6 billion expansion of EEP's East Texas system and is progressing on-schedule to add 0.7 bcf/d of natural gas transportation capacity to the Texas intrastate market in 2007. The Clarity project will be completed in phases during the year with the first phase scheduled for completion in early 2007. This phase involves the construction of a natural gas treating facility and related mainline expansion. Additional phases of the project will be complete in mid-2007 and end of year 2007. When complete, the Clarity project will link growing natural gas production in East Texas, and third party storage assets in East Texas, with major third party pipelines and markets in the Beaumont, Texas area.

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, resulting in increased volumes for EEP.

EEP's natural gas gathering assets are also subject to changes in supply and demand for natural gas, natural gas liquids 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 natural gas liquids. Historically, these risks have been managed by using physical and financial contracts, fixing the prices of natural gas and natural gas liquids. Certain of these financial contracts do not qualify for cash flow hedge accounting and EEP's earnings are exposed to mark-to-market valuation changes associated with certain of these contracts.

Enbridge Income Fund

EIF's primary assets include a 50% interest in Alliance Pipeline Canada and the Enbridge Saskatchewan System, both purchased from the Company in 2003. The 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 waste-heat power generation projects at Alliance Pipeline Canada compressor stations.

Results of Operations

EIF earnings were \$37.8 million for the year ended December 31, 2006, comparable with the prior year, and reflected modest earnings growth at EIF. The increase in earnings reflected lower tax on distributions received from EIF.

EIF earnings were \$34.2 million for the year ended December 31, 2005 compared with \$30.0 million for the year ended December 31, 2004. The 2005 results include higher preferred unit distributions as well as higher incentive income consistent with EIF's cash distribution increases in 2004. EIF's operating results benefited from strong performance at both Alliance Pipeline Canada and the Saskatchewan System.

Tax Fairness Plan

On October 31, 2006, the Canadian Government announced a “Tax Fairness Plan” that would, among other things, create a new tax regime for publicly traded income trusts including EIF. Under the proposed rules, the taxable portion of an income trust’s distributions would be subject to taxation in a manner similar to the treatment of taxable income within a corporation. For existing income trusts, the new rules would not become applicable until 2011 provided they limit their expansion to “normal growth” prior to that year. On December 15, 2006 the Government issued guidelines with respect to what it would consider “normal growth” for existing income trusts that wish to ensure that they do not become subject to the proposed tax rules until 2011. Under these guidelines, the amount of equity units that an income trust can issue to finance growth up to 2011 may not exceed the value of its publicly traded equity units on October 31, 2007 (subject to annual limits). The guidelines do not explicitly limit the amount of debt that an income trust can issue to fund growth, although as a practical matter this will be constrained by credit considerations and/or financial covenants.

On December 21, 2006, the Government released draft legislation for comment. Considerable uncertainty still exists as the draft legislation does not fully address all aspects of the tax regime introduced in the Tax Fairness Plan (including the “normal growth” guidelines). Further, the proposed legislation is now subject to review by a Parliamentary committee through an expedited public hearing process. Timing for enactment of the legislation by Parliament remains uncertain.

If enacted in their present form, the proposed tax changes would, all other things being equal, likely result in a reduction of cash available for distribution by the Fund commencing in 2011. With respect to the proposed limitations on equity unit issuances, EIF should be able to fund its currently identified growth plans. However, with the current uncertainty in the capital markets resulting from the proposed tax changes, there can be no assurance that sufficient capital will be available to fund further acquisitions or expansion projects. EIF is closely monitoring legislative developments and carefully assessing the impact of the proposed legislation on the business and financial outlook of EIF and its broader effect on the income trust sector as a whole, all with a view to adopting a strategy that will maximize value to unitholders going forward once legislative framework is finalized.

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 2006, the Company received incentive fees of \$2.4 million (2005 - \$2.1 million, 2004 – \$0.8 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, starting January 1, 2005, under variable interest entity rules.

Strategy

EIF will maximize the efficiency and profitability of its existing assets through representation on the boards and/or management committees of EIF’s assets, pursue organic growth and expansion opportunities, invest in the Saskatchewan System expansion and Alliance Canada receipt facilities and expansions and pursue opportunities to acquire energy infrastructure investments or related assets.

Business Risks

Risks for Alliance Pipeline Canada are similar to those identified for the 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. Supply, in turn, is dependent upon a number of variables, including the level of exploration, drilling, reserves and production of crude oil and natural gas, the accessibility of Western Canadian crude oil and natural gas, the price and quality of crude oil and natural gas available from alternative Canadian and United States sources. In addition, the regulatory environments in Canada and the United States, including the continued willingness of the governments of both countries to permit the export of crude oil and natural gas from Canada to the United States on a commercially acceptable basis, could impact the supply of crude oil and natural gas.

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 Enbridge Gas Distribution (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 Canadian dollars)</i>	2006	2005	2004
Enbridge Gas Distribution ¹	61.8	111.9	133.1
Noverco ¹	22.7	28.3	32.3
CustomerWorks/ECS	18.8	23.2	20.5
Enbridge Gas New Brunswick	9.8	6.1	3.7
Other Gas Distribution ¹	6.5	6.7	8.5
Aux Sable	25.8	5.3	7.3
Gas Services	(1.5)	0.2	(2.8)
AltaGas Income Trust (AltaGas)	-	-	21.1
Gain on sale of investment in AltaGas	-	-	97.8
Impairment loss on Calmar gas plant	-	-	(8.2)
Other	5.4	(2.9)	(0.2)
Revalue future income taxes due to tax rate changes	28.9	-	-
	178.2	178.8	313.1

¹ Results for the year ended December 31, 2004 include earnings for the 15 months ended December 31, 2004.

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 the Aux Sable natural gas

fractionation facility due to upside sharing of positive fractionation margins under a new arrangement with BP and lower earnings from EGD resulting from warmer than normal weather and a lower allowed rate of return on common equity.

Earnings were \$178.8 million for the year ended December 31, 2005 compared with \$313.1 million for the year ended December 31, 2004. The 2004 earnings included 15 months of operations from the gas distribution operations as a result of the change in EGD's fiscal year end. Earnings for 2004 also included an after-tax gain of \$97.8 million on the sale of the investment in AltaGas Income Trust.

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 US operations in December 2005, resulting in a full year of revenues captured 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.

Revenues for the year ended December 31, 2005 were \$6,947.1 million compared with \$6,631.1 million for the year ended December 31, 2004. Revenues increased due primarily to increased commodity prices in Tidal which is included in Other.

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, 2006 were \$61.8 million compared with \$111.9 million for the year ended December 31, 2005. Warmer than normal weather in 2006 reduced earnings by \$36.9 million compared with relatively normal weather in 2005 which did not significantly impact earnings. EGD earnings were also reduced by a lower allowed rate of return on common equity, partially offset by a higher rate base. EGD's earnings are also affected by variances from the forecast cost of service, including operating and maintenance costs. EGD's costs can vary due to many factors including weather, project timelines and the timing of operating and capital expenditures.

Earnings for the year ended December 31, 2005 were \$111.9 million compared with \$133.1 million for the year ended December 31, 2004. Earnings for the year ended December 31, 2004 included 15 months of earnings for EGD, as a result of the elimination of the quarter lag basis of consolidation. Earnings for the extra quarter, the three months ended December 31, 2003, were \$11.5 million. Weather in 2004 was colder than normal resulting in an additional \$21.3 million in earnings. The remaining EGD variance is the result of a higher rate base and a number of smaller positive variances across the utility in 2005.

Normal weather is the weather forecast by EGD in its annual rates application, in the Toronto area, including the impacts of both the long run and short run actual historical weather experience, more heavily weighted on the short run experience, and is subject to OEB approval.

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 model weights the degree-days from the most recent years more heavily to determine the estimate. This weather-normalized adjustment method is the same as the manner in which EGD calculates degree-days for regulatory purposes.

2007 Rate Application

In August 2006, EGD filed an application with the OEB for approval of the 2007 rates, under a cost of service rate-making methodology. In January 2007, EGD arrived at an agreement to settle certain major issues in its rate application with key stakeholders. This settlement was approved by the OEB on January 29, 2007 and will allow EGD to continue operating within its current environment. A final decision on this rate application is expected during the second quarter of 2007. As part of its 2007 rate application, EGD has requested an increase in the equity component of its deemed capital structure for regulatory purposes. The requested 38% equity level reflects changes in EGD's current business risk environment and financial risk position relative to the current approved deemed equity level of 35%. The rate of return on common equity is calculated with reference to a formula approved by the OEB that incorporates the long bond yield forecast. The rate of return of 8.74% was used in the 2007 rate application as a placeholder and reflected the OEB approved return embedded within 2006 rates. The allowed return on equity for 2007, calculated in accordance with the OEB formula is 8.39%. This rate of return on common equity will replace the placeholder used by the Company in its 2007 rate application and will be embedded in 2007 rates.

Given the OEB's scheduled plan to move to Incentive Regulation, the Company expects 2007 to become the base year for a potential four to five year rate capped plan. The details of such plan are expected to be known in 2007. A description of Incentive Regulation is included below under "Strategy".

The key elements of the 2007 application and the 2006 and 2005 decisions are summarized below:

Regulatory year	Requested 2007	Approved 2006	Approved 2005
Rate base (<i>millions of Canadian dollars</i>)	\$3,801	\$3,634	\$3,422
Deemed common equity for regulatory purposes	38%	35%	35%
Rate of return on common equity	8.39%	8.74%	9.57%

The OEB released its decision relating to EGD's 2006 rate application on February 9, 2006. The new rates approved by the OEB's decision resulted in an overall increase in rates of approximately 1% for the average residential customer.

2006 and 2005 Rates

EGD's 2006 and 2005 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. The proportion of debt and equity, currently 65% and 35% respectively, is approved by the OEB. For the debt portion, interest expense incurred by the Company 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.

For 2004, rates were set by increasing 2003 rates by 90 percent of the forecast Ontario consumer price index, resulting in an increase of 1.8 percent. The OEB also added a sharing mechanism to fiscal 2004, whereby if earnings on a weather-normalized basis exceeded the benchmark ROE, these excess earnings would be shared on a 50/50 basis between ratepayers and the Company's shareholders.

Effects of Rate Regulation

EGD is subject to rate-regulation, therefore there are circumstances where the 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 such example. 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 company, providing safe and reliable distribution services to customers at fair and reasonable costs. To achieve this vision, EGD has outlined the following strategic objectives:

- to continue growth of the business through enhancement of infrastructure and storage facilities;
- improve opportunities for better returns through Incentive Regulation, which is expected to start in 2008;
- to be best-in-class in the safe and reliable operation of its gas distribution system;
- to be a leader in utility asset management; and
- enhance customer satisfaction by meeting customer commitments and enhancing value of services.

Customer Growth

A major strategic initiative is enhancing customer growth. EGD added over 47,000 new customers in the year ended December 31, 2006 (over 50,000 in the year ended December 31, 2005). The Company expects to continue to add 45,000 – 50,000 customers in 2007. New growth areas relating to construction heat, mass markets and distributed energy are also being pursued as part of a profitable utility growth portfolio. EGD will also lead research and development efforts into longer-term promising technologies that have the potential to retain and increase gas load and reduce operating costs while providing customer benefits. EGD has been successful in pursuing its industry facilitation strategy with the recent launch of

“EnergyLink”, a web-based tool that makes it easier for customers to find and install natural gas appliances.

Incentive Regulation

Improving the regulatory environment is also a key strategic thrust to provide greater operational and organizational flexibility. EGD will remain in a cost of service environment in 2007 but a change to Incentive Regulation (IR), is expected in 2008, with 2007 as the base year for a potential four to five year plan. Consultation with the OEB has commenced with respect to potential implementation of IR methodology for setting rates for services provided by EGD, which differs from the existing cost of service methodology. The potential impact on the future operating environment of EGD is not currently known, however EGD expects to obtain details on a proposed IR plan in the fourth quarter of 2007.

The following are the key anticipated parameters of IR:

- Inclusion of an appropriate annual adjustment mechanism to give effect to cost changes and productivity improvements, to ensure that benefits of efficiencies are shared with customers during the term of the plan;
- Mandatory cost of service rebasing at the end of each IR plan term and before a new plan is put in place to ensure that efficiency improvements will be identified and the benefits are passed onto customers through base rates for the following IR plan period;
- Earnings sharing mechanisms will not form part of IR plans, in order to provide a strong incentive to achieve sustainable efficiencies that can be shared with customers through the annual adjustment mechanism and rebasing; and
- IR term plans are expected to run between four and five years.

The objectives of IR are as follows:

- Reduce regulatory costs with less frequent hearings (maximum every 4 to 5 years) rather than every year under the current cost of service mechanism;
- Provide incentives for improved efficiency;
- Provide more flexibility for utility management; and
- Provide more stable rates.

Capital Expenditures

EGD’s capital expenditures in recent years have averaged approximately \$300 million per year. The capital expenditure budget is approved annually by the OEB, under the current cost of service environment.

Legal Proceedings

Class Action Lawsuit – late payment penalties

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

Under a settlement agreement approved by the Ontario Superior Court of Justice (the Court) in December 2006, EGD will contribute \$9 million to the Winter Warmth Fund (WWF), pay class counsel approximately \$10 million for the plaintiff’s legal fees and expenses and pay approximately \$2 million to the Class Proceedings Fund. The WWF provides eligible low-income customers of participating Ontario utilities with financial assistance for the payment of their natural gas and electricity bills. In accordance with the settlement agreement, EGD paid

\$2 million to class counsel shortly after the settlement agreement was executed, which amount was held in trust by class counsel until the settlement became final. EGD paid the remaining settlement amount of approximately \$19 million in January 2007. EGD has recorded a receivable from ratepayers for the total amount of \$21 million and will apply to the OEB for recovery of payments resulting from the settlement.

Bloor Street Incident

EGD has been 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. The maximum possible fine upon conviction on all charges would be \$5.0 million in 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 has also been called, but the proceedings are stayed pending resolution of the TSSA and OHSA matters. The courts have not yet ruled upon any of the charges laid under the TSSA or the OHSA, and thus it is not possible at this time to predict or comment upon the potential outcome. The trial in respect of these charges commenced January 3, 2006 and is not expected to be completed until well into 2007, at the earliest. EGD does not expect the outcome of these civil 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.

The business risks inherent in the natural gas distribution industry impact the ability of EGD to realize the revenue level required to generate the allowed return on equity. These business risks include obtaining timely and adequate rate relief, as well as accuracy in forecasting and realizing natural gas distribution volumes.

Volume Risks

Since customers are billed on a volumetric basis, the ability to collect the total revenue requirement (the cost of providing service) depends on achieving the forecast distribution volume established in the annual ratemaking process. The probability of realizing such volume is contingent upon weather; economic conditions; the price of gas relative to competitive energy sources; and the number of customer additions.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 77% (2005 – 78%) 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 2006, the winter months were warmer than forecast, resulting in an unfavourable weather related volume variance of 27.4 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 gas usage has declined by 1.2% 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.

Earnings from EGD are impacted to the extent that volumes sold differ from forecasted volumes. Key factors that affect the probability that EGD will distribute the forecast volumes include weather, economic conditions, gas prices and the prices of competing energy sources and the number of customers added. To the extent that these factors vary unfavourably compared with forecasts, EGD will not achieve the total revenue requirements established in the ratemaking process due to lower distribution volumes, thus resulting in lower earnings.

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.

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.

Rate Relief

The OEB has in the past, rendered decisions that have disallowed recovery of certain costs incurred by EGD. Through the regulatory process, the OEB approves the return on equity, which EGD is allowed to earn, in addition to various other aspects of utility operations.

Rate relief could be pursued for significant unforecasted amounts allowing EGD to recover the costs of providing and maintaining the quality of its service while achieving the allowed rate of return on rate base.

Forecasting Accuracy

EGD is exposed to forecasting accuracy risk as rates are established in advance, based on anticipated distribution volume by class of customer. Forecasts are also made for the future costs of debt and equity capital including the forecast yield rate for long-term Government of Canada Bonds used in the determination of the return on equity. Through the forecasting process, it is intended that any changes in cost of service, regardless of whether they are caused by inflation or by level of business activity, would be reflected in new rates applied for in the upcoming fiscal year.

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 should any similar proposal arise in the EGD franchise area.

Noverco

Enbridge owns an equity interest in Noverco through ownership of 32% of the common shares and a cost investment in preferred shares. Noverco is a holding company that owns approximately 71% 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 "Strategy" below).

Noverco also has an investment in the common shares of Enbridge resulting in dividend and earnings elimination adjustments at Enbridge. Noverco receives dividends from Enbridge but because Enbridge owns part of Noverco, a portion of the dividends Noverco receives are effectively dividends that Enbridge has paid to itself. This portion of the dividends paid reduces the book value of Enbridge's investment in Noverco.

Results of Operations

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 LP 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 the prior year included a future income tax recovery stemming from the receipt of a significant cash dividend.

Noverco earnings were \$28.3 million for the year ended December 31, 2005 compared with \$32.3 million for the year ended December 31, 2004. The 2005 results included the \$7.3 million dilution gain within Noverco on unit issuances by Gaz Metro. The 2004 results included 15 months of earnings as a result of the elimination of the quarter lag basis of consolidation. Earnings for the extra quarter, the three months ended December 31, 2003, were \$13.6 million. The remaining variance reflected the future income tax recovery related to the receipt of cash dividends net of an adjustment for reciprocal dividends.

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%.

CustomerWorks/ECS

CustomerWorks/ECS includes the operations of CustomerWorks and Enbridge Commercial Services (ECS). CustomerWorks is 70% owned by Enbridge and provides customer care services, including billing, collections, and operation of call centers primarily for; EGD, Direct Energy Essential Home Services and Terasen Gas (a gas distribution company in British Columbia). EGD is currently reviewing its customer care provider and expect to conclude this process in mid-2007. ECS owns the customer information services system that CustomerWorks uses under license to provide services to EGD.

Enbridge Gas New Brunswick

The Company owns 70% 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 5,600 customers. Approximately 565 kilometers (351 miles) of distribution main has been installed with the capability of attaching approximately 27,000 customers.

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.

Enbridge Gas New Brunswick earnings were \$6.1 million for the year ended December 31, 2005 compared with \$3.7 million for the year ended December 31, 2004. The increase is consistent with the settlement of debt through the issue of equity in 2005, resulting in a higher equity base.

EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities (PUB). As it is currently in the development period, EGNB's cost of service exceeds its distribution revenues. The PUB 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, 2006, the regulatory deferral asset was \$101.8 million (2005 - \$82.7 million).

Other Gas Distribution Operations

Earnings from Other Gas Distribution Operations were \$6.5 million consistent with \$6.7 million for the year ended December 31, 2005.

Earnings from Other Gas Distribution Operations decreased \$1.8 million in 2005, primarily because the 2004 results included 15 months of earnings as a result of the elimination of the quarter lag basis of consolidation. Earnings for the extra quarter, the three months ended December 31, 2003, were \$2.0 million.

Aux Sable

Enbridge owns 42.7% of Aux Sable, a natural gas liquids (NGL) extraction and fractionation business near Chicago. Aux Sable owns and operates a plant, at the terminus of the Alliance System. The plant extracts NGL 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 NGL, 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 NGL 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. 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, however Aux Sable has the right to reduce such losses to avoid termination.

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.

Fractionation margins are expected to moderate but remain favourable in 2007, given high oil prices and relatively low gas prices.

Earnings for the year ended December 31, 2005 were \$5.3 million compared with earnings of \$7.3 million for the year ended December 31, 2004. The decrease was due to higher natural gas costs in 2005, which were not offset by product sales prices causing weak margins and therefore decreased production levels.

Gas Services

The Company's Gas Services business 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. 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). In December 2005, capacity commitments on Vector Pipeline of 82.5 mmcf/d, previously held by EGD were assumed by the Gas Services business.

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 that the cost of transportation on these two pipelines exceeds the gas commodity basis differential, earnings will be negatively affected.

Other

Other earnings were \$5.4 million in 2006 compared with a loss of \$2.9 million in 2005. The 2006 results included an increased contribution from Tidal Energy, which resulted from the expansion of the business into the U.S. at the end of 2005 and increased earnings from its physical storage program.

In 2005, Other included higher costs, compared with 2004, related to the development of the Rabaska LNG facility.

Tidal Energy

Tidal Energy (Tidal) provides crude oil and natural gas liquids marketing services for the Company and its customers in a full range of condensate and crude oil types including light sweet, light and medium sours and several heavy grades. Tidal 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's business involves buying, selling and storing large quantities of crude oil. Tidal 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. Earnings from Tidal are included in Other.

AltaGas

The Company sold its investment in AltaGas in the third quarter of 2004 for an after-tax gain of \$97.8 million.

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,
- continuing to develop and grow the wind power platform in a measured fashion,
- 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 previously announced Rabaska LNG terminal to be located on the St. Lawrence River in Levis, Quebec. The Levis municipal council is fully supportive of the project and a fiscal agreement has been executed. Options for all required land have been secured. Environmental and marine applications have been filed and are progressing. It is expected that all required permits would be obtained by early summer 2007. Discussions are in progress with potential LNG suppliers regarding long-term terminal use arrangements. The project is expected to cost approximately \$840 million in total.

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. Construction will commence when final environmental and zoning approvals are obtained. The project is waiting for its Environmental Screening Report to be passed by the Ontario Ministry of Environment and its zoning laws to be approved by the Ontario Municipal Board. Total capital expenditures are expected to be approximately \$0.5 billion. Enbridge has entered into a 20-year electricity purchase agreement with the Ontario Power Authority for all the power produced by the project. The Company expects the Ontario Wind Project to be in service in late 2008.

Capital Expenditures

Capital expenditures in other Gas Distribution and Services businesses, including the Ontario Wind Project, described above, are expected to be approximately \$225 million in 2007.

INTERNATIONAL

International includes earnings from the Company's 25% interest in Compañia Logistica de Hidrocarburos CLH, S.A. (CLH), Spain's largest refined products transportation and storage business, and Oleoducto Central, S.A. (OCENSA), a crude oil pipeline in Colombia. Earnings also include fees earned from technology and consulting services provided by Enbridge Technology Inc.

Earnings

<i>(millions of Canadian dollars)</i>	2006	2005	2004
CLH	54.5	61.6	48.6
OCENSA/CITCoI	33.9	32.8	33.0
Other	(5.2)	(7.0)	(8.0)
	83.2	87.4	73.6

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.

Earnings for the year ended December 31, 2005 were \$87.4 million compared with \$73.6 million for the year ended December 31, 2004. The increase results primarily from the \$7.6 million gain on the sale of land in CLH. Operating results at CLH were also improved due to higher volumes and increased average tariffs and storage revenues.

Other includes administration and business development costs and the financial results of Enbridge Technology Inc.

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 basis. The system consists of over 3,400 kilometers (2,113 miles) of pipelines and 38 storage facilities located throughout the country. CLH provides product distribution to locations not connected to the pipeline system through its own fleet of tanker trucks and chartered tanker ships. CLH also offers secondary distribution services, the most significant being the services provided through CLH Aviation, which handles aviation fuel at airport locations throughout Spain. This business includes the storage of aviation fuel, loading of aircraft refueling units and the refueling of aircraft. New policies issued by the Spanish airport authority (AENA) to promote competition, allow for new non-CLH operators to enter the aircraft-refueling segment of this business. While CLH's share of this segment of the market may reduce over time, its participation in the aviation fuel business will 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.

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. This expansion, which includes an increase in storage capacity and looping of both the northern and southern main lines, will be constructed in phases to match the expected growth in volumes.

OCENSA/CITCol

The Company owns a 24.7% interest in OCENSA, a cost investment on which the Company earns a fixed return. OCENSA is one of two crude oil export pipelines within Colombia. Through a 100% owned entity, CITCol, the Company manages the pipeline and earns a fee for this service, which includes incentives for operating performance.

Strategy

The Company plans to increase International earnings contribution over the next several years by leveraging its North American operating expertise in midstream energy infrastructure and relationships with existing partners. The Company will pursue investment opportunities in regions or countries with attractive fundamentals of supply and market demand, in which operating and political risks are acceptable to the Company, and in which attractive risk adjusted returns are available.

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.

C O R P O R A T E

<i>(millions of Canadian dollars)</i>	2006	2005	2004
Corporate	(82.2)	(63.9)	(81.3)
Revalue future income taxes due to tax rate changes	14.0	-	-
	(68.2)	(63.9)	(81.3)

The Corporate segment includes corporate financing costs, business development activities and other corporate costs not attributable to a specific business segment.

Corporate costs were \$82.2 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.

Corporate costs were \$63.9 million for the year ended December 31, 2005 compared with \$81.3 million for the year ended December 31, 2004. Corporate costs were lower in 2005 reflecting lower interest expense due to lower rates. Also, business development costs were higher in 2004.

L I Q U I D I T Y A N D C A P I T A L R E S O U R C E S

The Company's cash generated from operations, commercial paper issuances, available capacity under credit facilities and access to capital markets in Canada and the United States for the issuance of long-term debt, equity, or other securities are expected to be sufficient to

satisfy liquidity and capital expenditure requirements. Subsequent to December 31, 2006, the available capacity under credit facilities was increased to approximately \$4.0 billion.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The debt to capitalization ratio at December 31, 2006, including short-term borrowings, but excluding non-recourse short and long-term debt, was 64.6%, compared with 64.5% at the end of 2005.

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.

The Company's cash balance at the end of the year includes \$7.2 million (2005 - \$16.4 million; 2004 - \$6.0 million) held in trust in joint ventures, pursuant to finance agreements within the joint ventures.

Operating Activities

Cash from operating activities increased to \$1,297.7 million for the year ended December 31, 2006 from \$947.0 million for the year ended December 31, 2005 and \$886.7 million for the year ended December 31, 2004.

<i>(millions of Canadian dollars)</i>	2006	2005	2004
Earnings net of non-cash items	1,171.0	1,300.9	1,027.8
Changes in operating assets and liabilities	126.7	(353.9)	(141.1)
Cash Provided by Operating Activities	1,297.7	947.0	886.7

Cash provided by earnings net of non-cash items, was \$1,171.0 million for the year ended December 31, 2006, compared with \$1,300.9 million and \$1,027.8 million for 2005 and 2004, respectively. In 2005, the Company received special dividends from Noverco totaling \$70 million which resulted in most of the variance between 2005 and 2006.

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. This caused reductions in accounts receivable and gas inventories in the current year, compared to increases in the prior year, partially offset by a decrease in payables in the current year, compared with an increase in the prior year, all within EGD.

Changes in operating assets and liabilities were lower in 2005 compared with 2004. The majority of this change was in EGD where higher commodity prices in 2005 increased accounts receivable and inventory.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2007.

Investing Activities

Cash used for investing activities for the year ended December 31, 2006 was \$1,580.0 million 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 and a \$280.2

million investment in EEP as well as the acquisition of a 65% interest in the Olympic Pipeline for \$101.4 million.

In 2005, the majority of cash spent on investing was for additions to property, plant and equipment, primarily in EGD. The increase in additions to property, plant and equipment in 2005, compared with 2004, was due to increased expenditures on capital projects. In 2005, the Company also made contingent payments to the former owners of the Company's 25% interest in CLH because CLH met cumulative volume targets. In 2004, the Company also made smaller contingent payments to the former owners of the 25% interest in CLH.

In 2005, the Company made minor acquisitions throughout the year amounting to \$88.6 million whereas, in 2004, \$833.9 million was used for acquisitions including Enbridge Offshore Pipelines, acquired for \$743.4 (net of cash acquired) and other minor acquisitions. Cash proceeds from the sale of the investment in AltaGas partially offset the use of cash for acquisitions in 2004.

Financing Activities

In 2006, the Company generated \$268.1 million through financing activities compared with cash used for financing activities of \$22.1 million in 2005 and cash generated during 2004 of \$114.4 million.

During 2006, the Company issued \$1,125.0 million of new long-term debt in the form of medium term notes and repaid \$400.0 million in medium term notes which matured during 2006. Short-term borrowings at EGD are used primarily to finance working capital, including inventory. EGD's short-term borrowings decreased by \$266.9 million in 2006, 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.

Throughout 2005, the Company issued \$1,020.1 million new long-term debt. This new debt replaced higher interest rate medium-term notes, which matured during 2005, and short-term debt, primarily commercial paper. The repayment of short-term debt was partially offset by an increase in short-term borrowings at EGD. EGD's short-term borrowings were higher at the end of 2005 due to increased commodity prices.

Dividends on common shares have increased again in 2006 due to an increased number of common shares outstanding and a higher dividend rate.

In 2004, cash was generated through a net issuance of \$788.0 million of debt, partially offset by the payment of dividends. The Company also repaid \$350.0 million of preferred securities at the end of 2004.

Debt Covenants

Enbridge Inc. and all of its subsidiaries are in compliance with all debt covenants. However currently, EGD does not meet a new long-term debt issuance test contained in its trust indenture due primarily to significantly warmer weather and a decline in EGD's allowed return on equity. In order for EGD to issue new long-term debt, EGD requires a long-term debt interest coverage ratio of 2.0 times for 12 consecutive months out of the last 23 months. Although EGD cannot issue new long-term debt until it meets the test, EGD may refinance existing long-term debt or issue new short-term debt without having to meet the new issue test.

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%. Gross proceeds from both offerings were \$581.2 million.

Preferred Securities

The Company has \$200.0 million of 7.8% Preferred Securities outstanding. On December 18, 2006, the Company announced its intention to redeem all 8,000,000 Preferred Securities on February 15, 2007 for \$25.00 per Preferred Security plus accrued and unpaid interest of \$0.2458 per security for the period covering from the last interest payment date of December 31, 2006 to the redemption date of February 15, 2007.

Expected Capital Expenditures

The numerous potential 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 \$2.5 billion during 2007 on capital projects and maintenance. The Company expects to finance these expenditures through cash from operating activities, the equity issuance described above and additional debt, if required.

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 Canadian dollars)</i>	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt	7,574.4	535.3	800.0	748.4	5,490.7
Non-recourse long-term debt	1,566.9	58.4	301.3	180.0	1,027.2
Capital and operating leases	85.6	7.4	14.2	12.3	51.7
Long term contracts ¹	1,306.1	454.2	309.1	256.6	286.2
Total Contractual Obligations	10,533.0	1,055.3	1,424.6	1,197.3	6,855.8

1. Approximately \$214.4 million of these contracts are commitments for products related to the construction of Liquids Pipelines projects; the minimum cancellation charge related to these contracts is \$127.2 million.

SENSITIVITY ANALYSIS

The Company's earnings will fluctuate with changes in the market prices and certain volumetric parameters, such as weather. Enbridge manages its financial market risks through an Earnings at Risk (EaR) metric. Under the Company's EaR policy, using a two standard deviation confidence interval, the maximum adverse change in 12 months forward earnings from movements in market prices over a 1 month period of time will not exceed 5% of earnings. On December 31, 2006, the Company's EaR was 2.9%.

The following table shows the effect of changes in certain key financial market variables on earnings. These sensitivities are approximations based on business conditions as of December 31, 2006 and may not be applicable to other periods, under other economic conditions or for greater magnitude changes.

Factor	Change	After-Tax Earnings Impact
Exchange rate (CAD Dollar to US Dollar)	CAD\$0.01	\$1.1 million
Exchange rate (CAD Dollar to Euro)	CAD\$0.01	\$0.3 million
Interest rates	0.5%	\$4.0 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 and as such, these fluctuations have been excluded from the Company's EaR metric. The Company hedges the foreign currency risk of dividends it receives from foreign currency denominated subsidiaries. Any unhedged foreign currency dividends are captured in the EaR metric.

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	18 degree days	1 billion cubic feet
Volume	1 billion cubic feet	\$1.3 million (after-tax)

In 2006, weather negatively impacted earnings by a larger magnitude than the above sensitivities would suggest. This resulted from the unusual pattern of distribution 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 market price, credit, and operating risks. The Company has formal risk management policies and risk management systems designed to mitigate these risks.

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 Earnings at Risk. It is an objective, statistically derived risk metric that measures the maximum earnings loss that could result from

adverse market price movements over a specified time horizon within a pre-determined level of statistical confidence, under normal market conditions.

The Company uses derivative financial instruments for risk management purposes. The following summarizes the types of market price risks to which the Company is exposed and the 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 risk. Furthermore, the Company is exposed to the economic risk on the conversion of the foreign currency denominated cash flows. 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.

The Company hedges certain of its foreign currency denominated net equity investments with the use of cross currency swaps, par forward contracts, and foreign currency denominated debt. These long-term derivative contracts also serve to economically hedge a significant portion of the cash distributions from these equity investments. However, this does not eliminate the GAAP earnings volatility caused by exchange rate differences. During the year ended December 31, 2006, the Company received foreign currency denominated cash distributions and settled associated hedge transactions resulting in \$17.1 million (2005 - \$13.0 million) of incremental cash flows, which were not included in reported earnings.

Interest Rate Risk

Enbridge is exposed to interest rate fluctuations on 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 15% 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 itself is included in Notes 12 and 17 of the Company's consolidated financial statements for the year ended December 31, 2006.

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 natural gas liquids derivative instruments to fix the value of variable price exposures that arise from commodity usage, storage and supply agreements.

Natural Gas Supply Management

Customers of EGD are exposed to changes in the price of the natural gas commodity. A portion of the future natural gas supply requirements is hedged using natural gas swaps and options that manage the price of natural gas, as allowed by the OEB. Since customers pay the cost of

the natural gas commodity, this risk mitigation strategy is for the benefit of customers. The OEB monitors the policies, procedures, and results of this hedging program.

Fair Values of Derivative Instruments

Information about the financial instruments outstanding at year end for the purposes of mitigating the risks as described above, including the fair values, notional or principal amounts and maturities are shown in Note 17 of the Company's Consolidated Financial Statements for the year ended December 31, 2006.

Credit Risk

Entering into derivative financial instruments can give rise to additional credit risks. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company 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.

Trade receivables include amounts due from companies operating in the oil and gas industry and are collateralized by the commodities contained in the Company's pipelines and storage facilities. Where shippers fail to maintain specified credit ratings they are required to provide letters of credit or other suitable security. Credit risk in the Gas Distribution and Services segment is reduced by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. For customers of our non-regulated businesses, credit exposure is minimized through the use of credit monitoring processes, contractual agreements with collateral requirements, master netting agreements, and credit exposure limits.

Operating Risks

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 accidents, 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. Finally, 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.

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 accidents 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.

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 predictive and detective 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.

Execution Risk

Cost escalation and internal and external resource shortages, including human resources, may adversely affect the Company's ability to develop and complete organic growth projects in a cost effective and timely manner. In addition, there are a number of competing projects, proposed by other companies, which could preclude the Company from developing one or more of the proposed projects.

CRITICAL ACCOUNTING ESTIMATES

Depreciation

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2006 of \$11,264.7 million, or 61% of total assets, generally is 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 does not reflect the expected remaining period of benefit, prospective changes are made to the estimated service life. In general, estimates of service lives are based on third party engineering studies, experience and 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, with the exception of the Corporate segment. Generally, revised assumptions have historically resulted in extending useful lives. 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.

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 National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy and Utilities Board (AEUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking, and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities. The Company also 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, 2006, the Company's regulatory assets totaled \$574.1 million (2005 - \$542.5 million) and regulatory liabilities totaled \$148.6 million (2005 - \$24.7 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 post-employment benefits 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 19 to the 2006 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.

Impact of a 0.5% Change in Key Assumptions <i>(millions of dollars)</i>	Pension Benefit		OPEB	
	Obligation	Expense	Obligation	Expense
Decrease in Discount Rate	79.2	9.3	15.4	1.8
Decrease in expected return on assets	n/a	4.9	n/a	0.2
Decrease in rate of salary increase	(18.3)	(4.0)	-	-

Contingent Liabilities

Provisions for claims filed for damages 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. The final determination by the courts in respect of the claims outstanding 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. as disclosed in Note 23 of the 2006 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. Therefore, changes in 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, Hedging Relationships and Other Comprehensive Income

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

The Company will recognize other comprehensive income in a separate financial statement and include accumulated other comprehensive income as a component of shareholders' equity. To the extent economic hedges do not qualify for hedge accounting, are ineffective, or are not documented as hedges in accordance with the new standards, gains and losses and any ineffectiveness will be charged to current period earnings.

If the Company were to adopt the standards at December 31, 2006, a payable to counterparties of \$43.1 million, a due from ratepayers of \$26.6 million, accumulated other comprehensive income of \$31.2 million, a future tax liability of \$16.8 million, and a charge to retained earnings of \$64.5 million would be recognized in the financial statements.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in the rules of the Securities and Exchange Commission and the Canadian Securities Administrators) and concluded that the Company's disclosure controls and procedures were effective as of December 31, 2006 and in respect of the 2006 year-end reporting period.

Management's Report on Internal Controls 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 generally accepted accounting principles.

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 our policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, 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, 2006.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report included with the Company's audited financial statements.

QUARTERLY FINANCIAL INFORMATION¹

(millions of Canadian dollars, except for per share amounts)

2006	First	Second	Third	Fourth	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

(millions of Canadian dollars, except for per share amounts)

2005	First	Second	Third	Fourth	Total
Revenues	2,555.8	1,527.4	1,657.1	2,712.8	8,453.1
Earnings applicable to common shareholders	220.6	93.6	67.8	174.0	556.0
Earnings per common share	0.66	0.27	0.20	0.52	1.65
Diluted earnings per common share	0.65	0.27	0.20	0.51	1.63
Dividends per common share	0.2500	0.2500	0.2500	0.2875	1.0375

1. Quarterly Financial Information has been extracted from financial statements prepared in accordance with generally accepted accounting principles.

Quarterly operating revenue fluctuates primarily due to the seasonality of the Company's gas distribution business. Typically, revenue peaks in the winter months during the first quarter and, to a lesser extent, in the fourth quarter when higher volumes are delivered and sold. Also, 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 2006 and 2005 quarterly earnings are as follows:

- Fourth quarter 2006 earnings reflected higher earnings from the mainline system and Aux Sable, offset by lower earnings from EGD due primarily to warmer than normal weather and higher costs in the fourth quarter of 2006.
- Third quarter 2006 earnings reflected higher earnings from Enbridge System, increased earnings from the Company's investment in EEP and the initial recognition of upside sharing in Aux Sable which resulted from high fractionation margins.
- Second quarter earnings in 2006 included the impact of tax rate reductions, which increased earnings by a total of \$48.9 million. Revenues in the second quarter of 2006 were higher than the second quarter of 2005 due to higher commodity prices and were offset by higher commodity costs, as EGD passes through to customers changes in the price of natural gas.
- First quarter earnings in 2006 reflected improved earnings in the Enbridge System more than offset by lower results from EGD, due primarily to warmer than normal weather. Revenues in the first quarter of 2006 were higher due to higher commodity prices and were offset by higher commodity costs.
- Fourth quarter earnings in 2005 include a gain of \$7.6 million on the sale of land in CLH and a dilution gain of \$4.3 million in EEP.
- Third quarter earnings in 2005 were negatively impacted by Hurricanes Katrina and Rita and by non-cash losses on the fair value of derivatives in EEP.
- First quarter earnings in 2005 include dilution gains in EEP and within Noverco totaling \$11.9 million.

FOURTH QUARTER 2006 HIGHLIGHTS

Fourth quarter earnings for 2006 were \$171.1 million, or \$0.50 per share, compared with \$174.0 million, or \$0.52 per share, in 2005. The fourth quarter of 2006 reflected higher earnings from the Enbridge crude oil mainline system and Aux Sable, offset by lower earnings from EGD due primarily to warmer than normal weather and higher costs in the fourth quarter of 2006.

SELECTED ANNUAL INFORMATION

<i>(millions of Canadian dollars, except per share amounts)</i>	2006	2005	2004
Dividends Per Common Share	1.15	1.0375	0.92
Common Share Dividends	403.1	361.1	315.8
Total Assets	18,379.3	17,210.9	14,905.1
Total Long-Term Liabilities	10,544.8	9,690.7	8,182.5

Total assets and total long-term liabilities increased from 2005 to 2006 because of ongoing investments in core businesses and a \$280 million investment in EEP, increasing the Company's interest from 10.9% to 16.6%.

Total assets and total long-term liabilities increased from 2004 to 2005 primarily because the Company began consolidating its 41.9% investment in EIF. This change was due to the adoption of Accounting Guideline 15, Consolidation of Variable Interest Entities (AcG-15). Under AcG-15, EIF is considered a variable interest entity and Enbridge is the primary beneficiary through a combination of a 41.9% equity interest and a preferred unit investment that has no voting rights, a stated par value and a 30-year maturity.

SUPPLEMENTARY INFORMATION

Outstanding Share Data	Number outstanding
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares – issued and outstanding (voting equity shares)	351,920,358
Total issued and outstanding stock options (7,558,307 vested)	11,643,157

Outstanding share data information is provided as at February 12, 2007.

RELATED PARTY TRANSACTIONS

Information about the Company's related party transactions is included in Note 22 to the Company's consolidated financial statements for the year ended December 31, 2006.

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

Dated February 21, 2007